Rampion Offshore Wind Farm

ES Section 2a – Offshore Project Description

RSK Environmental Ltd

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Revision A

E.ON Climate & Renewables UK Rampion Offshore Wind Limited

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2a PROJECT DESCRIPTION (OFFSHORE)

2a.1 Introduction

2a.1.1 This section describes the offshore components of the Rampion Offshore Wind Farm (the Project). These include:

- The indicative wind farm site layout, comprising the turbines, their foundations, the offshore substations and the inter-array cables; and
- The subsea marine export cable corridor (i.e. the electrical cables connecting the offshore substations to shore).

2a.1.2 The works involved in the chronological phases of the offshore components are also described in relation to the construction, operation and maintenance, and decommissioning phases.

2a.1.3 Descriptions of the onshore components of the Project are set out in Section 2b.

2a.2 The Project

Offshore Definitions

2a.2.1 Throughout this ES a number of terms are used to describe different geographic areas and sites relating to the offshore components of the Project, which are those located seaward of the mean high water springs tide line (MHWS).

2a.2.2 The "Project site" forms the boundary of all possible development associated with the Project. The offshore aspects (Offshore Project) comprise the following areas:

- "Offshore Array": (the offshore area in which all turbines, offshore substations and inter-array cables will be located);
- "Export cable corridor": the area in which the export cables will be located, connecting the Offshore Array to the Landfall at the coast; and
- "Landfall": the area between the transition pit and the mean low water springs tide line (MLWS), of which the area between MLWS and MHWS is considered part of the Offshore Project.

2a.2.3 In addition a further area is referenced in the ES:

- "The Crown Estate Zone 6": the larger offshore area to which The Crown Estate (TCE) granted exclusive development rights to E.ON. E.ON have chosen to develop the Offshore Array within the northern part of this Zone.

Overview

2a.2.4 The area of the Offshore Array is approximately 139km^2.

2a.2.5 The Project will have a maximum installed capacity of 700MW and will comprise up to 175 three bladed, horizontal axis wind turbines.

2a.2.6 The Crown Estate would be able to grant a seabed lease for 50 years should the Project receive consent. The design life of current wind turbine technology is typically 20-25 years. At the end of this period a decision would need to be made whether to refurbish the scheme, replace it with newer turbine technology, or decommission the project. Any material changes to the Project at this stage would require a new consent application and would be subject to further Environmental Impact Assessment.

2a.2.7 The final Project details (e.g. the precise siting and turbine class, type of foundation etc) are not yet determined. Therefore a number of options will remain under consideration until further detailed engineering work has been undertaken, which will include:

- Detailed geotechnical investigations of the seabed;
- Foundation and engineering design;
- Economic assessments; and
- The selection and appointment of equipment and contractors.

Project Design Envelope

2a.2.8 Due to the complexity of developing large offshore wind farms, it is not possible to make final design decisions for a number of elements of the Project, such as the foundation type, array layout, turbine model, or certain elements of the offshore export cable route and offshore substations, at this stage. Flexibility in the design process is essential to ensure that the development can take account of environmental, technological and economic factors that may arise during the development process.

2a.2.9 The accepted approach to applying for development consent for an offshore wind farm is to use a project definition that is sufficiently flexible to allow the future incorporation of best available technologies in an optimised detailed design.

2a.2.10 This approach to project development and associated consenting uses the Rochdale Envelope[1] principle (see Section 5 – EIA Methodology). This principle is

[1] Case law (i.e. R.V Rochdale MBC Ex. Part C Tew 1999) – The “Rochdale Case”, established that indicative sketches and layouts etc. cannot provide a sufficient basis for outline planning permission for EIA Development. Therefore, with respect to the DCO application, the final scheme constructed must have been covered by the scope of the EIA.

an accepted way of dealing with uncertainty where impacts associated with a project are assessed using a 'realistic worst-case scenario' approach.

2a.2.11 The aim is to assess a maximum adverse scenario (the 'realistic worst case') in environmental terms. The realistic worst case scenario may differ for each topic, as the significance and magnitude of any particular impact may differ for different receptors. For example, the design and installation of turbine foundations can have very different implications for benthic invertebrates and marine species such as fish, diving birds and marine mammals, which are sensitive to underwater noise. If gravity base foundations are used they impact upon the widest seabed area, but are relatively "low-noise" during installation; conversely if monopile foundations are selected they have a relatively low seabed "take", but would generate highest levels of underwater noise during installation.

2a.2.12 The Project's design envelope has to demonstrate that it provides sufficient detail to properly assess the appropriateness of the application, whilst allowing the developer scope to effectively respond to technological and commercial developments.

2a.2.13 Considerable engineering, design and environmental assessment has been undertaken to provide a carefully considered design envelope for the Project. As EIA is an ongoing and iterative process, the assessment presented in this ES covers the breadth of Project design parameters which will be used in the final design.

2a.2.14 The following paragraphs describe the range of Project design options that are being considered within the Project design envelope. Under each assessment section, the applicable envelope parameters are set out, describing the realistic maximum adverse scenario considered.

2a.3 Project Site Description

2a.3.1 The Crown Estate Zone 6 lies in the English Channel off the Sussex Coast. The Zone is has an overall area of 271km^2 and is partly defined by known navigational and other constraints, including the Traffic Separation Scheme and Inshore Traffic Zone (ITZ) of the eastern English Channel approximately 2.8nm to the south and licensed aggregates extraction areas to the west.

2a.3.2 E.ON is proposing to develop the Offshore Array wholly within the Zone, which covers 139km^2 of the total Zone area. This area has been chosen given its relatively shallow water depth.

2a.3.3 A small part of the Offshore Array coincides with an area over which TCE has granted an aggregates extraction option, which is valid until 2013. It has been indicated by the aggregates option holder that they intend to exercise the option and take up a long-term licence for extracting aggregates from this area.

Assuming this is the case, this legal interest over this area of seabed would take precedence and no wind farm development would occur within this area.

2a.3.4 However, in the event that the aggregates option is not exercised, then the installation of wind turbines within this area would be possible.

2a.3.5 A Memorandum of Understanding (MoU) has been drawn up between E.ON and the aggregates extraction option holder to set out how things will work in practice, including buffer zones to ensure safe co-existence of wind farm and aggregates interests.

2a.3.6 Additionally there are currently active aggregates extraction licenses located to the west of the Offshore Array. Whilst there is no overlap between the wind farm site and these aggregates areas, it is important that the right mitigations are put in place to ensure no conflicts arise between the aggregates and wind farm activities occurring within relatively close proximity to each other. Productive dialogue is ongoing with the aggregates companies who dredge these areas to discuss and agree appropriate measures.

The nearest coastal ports are Brighton, Newhaven, Shoreham-by-Sea and Littlehampton. The Zone and Offshore Array's area co-ordinates are presented in Table 2a.1 and

2a.3.7 Table 2a.2 respectively, and shown on Figure 2a.1.

Table 2a.1: Zone co-ordinates (WGS84)

	Latitude	Longitude
A	50.686487	-0.365516
B	50.706896	-0.229361
C	50.677554	-0.073953
D	50.629706	0.052275
E	50.583913	-0.100292
F	50.595586	-0.336293

Table 2a.2: Offshore Array co-ordinates (WGS84)

	Latitude	Longitude
1	50.686500	-0.365516
2	50.706901	-0.229360
3	50.677600	-0.073953
4	50.658798	-0.024461
5	50.643001	-0.150802
6	50.618900	-0.261705
7	50.637001	-0.271412
8	50.617599	-0.343360

Water Depths

2a.3.8 Water depths in the Offshore Array area range from a minimum of 18m below Lowest Astronomical Tide (LAT)[2] in the north-west, deepening to a maximum of 59m below LAT in the south-east. Water depths in the export cable corridor range from 0m at landfall to greater than 30m in the south-east corner.

2a.3.9 The tidal range within the Zone is of the order of 7m LAT to HAT.

Seabed Gradient, Bathymetry and Geology

2a.3.10 Seabed gradients across the Offshore Project site are relatively gentle, being <1° in the export cable corridor and the majority of the Offshore Array area. There is some bathymetric variation due to channel features, sandwaves and megaripples in the southern end of the Offshore Array. Increased gradients of up to a maximum of 14° can be found on the steeper sides of the largest asymmetric sandwaves (Osiris Projects, 2010).

2a.3.11 The seabed is predominantly formed of sands and gravels, overlying normally consolidated sands and clays with some peat layers and basal gravels. The fine grained sediments are relatively mobile, with static surface sediments comprising coarse-grained lag deposits. The tidal regime controls the sediment mobility.

2a.3.12 The Quaternary sequence across the Offshore Project and surrounding area comprises a sequence of variable fine to coarse soils generally between less than a metre and up to 30m thick, with the thickest areas interpreted to be associated with a number of infilled, submerged glacial channels. The solid geology of the Offshore Project is characterised by Tertiary Clays and Upper Cretaceous Chalk with flint, the latter outcropping and subcropping from Beachy Head to Bognor Regis. Tertiary rocks subcrop beneath seabed sediments off Worthing, Brighton and Beachy Head and extend out into the Channel.

Environmental Designations

2a.3.13 There are no national or international environmental designations in the Offshore Project, although a local Marine Site of Nature Conservation Importance (MSNCI) – the *City of Waterford* wreck is located within the Offshore Array area (see section 9 – Nature Conservation). The closest currently designated international site with marine features is Solent Maritime Special Area of Conservation (SAC) situated around 38km away, while there are several recommended Marine Conservation Zones (rMCZs) closer to the wind farm site and cable route corridor (see Section 9 – Nature Conservation).

2a.3.14 There are a number of sites inshore of the Offshore Array which are designated for their nature conservation interest, and these are detailed in Section 9 - Nature Conservation, and summarised in section 2a.4.13.

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[2] All depths quoted relate to Lowest Astronomical Tide (LAT), unless otherwise stated.

Wind Resource

2a.3.15 Data originally from the Department for Business, Enterprise and Regulatory Reform (BERR) gives the annual mean wind speed at the site, at 100m, as 9.15m/s. This indicated that the site would be suitable for an offshore wind farm.

2a.3.16 In 2010 a Virtual Met Mast (VMM) model was developed by the Met Office using their network of data sources and computational models to give further confidence of the likely wind resource at the site. This confirmed that the wind speed is likely to be in the order of that predicted by the BERR model.

2a.3.17 More information on wind speed and direction is being collected from the met mast that was installed at the Project site in April 2012, as shown in Figure 2a.2.

Figure 2a.2: Installed Met Mast

2a.3.18 By comparing the VMM data and the information being collected from the onsite met mast, greater certainty of the wind resource is being established. Figure 2a.3 shows a wind rose that has been developed by comparing the data sources available. This view will be improved as further onsite data become available.

2a.4 Wind Farm Site Layouts

2a.4.1 In order to maintain the flexibility required to ensure that the Offshore Project is designed to take account of detailed ground investigation and design optimisation work which will be undertaken post-consent, a number of indicative site layouts have been developed and assessed as part of the Rochdale envelope for the Project, and these are shown below. These layouts show two designs based on the maximum and minimum number of turbines proposed, where spacing between the turbines has been maximised, and reduced (making the overall design more compact) and where the layouts are based on orthogonal and hexagonal designs. The designs have been named A-H, and Table 2a.3

presents the parameters of each design. Figures 2a.4 and 2a.5 present potential layouts for 100 and 175 turbines respectively.

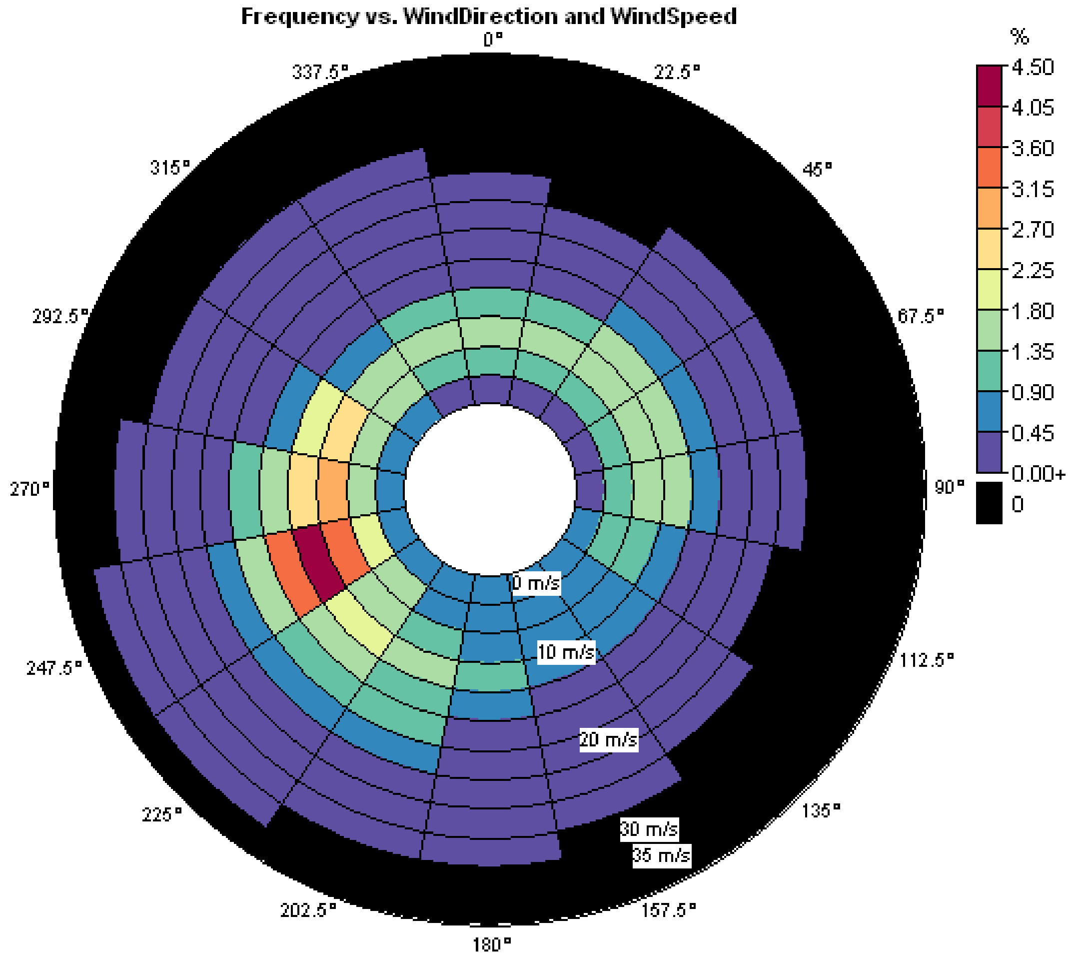


Figure 2.3: Indicative Wind Rose

Table 2a.3: Indicative Turbine Layouts for the Wind Farm

Design	No. of tubines and MW	Full or compressed layout	Layout Style	Spacing between turbines
A	100 X 7MW	Full	Hexagonal	1000m X 1300m
B	100 X 7MW	Full	Orthogonal	1170m X 1170m
C	100 X 7MW	Compressed	Hexagonal	860m X 1150m
D	100 X 7MW	Compressed	Orthogonal	860m X 1150m
E	175 X 4MW	Full	Hexagonal	750m X 1000m
F	175 X 4MW	Full	Orthogonal	880m X 880m
G	175 X 4MW	Compressed	Hexagonal	650m X 850m
H	175 X 4MW	Compressed	Orthogonal	650m X 850m

2a.4.2 The layouts are kept as simple as possible, and will change through detailed design of the Project as it is optimised in light of refined engineering, wind speed and cost data. The turbine layouts are therefore indicative, and solely for the purpose of informing the reader as to the flexibility permitted. They are not illustrative of any probable layout, over and above any other potential permutation within the parameters defined by the Rochdale Envelope.

2a.4.3 The development of the final site layout will take into account the following constraints:

- The Crown Estate Zone Boundary;
- Shipping and Navigation;
- Archaeological Features;
- Geology;
- Fisheries interests;
- Ecology;
- Aggregates extraction areas; and
- Existing redundant cables across the Offshore Project;

2a.4.4 The site layout design will also consider the following factors:

- Optimum wind capture;
- Ground geotechnical conditions;
- Seabed obstructions and munitions;
- Electrical layout (array cables, export cables, offshore substation, etc);
- Water depth;
- Metocean conditions;
- Scour potential;
- Stakeholder considerations (e.g. ornithology, navigation, fishing etc);
- Construction vessel access limitations; and
- Operational access requirements.

The Crown Estate Zone Boundary

2a.4.5 TCE has granted the rights for the development of an offshore wind farm within the Zone. TCE has stipulated a 100m buffer between the Offshore Array boundary and the closest turbine. The Offshore Array boundary is shown in Figure 2a.1.

Existing Cables across the Site

2a.4.6 Two decommissioned telecommunications cables have been identified that run through the Offshore Project area, these being the Brighton-Gibraltar and Cuckmere-Le Havre cables. There may be the possibility of locally removing the cables in the Offshore Project area; however until it is confirmed that they are able to be removed they must be treated as a potential constraint to the Project. Their approximate locations are shown and described in Section 19 - Other Marine Users.

Shipping and Navigation

2a.4.7 The main navigational feature in the vicinity of the Project is the Traffic Separation Scheme (TSS) in the eastern English Channel adjacent to the Dover Strait. This channel is used by a large range of shipping, heading east-west through the English Channel. The nearest shipping lane used by westbound traffic is 4.4 nautical miles from the edge of the Project site. There is an Inshore Traffic Zone (ITZ) north of the TSS, which is used by coastal shipping. In addition, there are aggregate extraction licence areas in the vicinity of, and an area under option agreement partly overlapping with, the Offshore Array; dredging operations in these areas will result in local vessel movements.

2a.4.8 The location of the aggregates extraction interests are shown in Section 19 - Other Marine users, and the area of the Offshore Array that the option agreement partly covers is shown in Section 19 – Other Marine Users (see Figure 19.1). Discussions are ongoing between E.ON and the option holder with regard to the potential for turbines to be sited there. The navigational assessment (Section 14 – Navigation & Shipping) covers the risks of undertaking dredging activities close to any structures should this be necessary.

Archaeological Features

2a.4.9 Known wrecks in and around the Offshore Project site have been shown on the constraints map in Section 13 - Marine Archaeology. An archaeological assessment of the geophysical survey results has been undertaken, and appropriate exclusion zones are proposed around identified archaeological features of interest.

Geology

2a.4.10 The Offshore Project site is located in a shallower area of the English Channel, with relatively gentle seabed slopes. The seabed is predominantly formed of sands and gravels, overlying normally consolidated sands and clays with some peat layers and basal gravels. The strata have been deformed (folded and faulted) and eroded and, as a consequence, the bedrock geology varies across the site. For example, at 30m below seabed only Chalk or London Clay Formation might be encountered at some locations, while at others London Clay Formation, Lambeth Group and Chalk might be encountered.

2a.4.11 The geophysical charts (see Section 6 – Physical Environment) show that a number of submerged valleys (the Northern Palaeovalleys) run north-south and terminate at a shelf, running approximately ENE – WSW in the middle of the site. The shelf has been referred to as an arcuate 'escarpment' which varies between about 100m and 600m wide from top to bottom and in height from about 10m to 14m, its top is broadly delineated by the 30m isobath (below LAT) and its base is between the 38m and 46m isobaths (LAT). The average gradient of the 'escarpment' varies between 0.5° and 9°, meaning that on geotechnical grounds turbine foundations can be located in this area.

Fisheries Interests

2a.4.12 It was noted that there is a relatively high level of commercial fishing activity in the area, particularly potting vessels, gill netting, otter trawling and scallop dredging. Fisheries activities are detailed in Section 18 – Commercial Fisheries.

Ecology

2a.4.13 Potential ecological sensitivities and environmental designations include the presence of MSNCIs which are features of local/ regional interest. There are no sites of national importance - Sites of Special Scientific Interest (SSSI), nor are there any sites of international importance - Special Areas of Conservation (SACs), Special Protection Areas (SPAs) or Ramsar sites within or immediately around the Offshore Project site. Designated sites are considered in detail in Section 19 - Nature Conservation.

2a.4.14 Of the MSNCIs present, one is within the Project site and is known as the *City of Waterford Wreck*. To the west of the Offshore Project site there are two MSNCIs. One is known as the Worthing Lumps (3m high chalk cliffs) lying approximately 8km off the coast of Worthing and 6km to the north-west of the Offshore Project site. The other, Kingmere Reef, close to the western boundary of the Offshore Project site is designated because of the excellent examples of rocky habitats and subtidal chalk outcropping reef systems, as well as the presence of native oysters and black bream nesting sites. To the east of the site, located on the coast to the south-east of Newhaven is South West Rocks (designated due to its vertical chalk cliffs).

2a.4.15 The Marine and Coastal Access Act 2009 created a new type of Marine Protected Area (MPA), called a Marine Conservation Zone (MCZ). These sites will be designated to protect nationally important marine wildlife, habitats, geology and geomorphology. The MCZ project being led by Natural England (NE) and the Joint

Nature Conservation Committee (JNCC) aims to identify and recommend MCZs to the UK government. The team working in the area in which the Offshore Project site is located is called Balanced Seas. The team has recommended to NE and the JNCC two Reference Areas[3] within 10km of the Offshore Project site, these being:-

- Kingmere (rMCZ 16) (4km to the NW of the Project site, and 1.5km to the west of the cable corridor);
- East Meridian (rMCZ 29) located approximately 6.4km to the south and east of the Project site;
- Beachy Head (rMCZ 13) located approximately 12.5km to the west of the Project site; and
- Offshore Overfalls (rMCZ17) approximately 12.5km away from the Project site, to the west/south west.

2a.4.16 NE and JNCC submitted their own recommendations on these sites to Defra in 2012. It is expected that the government will formally designate MCZs in early 2013.

2a.5 Wind Turbines

Turbine Specification

2a.5.1 The exact turbine model and number of turbines will not be known until the final Project design is determined. Turbine technology is continuing to evolve and further monitoring of wind resource and site investigations are required in order to finalise the site design and layout.

2a.5.2 A turbine will be selected in accordance with the parameters set out in the DCO. A range of turbines with a generation capacity of between 3MW and 7MW is being considered, subject to a maximum installed capacity of 700MW and a maximum of 175 turbines. It should be noted that throughout the remainder of the ES the worst-case scenarios mainly relate to the impacts from a 4MW or 7MW layout. With the exception of a slightly smaller rotor diameter, the parameters for a 3MW class turbine are very similar to those for the 4MW class; hence it is considered that the 4MW turbines are representative of the worst case for environmental assessment purposes (height of turbines will directly affect the magnitude of impacts within the seascape, landscape and visual, ornithology, telecommunications and aviation sections).

[3] Draft Guidance from the JNCC on selection of Marine Conservation Zone Reference Areas (version 1.1, Oct 2010) states that "*Each broad-scale habitat type and FOCI [features of conservation importance] should have at least one viable reference area within each of the four regional MCZ project areas where all extraction, deposition or human-derived disturbance is removed or prevented.*"

2a.5.3 The turbine models that are being considered for the Project will typically begin generating electricity at wind speeds of 3m/s rising to the full rated power at 12-14m/s (Table 2a.4); the turbines will typically shut down at wind speeds greater than 25m/s, by feathering the blades out of the wind during these relatively infrequent extreme wind conditions.

2a.5.4 The turbines will have tubular towers that may be assembled in sections. On top of the tower the nacelle is placed, which contains equipment such as the gearbox, generator and other equipment dependent on the turbine model selected. A typical nacelle is shown in Figure 2a.6. The tower is generally constructed in steel and will be between 5 and 7m in diameter at the foundation flange tapering to a diameter of 3 – 4.5m at the top of the tower, depending upon the class of turbine which is being supported.

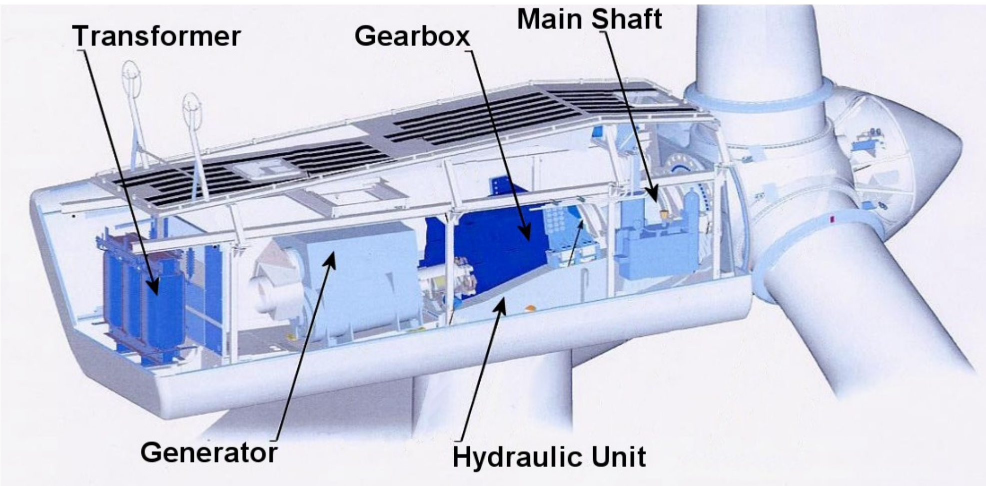


Figure 2a.6: Typical nacelle layout

2a.5.5 The transformer can either be placed in the nacelle or in the tower. It transforms the electricity from low voltage (typically 690V at the generator) to a higher voltage (typically 33kV) for transmission to the offshore substation.

Dimensions and Air Draft Clearances

2a.5.6 An indicative sketch of a wind turbine showing rotor diameter, air draft (blade tip clearance) and hub height is given in Figure 2a.7.

2a.5.7 The Royal Yachting Association[4] (RYA) has recommended that a minimum of 22m should be maintained between sea surface (measured at the highest astronomical tide, HAT) and blade tips. The Maritime and Coastguard Agency (MCA) Marine Guidance Note MGN 371 (2008) recommends that minimum safe (air) clearances between sea level conditions at MHWS and wind turbine rotors are such that they should be suitable for the vessels types identified in the traffic

[4] The RYA's Position on Offshore Renewable Energy Developments: Paper 1 (of 3) – Wind Energy. November 2011http://www.rya.org.uk/SiteCollectionDocuments/legal/Web%20Documents/Environment/RYA%20position%20on%20offshore%20renewable%20energy%20-%20WIND%20-%20Nov11.pdf, accessed 7-Feb-2012

survey, but generally not less than 22m. It is noted that a change from 22m MHWS to 22m above HAT is currently being considered by the MCA and the Nautical and Offshore Renewables Energy Liaison (NOREL) group. The final designs for the Rampion turbines will ensure that such clearance is included.

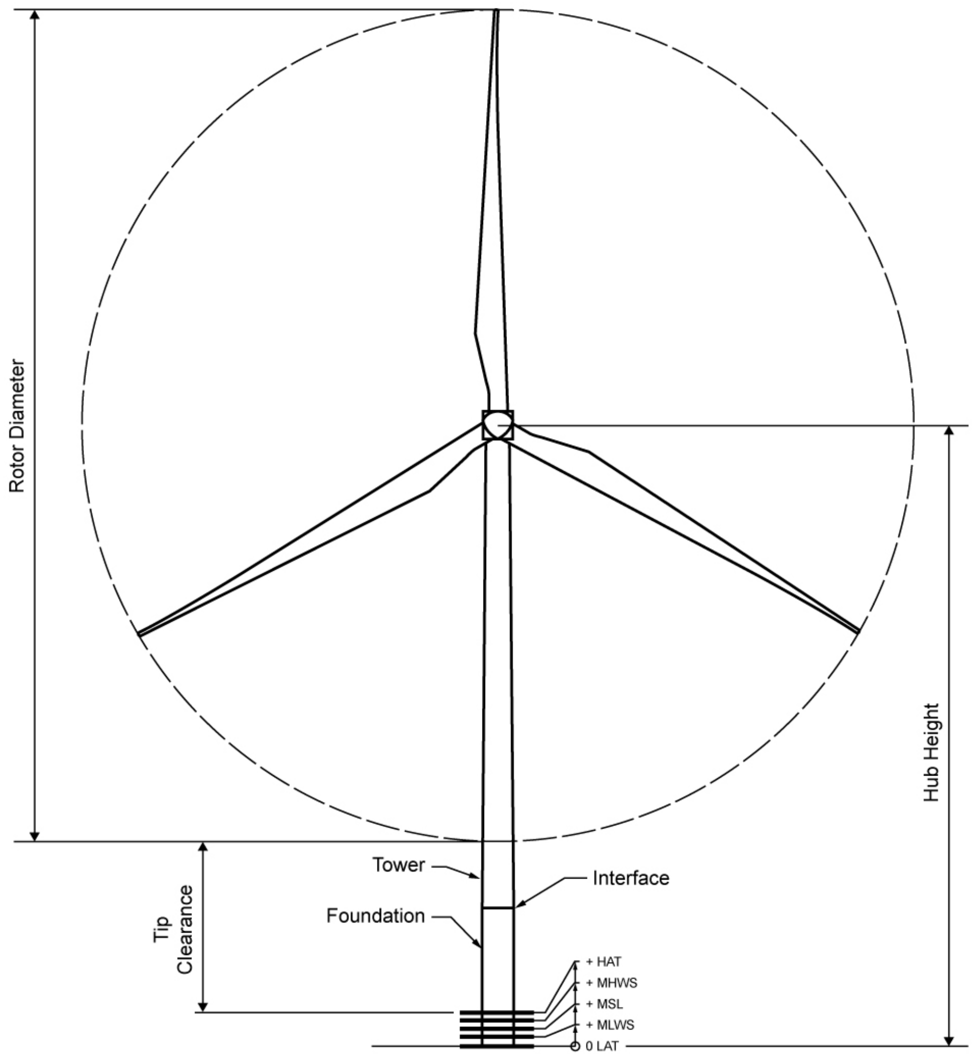


Figure 2a.7: Turbine Air Draft

2a.5.8 Table 2a.4 presents some typical dimensions of the turbines proposed for the Rampion wind farm.

Table 2a.4: Typical Turbine Dimensions

WTG Capacity (MW)	Rotor Diameter (m)	Rotor Swept area (m^2)	Hub Height above Interface (m)	Hub Height above LAT (m)	Tip Height above LAT (m)
4.0	130	13,273	80	100	165
7.0	172	23,235	104	124	210

Colour scheme

2a.5.9 The colour scheme of the turbine tower, nacelle and blades is likely to be light grey RAL 7035, white RAL 9010 or equivalent, except for the lower section of the tower described below.

2a.5.10 The lower part of every wind turbine structure will also be painted high visibility yellow all round, from HAT to a minimum of 15m above HAT (or as high as the Aid to Navigation, if fitted, whichever is higher)[5] (see section 2a.9).

Oils and Fluids

2a.5.11 Dependent on the wind turbine type, the wind turbine will contain the following approximate quantities of mineral lubricating and hydraulic oils:

Table 2a.5: Approximate quantities of oils and fluids

Location	Approx. Qty (litres)
Gear Box oil (mineral oil)	750 to 1600
Hydraulic oil	250
Yaw and Pitch motor oil	20
Transformer	100

2a.5.12 The nacelle, tower and rotor will be constructed to contain any leaks from the main components containing oils and fluids.

Rotational Speed and Blade Pitch

Rotational Speed, Blade Pitch and Chord Width

2a.5.13 The rotational speed is expected to be between 4.5 and 14.8 revolutions per minute depending on the turbine considered.

2a.5.14 The pitch of the blades will also be variable. Therefore, based on prevailing wind conditions, the blades will be continuously positioned to the optimum pitch angle.

2a.5.15 The maximum blade chord width[6] varies according to turbine model, ranging from 4.2m up to 5.45m.

Noise from Operating Wind Turbines

2a.5.16 Noise from wind turbines can be separated into two categories:

- Aerodynamic noise which occurs when wind is passing the blades; and

[5] This is a requirement from IALA Recommendation O-139 on the Marking of Man-made Offshore Structures Edition 1, December 2008:
[6] Chord width is the width of a single rotor blade

- Mechanical noise which is from the engineering components of the turbine such as gearbox and generator.

2a.5.17 Noise levels are based on measured noise curves for turbine models where available or on predictions from the manufacturers. For all turbine models under consideration the maximum predicted source noise is 112dB(A) (according to the IEC61400 –11 standard[7]).

Material Requirements

2a.5.18 The typical weight of a wind turbine will be between 542 and 1143 tonnes, depending upon the turbine selected. This comprises:

- Rotor (including blades) – 100 – 115 tonnes in total (comprising fibre glass and steel);
- Nacelle (including hub) – 125 - 390 tonnes, mainly steel; and
- Tower – 317 – 638 tonnes of steel.

Control Functions and Safety Features

2a.5.19 The MCA's Marine Guidance Notice MGN 371 (M+F) provides guidance on requirements for wind turbine control and safety features. E.ON will follow the guidance provided by the MCA for all project activities.

2a.6 Foundations

Introduction

2a.6.1 This section describes the foundation options for the offshore wind turbines and substations. It also describes the transition pieces that sit between the foundation and the wind turbine (which includes an access platform), the amount of seabed which each foundation type would take up, sediment spill values and possible scour protection options.

Foundation Selection Criteria

2a.6.2 The foundation selection for the Project will be influenced by the following factors:

- Type of wind turbine/hub height that will be mounted onto the foundation;
- Water depth variations;
- Soil conditions, including the ability to pile drive and/or drill;

[7] International Standard IEC 61400-11, Edition 2.1. 2006-11 Wind turbine generator systems – Part 11: Acoustic noise measurement techniques

- Metocean conditions;
- Dynamic wind and wave loading especially with respect to fatigue;
- Installation limits with respect to crane capacities, piling, drilling equipment, etc.;
- Transportation and logistics;
- Material and manufacturing costs and limits;
- Wind turbine access and maintenance requirements;
- Extent of local scour and global seabed movements;
- Cable entry; and
- Decommissioning strategy.

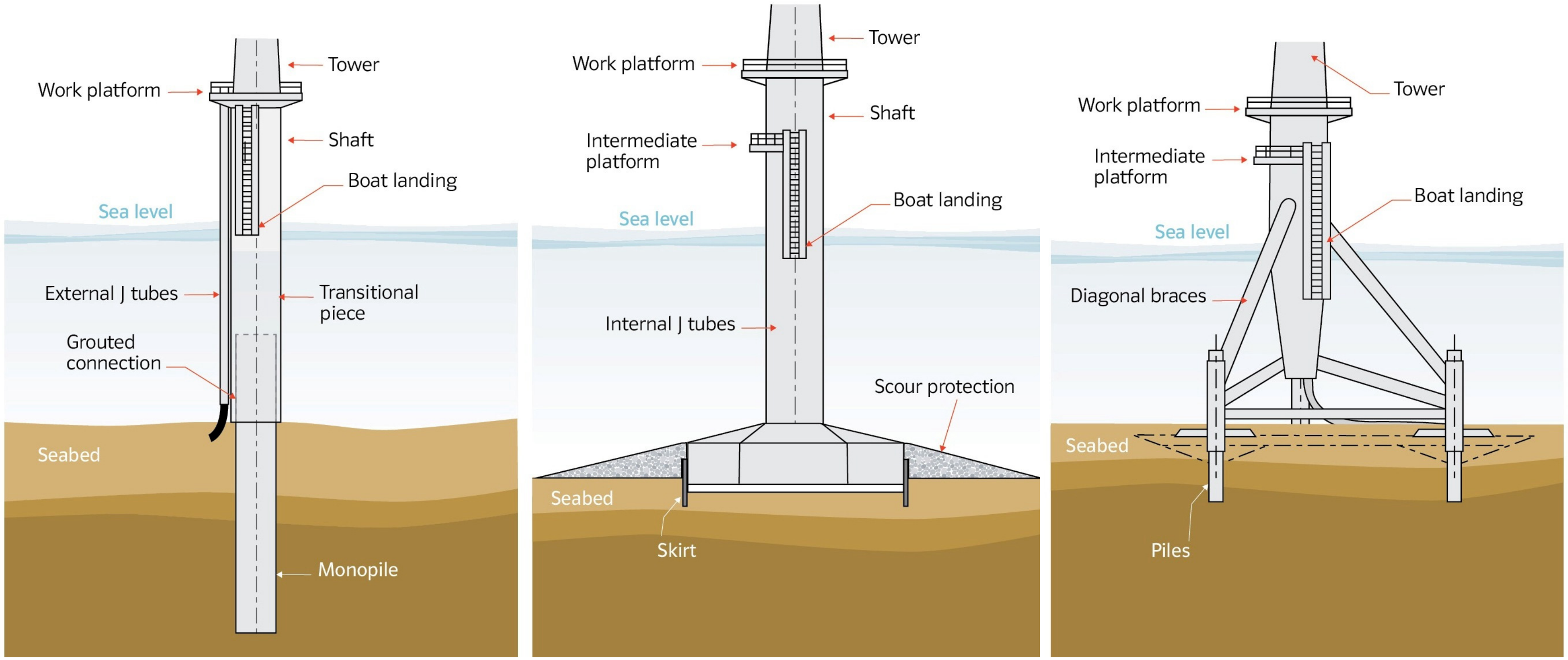
Foundation Types

2a.6.3 The selection of the foundation type will primarily be based upon the site conditions combined with the turbine that is selected. The following foundation types are being considered:

- Monopile;
- Jacket;
- Inward Battered Guide Structure (IBGS) Jacket;
- Tripod;
- Gravity Base; and
- Suction Caisson/Bucket.

2a.6.4 Illustrations of the various types of foundation under consideration are shown in Figure 2a.8.

2a.6.5 The range of water depths present across the Offshore Project site (together with variable geological conditions) indicate that there may be more than one foundation type required for use in the Project. Following on from detailed geotechnical investigations across the site, foundation engineering design studies will assess the alternative types of foundation solutions that will be suitable for the different areas of the site.



Monopile **Gravity Base** **Tripod**

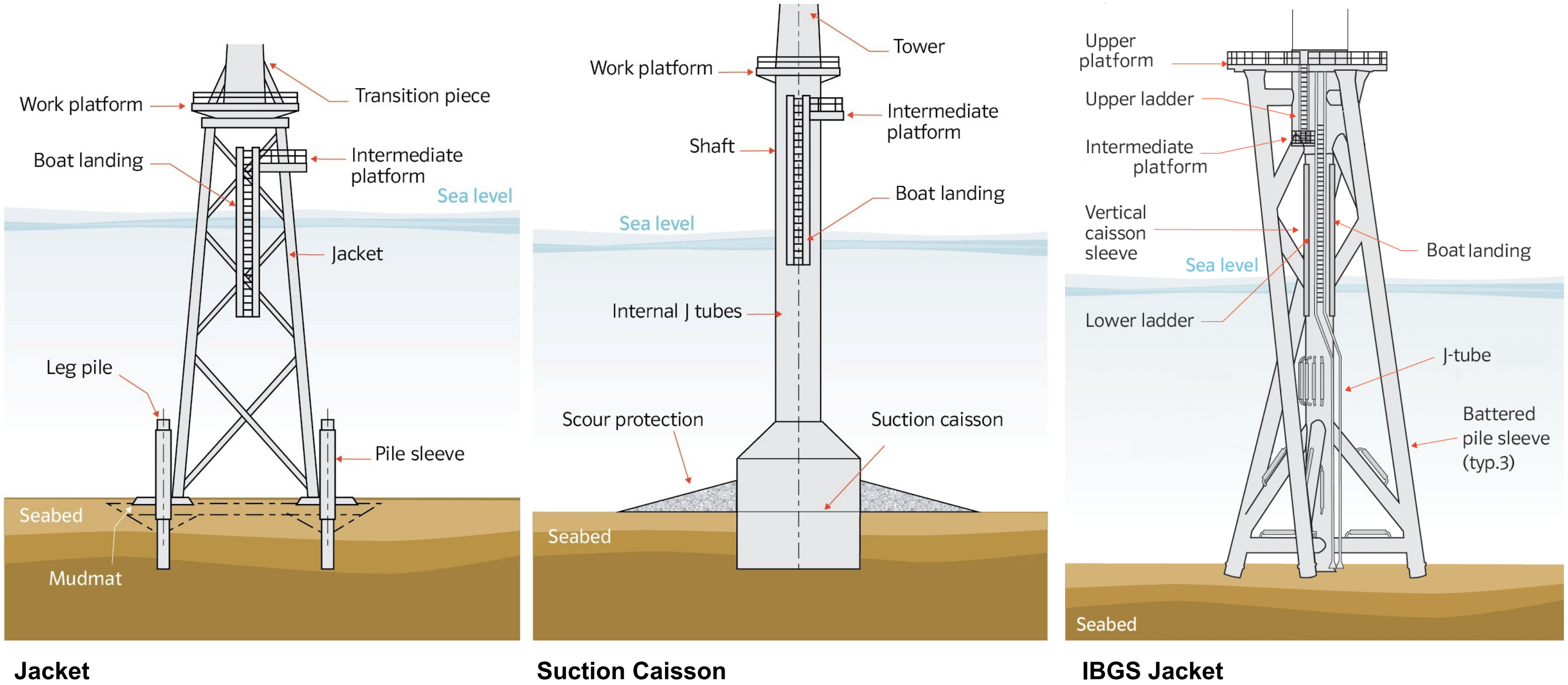


Figure 2a.8: Turbine Foundation Types

2a.6.6 In the sections that follow, each foundation type is considered in relation to each of the following parameters:

- General description;
- Indicative dimensions;
- Manufacturing;
- Material requirements;
- Seabed preparation;
- Transportation and installation;
- Scour protection;
- Sediment spill; and
- Noise levels expected during installation.

Monopile Foundations

2a.6.7 In the UK, the steel monopile is the most common foundation type used for offshore wind turbines. They consist of a single, large diameter hollow steel pile that relies on the soil to provide lateral resistance to loading.

2a.6.8 In the most common version of the concept, steel monopiles are driven into the seabed from a jack-up barge, using a hydraulic hammer which is available in various capacities, for either operation above or below the water surface.

2a.6.9 An alternative installation method includes drilling to assist piling operations. Drilling may be applied where ground conditions make driving impossible or difficult.

2a.6.10 The ‘drive, drill, drive’ methodology has been used successfully on North Hoyle offshore wind farm site amongst others. The basic steps of this methodology include:

- Driving the monopile down to an obstruction layer;
- Drilling out pile internals (diameter of drill is approximately 10-20% less than internal of monopile) to just below the obstruction layer or final pile depth; and
- Driving the monopile to its final depth.

2a.6.11 Figure 2a.9 shows a drill being deployed for the installation of piles at the North Hoyle offshore wind farm.

Figure 2a.9: Drilling operations during monopile installation at North Hoyle

2a.6.12 Monopile foundations have generally increased in size in line with the increasing scale of wind turbines. Typical indicative monopile foundation parameters for the range of wind turbines under consideration (where applicable) are shown in Table 2a.6.

Table 2a.6: Indicative Monopile foundation dimensions

Description	WTG Capacity	
	3 - 4MW	5 – 7MW
Pile Diameter (external)[8]	5.5m	6.5m
Pile penetration depth (below seabed)	45m	55m
Transition piece diameter at sea surface	5.8m	6.8m
Scour Protection volume	2,600m^3	4,700m^3
Scour Protection area	900m^2	1,600m^2
Sediment Spill volume (if drilled)	1,068m^3	1,824m^3

2a.6.13 The foundations are pre-fabricated onshore; steel plates are delivered from steel mills to fabricators who roll and weld the plates together into a tubular monopile structure.

[8] NB, if smaller turbines are installed using monopiles in deeper water, the diameter of the monopile may be larger than would be the case in shallower water. For noise assessment purposes the maximum pile diameter of 6.5m has been used for all modelling

2a.6.14 A transition piece consisting of a piece of steel pile equipped with a flange at the top will either be grouted on the outside of the top of the steel pile allowing it to be adjusted until the top flange is perfectly horizontal, or alternatively a heavy flange might be in place on the monopile during the driving sequence. Typical transition piece weight may vary between 220 and 500 tonnes. Appurtenances such as boat landings, j-tubes and platforms are attached to the transition piece.

2a.6.15 To maintain suitable operational conditions for the combined foundation and wind turbine structure, scour protection (typically consisting of rock aggregate or stone/ concrete mattresses) may need to be installed. Although it will be preferable to design a structure that does not require scour protection, this is not always achievable. The requirement for scour protection will be determined during the detailed design phase and will require a detailed knowledge of the ground conditions and the wave and current climate on site. The typical amounts that may be required per foundation are noted in Table 2a.6.

2a.6.16 Typically scour protection comprises various size grades of rock or stone aggregate or concrete mattresses placed on the seabed surrounding the foundation. Alternative solutions such as fronde mats or sand/concrete filled bags may also be used for scour protection.

2a.6.17 Generally, seabed preparation is not required although some removal of obstructions on the seabed may be required.

2a.6.18 Monopile foundations can be transported to site using the following methods:

- Sealing the ends and floating out to the installation vessel;
- Transporting out on a transport barge or vessel and offloaded on site by crane from a separate installation vessel;
- Transporting the foundations out directly on an installation vessel that can either be of the jack-up or floating crane type.

2a.6.19 Once on site the piles are lifted up by a crane on the installation vessel and held in place until driven into the seabed to their required design depth.

2a.6.20 It is estimated that on average it will take a day to install a monopile foundation. Figure 2a.10 shows a jack-up barge installing a monopile at the London Array wind farm site.

2a.6.21 Driving of monopiles is not expected to create any sediment spill of significance. However, if the ground conditions require the pile to be drilled into position there will be sediment spill. Spoil is typically allowed to return to the seabed naturally in the vicinity of the piling operation.

2a.6.22 The drilled hole would be approximately the internal diameter of the monopile and could run from the seabed to the installed depth of the monopile. however, the drilling could be curtailed just below the obstruction.

Figure 2a.10: Monopile installation at London Array

2a.6.23 The amount of sediment created for the installation will be the volume of sediment drilled out of each pile (if required at all) and can be calculated using the following formula:

$$Volume(m^3) = \frac{\pi \times Diameter(m)^2}{4} \times Length(m) \times no.piles$$

2a.6.24 Thus, for a 6.5m external diameter monopile foundation with 55m penetration, the maximum total volume of sediment displaced would be 1,824m^3.

Gravity Base Foundations

2a.6.25 A gravity base foundation is a large diameter steel, concrete or steel and concrete combination foundation which sits on the seabed to support the turbine tower. The gravity base relies on the weight of the structure to ensure that horizontal loads will not cause any upward forces on the base, which will therefore remain in contact with the seabed. Downward forces are resisted by the base bearing onto the seabed. Additional weight (in the form of ballast) may be added to the foundation once it has been placed into position on the seabed.

2a.6.26 Detailed geotechnical investigations will determine areas where the seabed conditions are suitable for gravity foundations. The gravity foundation may be equipped with a steel skirt penetrating into the seabed below the bottom of the base (depending on ground conditions). This skirt will help to overcome variations in the seabed level beneath the foundation and may also help to reduce scour.

2a.6.27 Table 2a.7 shows indicative parameters for a typical gravity base foundation for a 4MW turbine and a 7MW turbine (to illustrate the overall range) in either 20 or 30m water depth below LAT.

2a.6.28 The foundations would be pre-manufactured onshore where they may be loaded on transport barges for storage at a suitable facility. Some designs are self-buoyant for ease of deployment to the wind farm location when required. If manufactured in the UK, then consideration will be given to the provision of a temporary concrete casting facility local to the construction port.

Table 2a.7: Indicative Gravity base foundation dimensions

Description	WTG Capacity	
	3 - 4MW	5 - 7MW
Indicative Diameter of Gravity Base	29m	34m
Indicative Diameter of Central Tubular stem	5.5m	6.5m
Indicative Height of Gravity Base Slab	9m	10m
Scour Protection volume	5,400m³	10,600m³
Scour Protection area	4,100m^2	7,900m^2
Sediment Spill volume (seabed preparation)	1,100m³	1,820m³

2a.6.29 Prior to the installation of gravity base foundations the seabed may have to be prepared by locally levelling the site. This could involve excavating and installing imported material on the seabed. The amount of material to be excavated and deposited would be determined during the detailed design stage, based upon information from detailed geophysical and geotechnical investigations at each foundation location, however worst-case estimates are provided in Table 2a.7.

2a.6.30 The installation of the gravity base foundations is likely to be carried out from a vessel or they may be floated out to the Offshore Project site and located on the seabed. Figure 2a.11 shows a barge installing gravity base foundations.

2a.6.31 The requirement for any scour protection will be determined following engineering studies and will consider the design of the structure in combination with the wave, currents and geology on site. This is discussed further in Section 6 - Physical Environment.

2a.6.32 The method of scour protection will generally be to use rock armour or other large size aggregate placed around the periphery of the base plate. However, other methods of scour protection as mentioned in 2a.15 above, may also be used.

Figure 2a.11: Barge installing gravity foundations

Jacket Foundations

2a.6.33 The jacket foundation has been extensively used in the oil and gas industry for offshore platforms for many years. There are currently two offshore wind farms in the UK which have used jacket foundations, the Beatrice and Ormonde projects, and as projects go into deeper waters the use of jackets will become more prevalent. The concept consists of a steel lattice structure construction above seabed, and a number of pin piles driven to secure the jacket to the seabed. There are a number of different designs of jacket foundations that are possible:

- A three or four legged jacket solution; this has three or four pin piles installed, one at each corner of a lattice structure; and
- A braced monopile solution; this has a larger single pile driven into the seabed that is supported by a number of smaller piles acting as bracing for the main structure

2a.6.34 It is likely that a jacket solution would be assembled at or near a construction port (either in the UK or abroad). The fabrication of the component parts may take place at a number of separate locations and then be transported to a port location for assembly. Indicative jacket foundation parameters are shown in Table 2a.8.

2a.6.35 Transportation methods are similar to those of monopiles; the foundations will either be picked up directly at a quayside using the installation vessel or transported to site on a barge or another vessel where they will be unloaded onto an installation vessel or directly installed from the barge

2a.6.36 At site the jacket structure is installed by either pre-driving the pin-piles using a hydraulic hammer into the seabed through a template and then installing the superstructure over the pre-installed piles; or by placing the superstructure on the seabed and driving the piles through the structure itself. Once driven the piles are fixed to the piled sockets normally by grouting. Seabed preparation is not usually required for jacket installation.

Table 2a.8 Indicative Jacket foundation dimensions

Description	WTG Capacity	
	3 - 4MW	5 - 7MW
Width of jacket at seabed	14m	20m
Diameter of main tubular	1.2m	2.3m
Number of piles per jacket	4	4
Pin Pile Diameter	1.5m	2.6m
Pile penetration depth (below seabed)	36m	46m
Scour Protection volume	500m^3	3,100m^3
Scour Protection area	400m^2	1,200m^2
Sediment Spill volume (if drilled)	254 m^3	976 m^3

2a.6.37 The requirement for the use of scour protection will be determined in a similar fashion to all other foundation types with calculations being based on the interaction of the sea and seabed with the structure being placed on it. The methods of scour protection will be similar to those discussed in 2a.15.

2a.6.38 Piling of a jacket foundation could take up to 1 day for each pile depending on the complexity of the geology and weather.

2a.6.39 The noise levels during installation of a jacket foundation will be lower than for monopile installation, due to the decrease in pile diameter. However, the duration of noise will be longer (as there are more piles). Section 2a.6.79 presents a summary of expected noise levels from installation of a range of foundation types.

2a.6.40 The driving of pin piles for jacket foundations is not expected to create any sediment spoil of any significance. However, if the ground conditions require the piles to be drilled into position there will be some spoil. Such natural soil arisings emanating from inside the piles will be typically allowed to return to the seabed naturally in the vicinity local to the foundation.

Inward Battered Guide Structure (IBGS) Jacket Foundations

2a.6.41 The IBGS Jacket foundation is an inward battered guide structure that has been developed by Keystone Engineering Inc in the USA. It consists of a vertical central pile (caisson) secured to the seabed as in a monopile design. A prefabricated pile guide structure is then placed and grouted into position over the central caisson.

Smaller diameter piles are introduced into the three inward battered legs in the guide structure and the piles driven into the seabed to their design depths. The piles are grouted to the legs to complete the foundation.

2a.6.42 It is likely that the foundation would be manufactured at a fabrication facility and assembled at a construction port (either in the UK or abroad). The fabrications of the component parts may take place at a number of separate locations and then be transported to a port location for assembly.

2a.6.43 The installation requires a larger diameter central pile to be pre-installed onto which the jacket is lowered. Three smaller piles are then piled through the outer legs of the jacket.

2a.6.44 To maintain suitable conditions for the combined foundation and wind turbine structure, scour protection may need to be installed. The requirement for scour protection will be determined during the detailed design phase and will require a detailed knowledge of the ground conditions and the wave and current climate on site.

2a.6.45 As a worst case, the estimated total volume of scour protection per IBGS jacket would be 1,359m^3.

2a.6.46 Driving of piles for the IBGS jacket foundations is not expected to create any sediment spoil of significance. However, if the ground conditions require the piles to be drilled into position there will be some spoil. Such soil arisings emanating from inside the piles will be typically allowed to return to the seabed in the vicinity local to the foundation.

2a.6.47 The worst case total volume of sediment per IBGS jacket on the Project site would be 390m^3.

2a.6.48 Indicative IBGS jacket foundation parameters are shown in Table 2a.9.

Table 2a.9: Indicative IBGS jacket foundation dimensions

Description	WTG Capacity	
	3 - 4MW	**5 - 7MW**
Diameter of outer piles	1.3m	1.5m
Pile penetration depth (below seabed)	40m	33m
Diameter of central pile	2.2m	2.8m
Central pile penetration depth (below seabed)	30m	35m
Scour Protection volume	700m^3	1,359m^3
Scour Protection area	200m^2	300m^2
Sediment Spill volume (per foundation)	273m^3	390m^3

Tripod Foundations

2a.6.49 A tripod foundation involves three piles driven into the seabed that support a large fabricated structure with a central column that forms the connection to the wind turbine.

2a.6.50 Installation of the tripod involves positioning it on the seabed, with piles then being positioned in the pre-installed pile sleeves. The piles are then driven or drilled into the seabed. Once the pile is installed the annulus between the pile sleeve and the pile is grouted. Grout seals, which are typically made of rubber, prevent grout from escaping during the curing process.

2a.6.51 Alternatively the piles maybe pre-installed using piling template with the tripod lowered into position onto the pre-installed piles. Once the foundation is fixed the transition piece and turbine tower can be installed onto the top of the central column.

2a.6.52 The tripod foundation draws on the experiences gained in the oil and gas industry where light weight and cost efficient three-legged steel jackets have been used for marginal offshore fields.

2a.6.53 The advantage of the tripod is that it is suitable for greater water depths while at the same time it does not require seabed preparation at the site before installation. Typical parameters of a tripod structure are provided in Table 2a.10.

Table 2a.10: Indicative Tripod foundation dimensions

Description	WTG Capacity	
	3 - 4MW	5 - 7MW
Main Column Diameter	3.5m	4.5m
Pile Diameter	2.6m	2.8m
Pile penetration depth (below seabed)	30m	40m
Scour Protection volume	2,500m^3	2,700m^3
Scour Protection area	900m^2	1,000m^2
Sediment Spill volume (per foundation)	477m^3	739m^3

Suction Caisson Foundation

2a.6.54 A suction caisson concept is based on a structure comparable to an upturned bucket that is lowered to the seabed. The combination of the weight of the foundation and the hydrostatic pressure on the caisson when internal water is pumped out of the caisson provides the force required for the bucket structure to penetrate the surface sediments to a depth of typically 8 to 20m. Once installed a suction caisson foundation acts in a similar way to a gravity base foundation, using a large effective mass to resist the overturning moment while bearing directly onto the seabed. However, the structure of the suction caisson itself is much lighter.

2a.6.55 A central column rises from the suction caisson to the surface and typically ends with a flange to which the turbine tower is connected, as the installation method should remove the need for a transition piece.

2a.6.56 This embedment is either achieved through pushing or by creating a negative pressure inside the caisson skirt: both of these techniques have the effect of securing the caisson into the seabed.

2a.6.57 The suction caisson is normally constructed from steel and would be completely prefabricated onshore prior to site delivery. Manufacturing options are the same as for jacket foundations.

2a.6.58 Prior to the installation of suction caisson foundations the seabed may have to be prepared by levelling the site. The amount of material to be moved will be based upon information from the detailed geotechnical investigations, with a worst-case estimate being removal of sediment to a depth of 1m beneath the caisson.

2a.6.59 Installation is expected to comprise lowering the structure onto the seabed by either a crane or release of air from ballast tanks. Once on the seabed, the suction caissons would be secured by removing the water from inside the caisson, creating negative pressure inside the caisson, forcing the caisson down onto the seabed. It is estimated that installation could take from two to three days per foundation.

2a.6.60 A suction caisson foundation may require some scour protection but it would not be of the same order as a gravity base foundation due to the fact that a caisson penetrates 6-9m into the seabed. The basic method of protection is use of rock or armour stone around the periphery of the base plate. Protection would be anticipated out to a distance similar to the diameter of the base plate, extending from the outer edge of base plate perimeter.

2a.6.61 Indicative parameters of the suction bucket foundation are provided in Table 2a.11.

2a.6.62 Other than possible seabed surface levelling, the installation process does not result in the generation of sediment arisings.

2a.6.63 The noise level during installation is expected to be insignificant.

Scour Protection

2a.6.64 Scour of the seabed occurs when the soil particles are displaced by the speed-up of water movement around a structure due to the obstruction it provides. Scour can occur around any structure placed on the seabed and it manifests itself by the formation of scour holes immediately around the obstruction and extending outwards.

Table 2a.11: Indicative Suction Caisson foundation dimensions

Description	WTG Capacity	
	3 - 4MW	5 – 7MW
Diameter of Caisson Base	25m	35m
Scour Protection volume (per pile)	7,900m^3	15,400m^3
Scour Protection area	4,400m^2	8,700m^2
Penetration depth (below seabed)	6m	7m
Sediment Spill volume (seabed preparation)	491m^3	962m^3

2a.6.65 The severity of scour depends on the wave and current velocities at the site (seabed mobility), the type of soil (sand is more likely to scour than clay due to its granular structure) and the size and shape of the obstruction.

2a.6.66 There are two main design options to address seabed erosion:

- Allow for scour in the design (where possible); or
- Install scour protection (usually post installation[9]), such as rock dumping.

2a.6.67 Allowance for scour in the design will lead to increases in penetration depths and potentially increase the wall thickness of the foundation (in the case of monopiles). However, in some cases the additional cost of post installation scour protection and repairs over time outweighs the cost of designing to cope with the anticipated level of scour.

2a.6.68 Where scour protection is installed around the base of the foundations, any of the following solutions could be used:

- Loose rock or stone;
- Concrete mattresses;
- Grout or sand-filled bags; or
- Fronde mats

2a.6.69 Fronde mat scour protection has been installed around the Rampion Met Mast monopile foundation. The effectiveness of this solution will be monitored to assess its suitability for the wind turbine foundations.

[9] A layer of scour protection material (filter layer) can also be placed on the seabed before the foundation is installed. This is subsequently topped-up with larger stones (armour layer) after the foundation is installed.

2a.6.70 The final choice of scour protection can only be made after detailed design of foundations, taking into account a range of aspects including soil data, tides, depth of water, seabed mobility, foundation type, maintenance strategy and the cost of the options. Scour protection may also be installed around the cables leading up to the J-tubes.

2a.6.71 Rock armour installation may involve a specialised rock placement vessel. Once the vessel has positioned itself at the correct location the hydraulically operated dozer blades pushes the rock material over the ship's side or down a chute. Alternatively rock is transported to site by barge where it is then grabbed and dropped into position by an excavating bucket (either positioned on same barge or separate installation vessel).

2a.6.72 Concrete mattress installation involves the precast mattresses being transported to site on the installation vessel, whereby they are picked up and lowered onto location around the base of the foundation.

2a.6.73 The integrity of the installation needs to be regularly monitored by survey and/or inspection of scour protection. Maintenance of scour protection may require periodic installation of additional material.

Summary of key parameters for the foundation options being considered

2a.6.74 Final selection of the foundation types to be used for the Project will determine the levels of various parameters which are important in the consideration of impacts. The following paragraphs present summary information on the worst–case scenarios being considered for the following:

- Loss of seabed area (from scour protection);
- Volumes of sediment spill;
- Influence of foundation type on seabed hydrodynamics;
- Impediment to fishing or navigation activities; and
- Likely noise levels from installation of piles.

2a.6.75 The loss of seabed area for the various foundation options is shown in Table 2a.12 and Table 2a.13. The table provides an estimate of the area of foundation and scour protection area combined for particular foundation types. Where there are several piles as part of a foundation, this has been accounted for in the column providing the area of seabed covered.

Table 2a.12: Seabed area take including scour protection for various foundation options for 3-4MW turbines

Foundation Type	Pile/ foundation diameter (m)	No. of piles	Area of seabed covered including scour protection (m^2) [per foundation]	Rank of seabed take – worst case [per foundation]
Monopile	5.5	1	900	3
Gravity Base	29	0	4,100	2
Jacket	1.5	4	400	4
IBGS Jacket	1.3+2.2	3+1	200	5
Tripod	2.6	3	900	3
Suction Caisson	25	1	4,400	1

Table 2a.13: Seabed area take including scour protection for various foundation options for 5-7MW turbines

Foundation Type	Pile/ foundation diameter (m)	No. of piles	Area of seabed covered including scour protection (m^2) [per foundation]	Rank of seabed take – worst case [per foundation]
Monopile	6.5	1	1,600	3
Gravity Base	34	0	7,900	2
Jacket	2.6	4	1,200	4
IBGS Jacket	1.5+2.8	3+1	300	6
Tripod	2.8	3	1,000	5
Suction Caisson	35	1	8,700	1

2a.6.76 The ground conditions at Rampion are variable across the site. Not all foundation types will be suitable in all locations for the range of turbines. An assessment has been made based upon the currently available geophysical and geotechnical information, of realistic numbers and locations of particular foundation types for the 175 and 100 turbine layouts that would give rise to the worst case seabed take. This is presented in Table 2a.14.

Table 2a.14: Worst case total seabed area take (including scour protection) for the 175 WTG and 100 WTG layouts

Foundation Type	175 turbine layout No. of foundations	Seabed take (m^2)	100 turbine layout No. of foundations	Seabed take (m^2)
Monopile	68	61,200	-	-
Suction Caisson	27	118,800	18	156,600
Gravity Base	80	328,000	40	316,000
Jacket	-	-	42	50,400
Total Seabed Take	-	**508,000**	-	**523,000**

Temporary seabed area take

2a.6.77 Installation of foundations, transition pieces, nacelles and turbine blades are expected to take place using a jack-up vessel. At this stage of the project it is not possible to confirm which, of a relatively limited range, of jack-up vessels will be used to install the Rampion wind farm, the selection is subject to vessel availability and/or the construction contractor selected. While details can not be confirmed, for illustrative purposes dimensions of the jack-up footprint of *MPI Discovery* are presented in Table 2a.15. The Discovery is on a long-term charter to E.ON, and it may therefore be used in the construction of Rampion; however, it should be reiterated that this can not be confirmed at this stage.

2a.6.78 The *Discovery* has six legs, each of which terminates in a 'spud can' or pad (those on the *Discovery* measure approximately 7.5 x 10.0m). These contact the seabed and are used to 'jack up' the vessel. The spud cans will embed into soft seabed sediments, although the degree to which this occurs will be dependent on local ground conditions. Each turbine may require up to three separate deployments (i.e. the vessel placing the spud cans and jacking up) to install each turbine (i.e. the foundation, transition piece, tower, nacelle and blades). Based on a worst-case scenario of 175 turbines, the maximum seabed area that could be impacted by spud cans is 236,399 m^2 (0.237km^2).

Table 2a.15: Area temporarily impacted by jack-up vessel feet

Factor	Total seabed footprint	
	m^2	km^2
Area of spud can (7.5 x 10.0 m)	75	0.000075
Number of spud cans on jack-up vessel (6)	450	0.00045
Number of spud can deployments per turbine (3)	1,350	0.00135
Maximum number of turbines (175)	236,250	0.23625

Sediment Spill

2a.6.79 During the installation of the foundations, there may be a requirement to drill some of the piles or to locally excavate the seabed to prepare it to receive the foundation, this will result in the generation of arisings. These arisings, or sediment spill, will be deposited next to the foundations. The worst case scenario for arisings generation needs to be calculated in a similar way to the scour protection. Table 2a.16 and Table 2a.17 present the maximum sediment spill per foundation type.

Table 2a.16: Worst case sediment spill expected for various foundation types for 3-4MW turbines

Foundation Type	Pile/ foundation diameter (m)	No. of piles	Volume of sediment spill (m^3) [per foundation]	Rank of sediment spill – worst case [per foundation]
Monopile	5.5	1	1,068	1
Gravity Base	29	0	1,100	1
Jacket	1.5	4	254	3
IBGS Jacket	1.3+2.2	3+1	273	3
Tripod	2.6	3	477	2
Suction Caisson	25	1	490	2

Table 2a.17: Worst case sediment spill expected for various foundation types for 5-7MW turbines

Foundation Type	Pile/ foundation diameter (m)	No. of piles	Volume of sediment spill (m^3) [per foundation]	Rank of sediment spill – worst case [per foundation]
Monopile	6.5	1	1,824	1
Gravity Base	34	0	1,820	1
Jacket	2.6	4	976	2
IBGS Jacket	1.5+2.8	3+1	390	4
Tripod	2.8	3	739	3
Suction Caisson	35	1	962	2

2a.6.80 Taking into account the variability of site ground conditions, an assessment has been made based upon the currently available geophysical and geotechnical information, of realistic numbers and locations of particular foundation types for the 175 and 100 turbine layouts that would give rise to the worst case sediment spill. This is presented in Table 2a.18.

2a.6.81 Since it is unlikely that drilling or seabed preparation will be required at each foundation location an expected value of 10% of the total has been assumed to be the worse case sediment spill for each layout scenario.

Effects on seabed hydrodynamics

2a.6.82 The type of turbine foundations to be used has a bearing on the levels of potential change to the natural seabed hydrodynamic regime across the wind farm site. Foundations with a greater profile above the seabed will create the greatest effect on hydrodynamics, Table 2a.19 presents a ranking of the effect that different foundation types for a 3-4MW turbine could have on the hydrodynamic regime, while Table 2a.20 presents similar information for 5-7MW turbines.

Table 2a.18: Worst case sediment spill for the 175 WTG and 100 WTG layouts

Foundation Type	175 turbine layout		100 turbine layout	
	No. of foundations	Sediment spill (m^3)	No. of foundations	Sediment spill (m^3)
Monopile	68	72,080		
Gravity Base	80	88,000	40	72,800
IBGS jacket	27	7,371	18	7,020
Jacket	-	-	42	40,992
Total volume sediment spill	-	**167,451**	-	**120,812**
Expected volume of sediment spill (10% of total)	-	**16,745**	-	**12,081**

Table 2a.19: Worst case hydrodynamic effects from various foundation types for a 3-4MW turbine

Foundation type	Rank of influence
Gravity base	1
Suction Caisson	2
Tripod	3
IGBS jacket	4
Monopile	5
Jacket	6

Table 2a.20: Worst case hydrodynamic effects from various foundation types for a 5-7MW turbine

Foundation type	Rank of influence
Gravity base	1
Tripod	2
IGBS jacket	3
Jacket	4
Monopile	5
Suction caisson	6

2a.6.83 Given the variability in ground conditions across the wind farm site gravity bases would not be applicable throughout. An assessment has therefore been made based upon the currently available geophysical and geotechnical information, of realistic numbers and locations of particular foundation types for the 175 and 100 turbine layouts that would give rise to the worst case effects on hydrodynamics. This is presented in Table 2a.21.

Table 2a.21: Worst case hydrodynamic effects for the 175 WTG and 100 WTG layouts

Foundation Type	175 turbine layout	100 turbine layout
	No. of foundations	No. of foundations
Gravity Base	80	40
Monopile	95	60

Effects on fishing or navigation activities

2a.6.84 The type of turbine foundations to be used has a bearing on the levels of restriction to fishing activities and to general navigational movement through the wind farm site. Foundations with more piles close to the water surface will create the greatest potential for vessel collisions and greater potential for entanglement of nets will arise for foundations with more pile-work on the seabed. Table 2a.22 presents a ranking of the effect that different foundation types for a 3-4MW turbine could have on fishing and general navigation, while Table 2a.23 presents similar information for 5-7MW turbines.

Table 2a.22: Rank of worst case numbers of piles close to the sea surface and close to the seabed for various foundation types for both 3-4 and 5-7MW turbines

Foundation Type	No. of piles	Rank of potential disruption
Jacket	4	1
IBGS Jacket[10]	3+1	2
Tripod	3	3
Monopile	1	4
Suction Caisson	1	5
Gravity Base	0	6

2a.6.85 Using the limitations on usage of foundations and currently available geophysical and geotechnical information an assessment has been made of realistic numbers and locations of particular foundation types for the 175 and 100 turbine layouts that would give rise to the worst case in terms of potential disruption to fishing and navigation activities. This is presented in Table 2a.28.

2a.6.86 Vessels are generally expected to keep a safe distance away from the foundations. Hence the risk of entanglement of fishing nets and collision with underwater elements of the foundations should be low.

[10] The standard jacket is ranked above the IGBS jacket in this case as the IGBS jacket is based on 3 smaller piles being located around a central pile, while the jacket has a wider structure at the sea surface

Table 2a.23: Worst case numbers and types of foundations for disruption to fishing and navigation activities from the installation of foundations for 175 and 100 turbine layouts

Foundation Type	175 turbine layout No. of foundations	100 turbine layout No. of foundations
Jacket	80	82
Monopile	68	
IBGS Jacket	27	18

Noise from the installation of foundations

2a.6.87 The type of turbine foundations to be used has a bearing on the levels and duration of temporary noise impact which will arise during the construction period. The foundation type (or types) will be determined based on a number of factors, primarily bathymetry, turbine size, seabed geology and wind and wave loading on the structure.

2a.6.88 Noise levels are principally generated from the need to perform 'percussion piling' of cylindrical steel piles into the seabed. They are a function of the following factors: pile diameter, pile wall thickness, hammer energy, site geology (which as a consequence dictates the amount of energy required to drive the pile) and the noise propagation properties for the selected site, which includes bathymetry (DOW, 2009).

2a.6.89 Of these factors it is the overall diameter of the pile that has the greatest influence on the source level of the noise. Highest source noise levels during installation would be generated from installation of monopile foundations (as they have the greatest diameter of any pile being considered). The largest diameter monopiles are likely to be designed for a 6MW turbine.

2a.6.90 A worst-case scenario for source noise levels can be calculated in a similar way to the scour and spill arisings. Table 2a.24 ranks the highest source noise levels which are likely to be generated from each foundation type being considered for the 3-4MW turbines, while Table 2a.25 presents the same information for the 5-7MW turbines.

2a.6.91 Monopile foundation designs are currently only suitable for use in depths of up to 30m, therefore another foundation design is expected to be required to support those turbines in deeper water. Studies are currently ongoing in the wind industry to increase the range of water depths and loads for the use of monopile foundations.

Table 2a.24: Rank of worst case noise source levels expected for various foundation types for 3-4MW turbines

Foundation Type	Pile/ foundation diameter (m)	No. of piles	Rank of source level
Monopile	5.5	1	1
Tripod	2.6	3	2
IBGS Jacket	1.3+2.2	3+1	3
Jacket	1.5	4	4
Suction Caisson	25	1	5
Gravity Base	29	0	6

Table 2a.25: Rank of worst case noise source levels expected for various foundation types for 5-7MW turbines

Foundation Type	Pile/ foundation diameter (m)	No. of piles	Rank of source level
Monopile	6.5	1	1
Tripod	2.8	3	2
IBGS Jacket	1.5+2.8	3+1	3
Jacket	2.6	4	4
Suction Caisson	35	1	5
Gravity Base	34	0	6

2a.6.92 Certain geological and loading conditions may indicate a different foundation type even in depths less than 30m, however, a worst case for the purposes of noise assessment would be to assume all turbines which could potentially be sited in water depths less than 30m, will use monopiles. The worst case in terms of number of foundations being piled, and overall cumulative period of noise, would be the 175 turbine layout scenario.

2a.6.93 Using the limitations on usage of foundations and currently available geophysical and geotechnical information an assessment has been made of realistic numbers and locations of particular foundation types for the 175 and 100 turbine layouts that would give rise to the worst case regarding highest source levels of noise. This is presented in Table 2a.26.

Table 2a.26: Worst case numbers and types of foundations for source noise levels from the installation of foundations for 175 and 100 turbine layouts

Foundation Type	175 turbine layout No. of foundations	100 turbine layout No. of foundations
Monopile	95	60
Jacket	80	40

2a.6.94 To date in the UK the vast majority of wind turbines installed offshore (over 500 turbines at the end of 2011) have utilised monopiles and a well-established range of mitigation techniques has been developed to ensure safety of other sea users and to limit as far as practicable the impact on marine mammals and fish. These include the use of exclusion zones, 'soft start' piling techniques, guard boats with marine mammal observers on board, and in some cases avoidance of certain periods during the year where required due to seasonal ecological sensitivities.

2a.6.95 'Soft start' is the term used for the slow increase in blow energy used when installing piles. For the largest monopiles the ramp up time between the commencement of piling and the maximum blow energy being used is typically in the order of 30 minutes. The noise contours presented in the noise modelling report (Appendix 8.6) relate to maximum blow energies required for each pile size, not to the blow energies used when the piling process commences. It should be noted that a single monopile was successfully installed in the Project site in April 2012 to support the meteorological mast, blow energies used to complete this installation were much lower than had been envisaged as a worst-case.

2a.6.96 In addition to consideration of the worst-case in terms of highest source levels, the other worst-case scenario relates to the absolute number of piles which need to be installed. The 4MW turbine layout option, which will require 175 turbines is the worst case in terms of numbers of foundations required. As the jacket and IBGS jacket foundation options could be used to support 4MW turbines in all depths of water, and each have four piles per foundation, either could be considered the worst-case. However, because the central pile of the IBGS jacket has a greater diameter than those proposed for the jacket foundation, use of the IBGS jacket foundation for all 4MW turbines is considered to be the worst-case in terms of the greatest number of piling operations.

2a.6.97 A worst-case scenario for duration of noise generating activities (pile installation) can be calculated in a similar way to the highest source noise levels. Table 2a.27 ranks the longest duration of noise generating activities which are likely from each foundation type being considered for the 3-4MW and 5-7MW turbines.

Table 2a.27: Rank of worst case "duration of piling noise" expected for various foundation types for both 3-4 and 5-7MW turbines

Foundation Type	No. of piles	Rank of duration of piling
IBGS Jacket[11]	3+1	1
Jacket	4	2
Tripod	3	3
Monopile	1	4
Suction Caisson	1	5
Gravity Base	0	6

2a.6.98 Using the limitations on usage of foundations and currently available geophysical and geotechnical information an assessment has been made of realistic numbers

[11] For the IBGS (the central caisson pile would be installed first, followed by the IBGS structure itself, then the three smaller diameter raking piles)

and locations of particular foundation types for the 175 and 100 turbine layouts that would give rise to the longest duration of noise generating (piling) activities. This is presented in Table 2a.28.

Table 2a.28: Worst case numbers and types of foundations for duration of piling noise from the installation of foundations for 175 and 100 turbine layouts

Foundation Type	175 turbine layout No. of foundations	100 turbine layout No. of foundations
Monopile	68	-
IBGS Jacket	27	18
Jacket	80	82

Transition Pieces

2a.6.99 Transition pieces are likely to be used to connect the wind turbine tower to the foundation. The transition piece provides a means to adjusting non-verticality tolerances of installed foundations.

2a.6.100 The transition piece, which does not undergo significant loading during installation, can be equipped with electrical equipment and appurtenances (e.g. boat landings, J-tubes, work platforms, etc) prior to offshore installation.

2a.6.101 There are two main methods of connecting the transition piece to the foundation:

- Grouted joint: The transition piece is joined to the foundation with a radial connection of high performance grout, which is typically cement based and has an initial curing time of 8 to 12 hours. The tower is then mounted on a flange on top of the transition piece; and
- Bolted flanged connection – welded in-situ or pre-installed.

2a.6.102 There are other possible methods of installing the transition piece to the foundation; however the above are the two most likely methods of achieving this.

2a.6.103 One of the alternatives to using a transition piece is the use of a flange welded directly onto the foundation. This option has the potential of a reduction of offshore vessel time as well as saving on grout curing time. However, damage of the flange or high fatigue of the flange is a latent risk for piled foundations.

2a.7 Offshore Substation

2a.7.1 There will be up to two offshore substations installed to serve the development. The substations are expected to be located within a 2km wide band bordering the northern boundary of the Offshore Array, as this is technically preferable.

The exact locations, design and visual appearance will be subject to a structural study and electrical design, which is expected to be completed post consent.

2a.7.2 The offshore substations will be installed on jacket, monopile or gravity base foundations, similar to those described for the turbines themselves. Each offshore substation will be placed on top of the foundation (approximately 20m above LAT) and is expected to have an area of approximately 2,000m^2 with plan dimensions of up to 45m by 45m and a topsides height of up to 25m. The total weight of each substation is expected to be between 1,200 to 1,800 tonnes.

2a.7.3 The total height of each substation including the foundation will be up to 45m above LAT. The substation topsides will either be clad or will be unclad with exposed painted steelwork. The substations will be marked for navigational purposes in accordance with MCA and Trinity House requirements.

2a.7.4 Each offshore substation is expected to include the following key components:

- Two medium to high voltage (HV) transformers;
- Auxiliary transformers and low voltage switchboards;
- HV (132kV to 220kV) Gas Insulated Switchgear (GIS);
- Medium voltage (33kV) switchgear;
- Diesel generator and diesel storage tank;
- Control and SCADA rooms;
- Batteries;
- Emergency accommodation (It is unlikely that the substation will be permanently manned);
- Workshop and stores;
- Helipad or heli-hoist area; and
- Davits and cranes for maintenance.

2a.7.5 All electrical equipment and other key components will be installed into the substation topsides during the fabrication process and pre-commissioned onshore. The completed topsides will be transported offshore on a barge or a suitable jack-up vessel. A heavy lift crane vessel or jack-up with a large capacity crane on-board will be used to lift the topsides into position on to their pre-installed foundations (see Figure 2a.12).

Figure 2a.12: Installation of offshore substation at the London Array Offshore Wind Farm

2a.7.6 Following installation of the topsides the export and array cables are pulled through the J-tubes (fixed to the substructure) into the cable deck and connected to the substation electrical equipment. The final commissioning of the substations can then take place.

2a.7.7 Each HV transformer will contain approximately 40,000 litres of oil and the diesel tank will hold up to 10,000 litres of fuel. Each item of equipment that contains oil will be bunded with an open steel bund which will be capable of holding more than the total volume of fluid for the equipment contained within the tank.

2a.8 Cables

Inter-Array cables and layout

2a.8.1 The inter-array cabling will connect each of the turbines in a radial or ring network arrangement to the offshore substations. Ringed network arrangements provide redundancy in the event of a cable failure and allow auxiliary supplies to turbines be maintained.

2a.8.2 The number of turbines connected on each radial or ring depends on a number of factors:

- The generation capacity of each turbine on the network;
- Cable sizes available;

- The distance between turbines;
- The distribution voltage; and
- The design philosophy (e.g. inclusion of redundancy).

2a.8.3 Typically for a radial network there will be between six and eleven turbines on each string.

2a.8.4 The distribution system (inter-array cables) is likely to operate at a nominal voltage of 33kV, however alternative system voltages of up to 72.5kV (operating voltage of 66kV) may be considered during the design stages of the project.

2a.8.5 The cable type will most likely be a three-core, armoured cable with copper or aluminium conductors and XLPE (cross-linked polyethylene) or EPR (ethylene propylene rubber) insulation. The cable will have integrated fibre optic unit for communication purposes. An image of a typical 33kV cable is presented in Figure 2a.13.

Figure 2a.13: Cutaway of a 33kV three core copper XLPE subsea power cable

2a.8.6 The array cabling will be designed in such a way to minimise the amount of cable installed; however it is important that the layout allows enough space around each foundation for other construction vessels (e.g. jack-up barges) to operate safely.

2a.8.7 The route of the cabling around the foundations will allow for the cables to be pulled up the foundation structure. The cables may run past the foundation and then loop into their final position; this allows additional length in the cable for any changes in the seabed and prevents cables becoming too taut.

2a.8.8 Each of the two substations will have between 8 and 12 strings, depending on the turbine selection and the cables used. The routing of the cables will consider environmental constraints (e.g. fish spawning grounds, reef areas) and any identified wrecks on the site and will also avoid geological features highlighted in the site investigations. The total length of array cables for the 700MW development will be approximately 230km.

2a.8.9 The inter-array cables will typically be buried at a target burial depth of 1m below the seabed surface. The final depth of the cables will be dependent on the seabed geological conditions and the risks to the cable (e.g. from anchor drag damage). It is anticipated that an area of around 10m in width will be disturbed around the cables as they are installed.

Subsea export (transmission) cables

2a.8.10 The export cables will connect the offshore substations to the shore. They are likely to be armoured and have three core cables with copper conductors and XLPE insulation, at a voltage of between 132kV and 220kV. The cross-section of a typical 132kV XLPE insulated three copper core export cable is shown in Figure 2a.14. The cables will also contain fibre-optic cores that will be used for protection, control and communications systems.

2a.8.11 Some typical dimensions for three-core, XLPE insulated, export cables with steel wire armour with voltages of 132kV, 150kV and 220kV are provided in Table 2a.29. To transmit the power to shore it is expected that four export cables will be required if the full 700MW is constructed. Current (amps) carried by the cables will reduce for the higher voltage cables if the same level of power is exported from the array (as power is related to voltage multiplied by current).

2a.8.12 The maximum operating temperature of the offshore cables will be 90°C. However, the temperature will be lower than this when the wind farm is not operating at full capacity.

Route Corridor for the subsea export Cables

2a.8.13 The export cable corridor runs from the north of the Offshore Array to the shore and varies in width ranging from 12.4km at the wind farm boundary to 580m at the shore. The four cables will be installed with a separation distance of at least 50m (except at the beach crossing and on approach to the offshore substations) due to installation and repair requirements, the maximum route lengths will be 23km per cable. The co-ordinates for the export cable corridor are presented in Table 2a.30 and shown in Figure 2a.1. The cable routes will lie within this corridor.

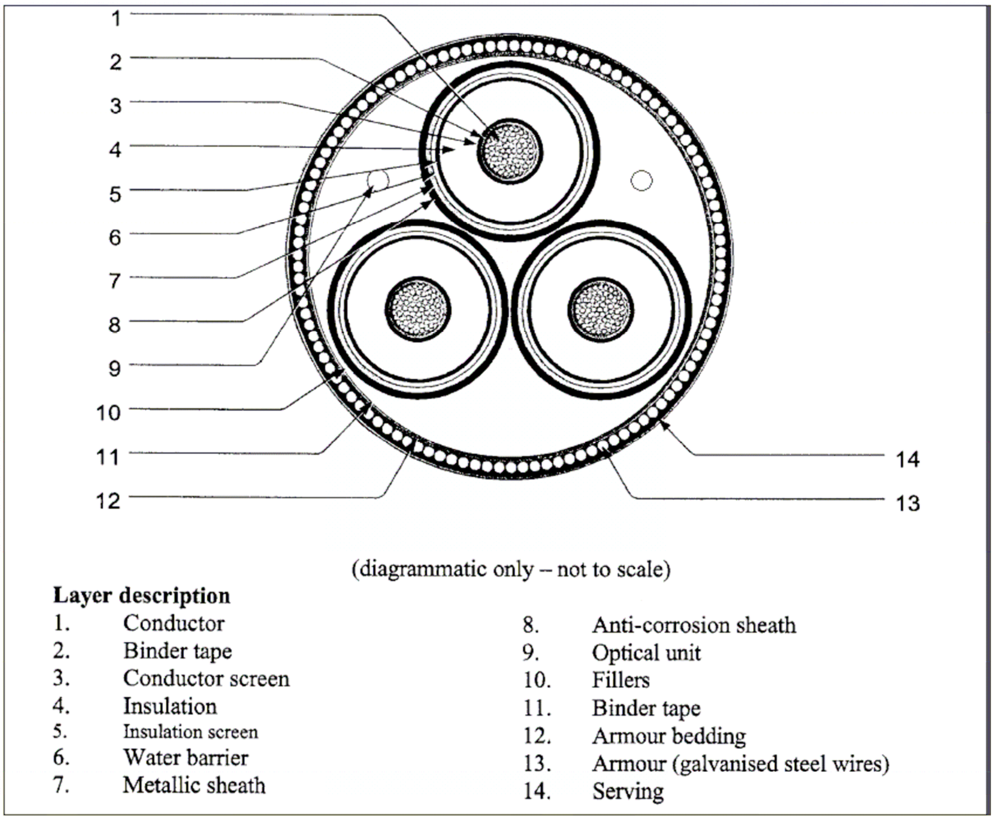


Figure 2a.14: Cross-sectional Diagram of 132kV three core copper/XLPE cable

Table 2a.29: Examples of 132, 150 and 220kV export cable parameters

Working voltage	132kV	150kV	220kV
Number of cores	3	3	3
Conductor Material	Copper	Copper	Copper
Conductor cross section	1,000mm^2	1,000mm^2	1,000mm^2
Overall Diameter	206mm	215mm	241mm
Weight in air	95kg/m	100kg/m	115kg/m
Weight in seawater	70kg/m	74kg/m	85kg/m

Table 2a.30: Cable corridor co-ordinates

Co ordinate	Longitude	Latitude
A	50.689751	-0.343816
B	50.706896	-0.229361
C	50.695252	-0.167537
D	50.753184	-0.244257
E	50.818269	-0.315861
F	50.815449	-0.328936
G	50.817659	-0.331672
H	50.815881	-0.337865
I	50.812993	-0.336175
J	50.808510	-0.348785
K	50.755157	-0.328995

2a.8.14 The required width of the export cable route and installation corridor will vary along the length of the cable route and will depend upon water depth, geotechnical and environmental constraints and other considerations (e.g. such as the need to loop the cable to effect repairs, if required). A pair of export cables will be routed from each offshore substation within separate corridors approximately 100m wide. These corridors will converge to form a single corridor of approximately 300m width at a point between the Offshore Array and the Landfall. The width allows for the potential need to allow cables to deviate from the preferred parallel laying that is proposed, in the event that seabed obstructions are encountered. It is expected that a seabed area of around 10m in width will be disturbed during installation of the export cables. A total construction width of up to 700m may be required to allow for the anchor spreads of cable installation vessels.

2a.8.15 Table 2a.31 presents a calculation of the total seabed area which could be affected by installation of the inter-array and export cables. In addition to the area of seabed affected by installation of the cables, it is estimated that in a worst case scenario up to 10% of the routes may need to be protected using armour stone or mattressing, resulting in changes to approximately 0.32km^2 of seabed area during wind farm operation.

Table 2a.31: Estimated realistic worst-case scenarios for area of seabed loss during installation of the offshore cables

Cable	Maximum Length	Width of seabed affected	Total area affected
Inter array	230km	10m	2.3km^2
Export cables	4 x 23km	10m	0.92km^2
Total			3.22km^2

2a.8.16 A geophysical survey was carried out in 2010 between the Offshore Array area and the preferred cable Landfall option; preliminary geotechnical investigations were completed in May 2011. Following a review of this information, the export cable corridor has been refined. The following environmental, engineering and construction considerations were taken into account in refining the corridor:

- Anchoring area for Shoreham harbour – encroachment of the corridor into this area has been reduced;

- Substation locations – these are expected to be located within a 2km wide band bordering the northern boundary of the Offshore Array.

2a.8.17 The final route selection exercise for the export cables will be an iterative process as more site data are collated. The following environmental, engineering and construction considerations will be taken into account in identifying and selecting the export cable route:

- The start and end points of the export cable;

- Avoidance of BAP/Annex I habitats;

- Avoidance of identified wrecks;

- Avoidance of the anchoring area for Shoreham harbour;

- Avoidance of areas of rock outcrop;

- Avoidance of outfall pipe crossings;

- The minimum cable separation will be 50m, except at the beach crossing and on approach to the offshore substations;

- Where possible the route will follow the palaeochannels;

- Where possible the route will avoid areas of high concentrations of boulders and magnetometer contacts; and

- The four cables will be kept in the same general route corridor as far as possible.

2a.8.18 Based on the geophysical survey data, a route clearance activity will be required prior to construction.

2a.8.19 The export cables will typically be buried at a depth of between 1.0m and 2.0m below the seabed surface depending on the ground conditions and the risks of damage to the installed cable (e.g. from vessel anchors).

2a.8.20 Each of the four export cables will be installed separately. Each export cable will be a single 3-core cable without field joints, although the cable may have to be jointed if issues arise during installation. The cable laying operations are dependent on the water depth, met ocean conditions and seabed geology.

Installation of Subsea Cables

2a.8.21 The inter-array cables and the subsea export cables will be installed using one or a combination of the three methods: ploughing, trenching or jetting. It is likely that a combination of these methods will be adopted for localised areas depending on seabed conditions. The installation methods will be selected during detailed design and tendering phases.

Ploughing

2a.8.22 This method involves a blade, which cuts through the seabed and the cable is laid behind. Ploughs are generally pulled directly by a surface vessel or, they can be mounted onto a self-propelled tracked vehicle which runs along the seabed.

2a.8.23 Cable ploughs are usually deployed in simultaneous 'lay and trench' mode although it is possible to use the plough to cut a trench for the cable to be installed at a later date provided the ground conditions are suitable. When installing the cable in simultaneous lay and trench operation the plough may use cable depressors to push the cable into position at the base of the cut trench; as the plough proceeds the trench is back-filled to provide immediate burial. Ploughs can be used in seabed geology ranging from very soft mud through to firm clays but, in general, ploughs are not suited to harder substrates such as boulder clay. Some ploughs are fitted with water jet assist options and/or hydraulic chain cutters to work through patches of harder soils. A typical plough design in shown in Figure 2a.15.

2a.8.24 Ploughing is a one-off process and cannot be repeated to re-bury an exposed cable.

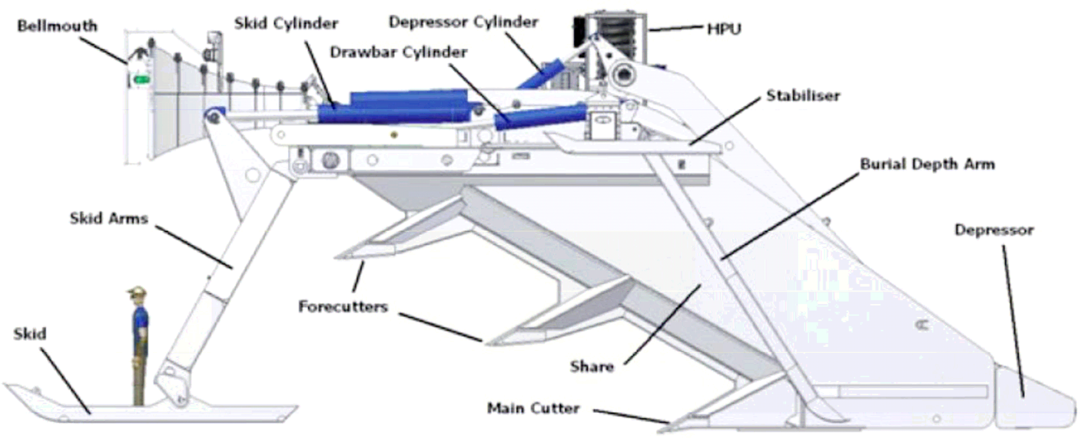


Figure 2a.15: Cable Plough, courtesy of IHC Merwede Engineering Business

Jetting

2a.8.25 This method involves directing water jets towards the seabed to fluidise and displace the seabed sediment. This forms a typically rectangular trench into which the cable generally settles under its own weight.

2a.8.26 The water jets are usually deployed on jetting arms beneath a remotely operated vehicle (ROV) system that can be free-swimming or based on passive skids or active tracks. There are also towed jetting skids available for the installation of cables.

2a.8.27 During the formation of the trench the displaced sediment is forced into suspension and settles out at a rate determined by the sediment particle size, density and ambient flow conditions. The jetting process is not intended to displace sediment to an extent that it is totally removed out of the trench; moreover, it requires that the fluidised sediment is available to fall back into the trench for immediate burial through settling. It is only the finer fractions of sediments that are likely to be held in suspension long enough to become prone to dispersal away from the trench as a plume.

2a.8.28 A key benefit of a jetting tool is that it is able to operate close to structures and it is also possible to use jetting tools for remedial burial if required.

2a.8.29 Typically there are two methods of water jetting available: “Seabed Fluidisation” and “Forward Jetting a Trench”.

Seabed Fluidisation:

2a.8.30 With this jetting method the cable is first laid on the seabed and afterwards a jetting sledge is positioned above the cable. Jets on the sledge flush water beneath the cable fluidising the soil whereby the cable, by its own weight, sinks to the depth set by the operator.

Forward Jetting a Trench:

2a.8.31 In this method water jets are used to jet out a trench ahead of cable lay. The cable can typically be laid into the trench behind the jetting lance.

2a.8.32 An example of the equipment used to jet cables into the seabed is shown in Figure 2a.16.

Trenching

2a.8.33 Trenching involves the excavation of a trench whilst temporarily placing the excavated sediment adjacent to the trench. The cable is then laid and the displaced sediment used to back-fill the trench, covering the cable. This is most commonly used where the cable has to be installed through an area of rock or seabed composed of a more resistant material.

2a.8.34 Trenching is a difficult, long and expensive method to use compared to other methods and would only be used in exceptional circumstances.

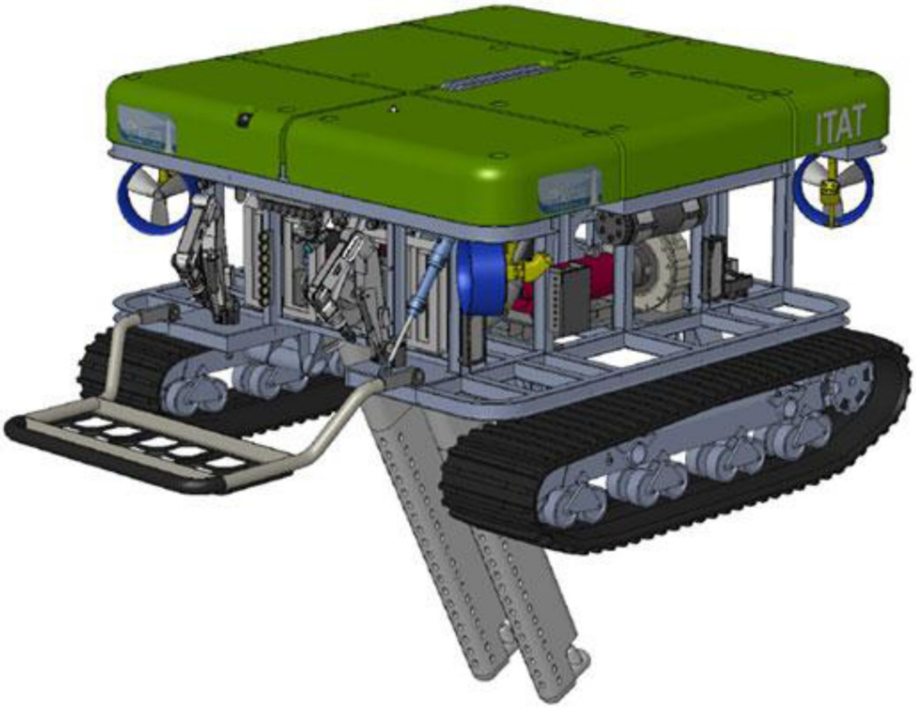


Figure 2a.16: Cable jetting seabed fluidiser, courtesy of Pharos Offshore

Subsea Cable Crossings

2a.8.35 There are two known existing cables lying within the Offshore Project area. Both of these are redundant telecommunications cables. The preferred action for these cables is to remove any sections which intersect with either the foundations, inter array or export cables.

2a.8.36 Should any cable crossings be required a methodology will be produced which considers the detail of the existing cable and the ground conditions.

Cable Landfall

2a.8.37 The offshore export cables will interface with the onshore cables at the transition pits. The transition pit locations will be within the green shaded "HDD section" immediately north of crossing 01-01 as shown on Figure 2b.1 (see Section 2b – Onshore Project Description).

2a.8.38 The exact alignment of the four subsea export cables will not be known until much further into the development process but the Export Cable Corridor within which these will be laid is shown in Figure 2a.1. These export cables will converge to the onshore transition joint bays and cable trenches.

2a.8.39 The four subsea export cable ducts will be drilled underneath the beach and the A259 road using horizontal directional drilling (HDD) techniques (see Section 2b – Onshore Project Description). As part of the HDD operations it is expected that a barge or jack-up platform will be located at the seaward end of the drill for a period of around 10-14 days while each duct is installed. A detailed construction plan for the HDD work will be produced for agreement with the regulatory authorities in advance of work commencing. The plan will specifically address containment of drilling mud (bentonite[12]) during drilling operations.

2a.8.40 Subsequently the four export cables will be pulled shorewards through these ducts by winching equipment stationed north of the A259. The marine cables will remain in the ducts beneath the beach and under the A259. No surface disruption to the road and beach defences is expected to take place, although access to the beach and foreshore would be required by track type machinery to aid in the drilling works and cable pulling activities. It is envisaged that a substantial cabling barge would need to be anchored in the intertidal zone during the cable pulling activities; typically the barge will be on station for around 2-3 days per cable installation.

2a.9 Navigation and Aviation Marking

Introduction

2a.9.1 This section describes the navigation safety features that the Offshore Project will incorporate. Throughout the construction, operation and maintenance of the Project, aids to navigation (AtoN) will be provided in accordance with the Trinity House Lighthouse Services (THLS) requirements, which will comply with IALA standard O-139 on the Marking of Offshore Wind Farms (IALA, 2008).

Wind Turbine Marking System

2a.9.2 Each wind turbine structure will be marked with illuminated identification signs that comply with the requirements in Maritime and Coastguard Agency Marine Guidance Notice MGN 371[13] Annex 5. Each sign will have clearly visible (by both vessels at sea level and aircraft including helicopters and fixed wing from above) unique identification characters at a location that is easily and readily serviceable. The identification characters will each be illuminated by a low-intensity light so that the sign is visible from a vessel thus enabling the structure to be detected at a suitable distance to avoid a collision with it. This will be such that under normal conditions of visibility and all known tidal conditions, they are clearly readable by an observer (with naked eye), stationed 3m above sea levels, and at a distance of at least 150m from the turbine. The light will be either hooded or baffled so as to avoid unnecessary light pollution or confusion with navigation marks.

2a.9.3 In accordance with IALA Recommendation O-139[14] the tower of every wind generator will be painted yellow all round from the level of Highest Astronomical Tide (HAT) to at least 15m above HAT or the height of the Aid to Navigation

[12] bentonite is a naturally occurring clay material
[13] Maritime and Coastguard Agency, "Marine Guidance Notice MGN 371 (M+F) Offshore Renewable Energy Installations (OREIs) – Guidance on UK Navigational Practice, Safety and Emergency Response Issue", Aug-2008, File Ref: MNA/053/010/0626
[14] IALA, "IALA Recommendation O-139 on the Marking of Man-Made Offshore Structures", Ed. 1, December 2008

(AtoN), if fitted, whichever is greater. Alternative marking may include horizontal yellow bands of not less than 2m in height and separation.

Aviation Obstruction Lighting

2a.9.4 The mandated requirement for the lighting of wind turbines generators on UK territorial waters is set out at Article 220 of the UK Air Navigation Order (ANO) 2010. The CAA has issued an associated policy statement entitled "CAA Policy and Guideline on Wind Turbines"[15] which provides additional guidance to the ANO (2009).

2a.9.5 Article 220 of ANO (2010) requires the fitting of obstacle lighting, primarily for night-time use, on offshore wind turbines with a height of 60m or more above HAT. In general, offshore wind turbines of 60m and higher are required to be fitted with aviation obstruction lighting as follows:

- At least one medium intensity steady red light positioned as close as possible to the top of the fixed structure. The Article requires medium intensity (2000 candela) steady red lighting mounted on the top of each nacelle.
- Where four or more wind turbines are located together in the same group, with the permission of the CAA only those on the periphery of the group need be fitted with obstruction lighting.
- The downward spread of light is restricted as far as possible to minimise any potential confusion with maritime lighting whilst maintaining flight safety. Provisions already exist within Article 220 that require the reduction in lighting intensity at and below the horizontal and allow a further reduction in lighting intensity when the visibility in all directions from every wind turbine is more than 5km. All offshore wind turbine developers are expected to comply fully with the requirement aspect and to make full use of the additional allowance that exists within Article 220.

2a.9.6 There is a future possibility that, as opposed to the use of steady lighting, the Article 220 requirement will be interpreted to reflect the use of flashing red lighting, displaying a Morse code "W". It is likely that, if flashing lighting is deemed appropriate, the flash sequence on each turbine within the same wind farm development would be required to be synchronised (i.e. all lighting flashes at the same time).

2a.9.7 The latest aviation legislation, policy and guidelines will be adhered to during the design, construction and operational phases of the Project.

[15] Civil Aviation Authority, Directorate of Aerospace Policy, "CAA Policy and Guidelines on Wind Turbines", CAP 762, Issue date 05/08/2011

Marine Navigational Marking

2a.9.8 The navigational marking and fog horn specifications for the Offshore Project will be agreed with THLS when more information becomes available on the array layout. In the absence of this agreement Marine Guidance Note 371 Annex 2[16] will be considered as follows:

- Consideration will be given to how the overall site would be marked by day and by night, taking into account that there may be an ongoing requirement for marking on completion of decommissioning, depending on individual circumstances;
- How individual structures and fittings on the perimeter of and within the site, both above and below the sea surface, would be marked by day and by night;
- If specific turbines would be inherently radar conspicuous from all seaward directions or would require passive enhancers;
- If the site would be marked by one or more radar beacons (racons);
- If the site would be marked by an Automatic Identification System (AIS) transceiver, and if so, the data it would transmit; and
- If the site would be fitted with a sound signal or signals, and where the signal or signals would be sited.

2a.9.9 The latest navigation legislation, policy and guidelines will be adhered to during the design, construction and operational phases of the Project.

Construction Markings

2a.9.10 During the construction of the offshore wind farm, working areas will be established and marked, where required, in accordance with the IALA Maritime Buoyage System. In addition to this, where advised by THLS, additional temporary marking may also be applied.

2a.9.11 Notices to Mariners, Radio Navigational Warnings, NAVTEX and/or broadcast warnings as well as Notices to Airmen will be implemented in advance of any proposed works.

2a.9.12 All OREI structures will be marked in accordance with 0-139 on The Marking of Man-Made Offshore Structures (IALA, 2008).

Marking of the Wind Farm

2a.9.13 According to IALA Recommendation O-139 a Significant Peripheral Structure (SPS) is the 'corner' or other significant point on the periphery of a wind farm.

[16] Maritime and Coastguard Agency, "Offshore Renewable Energy Installations (OREIs) – Guidance on UK Navigational Practice, Safety and Emergency Response Issues", Marine Guidance Note MGN 317 (M+F), August 2008

Every individual SPS should be fitted with lights visible from all directions in the horizontal plane. These lights should be synchronized to display an IALA 'special mark' characteristic, flashing yellow, with a range of not less than five (5) nautical miles. In the case of a large or extended wind farm, the distance between SPSs should not normally exceed three (3) nautical miles.

2a.9.14 Selected intermediate structures on the periphery of a wind farm other than the SPSs should be marked with flashing yellow lights which are visible to the mariner from all directions in the horizontal plane. The flash character of these lights should be distinctly different from those displayed on the SPSs, with a range of not less than two (2) nautical miles. The lateral distance between such lit structures or the nearest SPS should not exceed two (2) nautical miles.

2a.9.15 The Project will comply with the above recommendations and, for clarity, an indicative marking configuration of a sample wind farm is shown in Figure 2a.17.

2a.10 Construction and Installation

2a.10.1 This section presents possible strategies for construction and installation, including the likely construction vessels, the volume of traffic and the management of the marine logistics.

Overall Construction Vessel Strategy

2a.10.2 Construction of the wind farm can be split into two logistical chains:

1. Delivery of components from supply chain direct to Offshore Project site;
2. Delivery of components and services from supply chain to Offshore Project site via a convenient intermediate port.

2a.10.3 In principle the construction vessels will be determined through contractual negotiations. The likely main vessel types are shown in Table 2a.32 alongside the Project phase to which they are applicable.

Vessel Movements

2a.10.4 Two vessel movement scenarios have been considered:

- 175 x 4MW wind turbine scheme; and
- 100 x 7MW wind turbine scheme.

2a.10.5 Table 2a.33 outlines the primary vessel traffic intensity for the 175 wind turbine design and shows that there will be approximately 1,260 heavy vessel movements over a continuous construction period of approximately three years. This equates on average to 420 per year, or 35 per month.

Table 2a.32: Anticipated construction vessel types

<table>
<tr><th>Project Phase Activity</th><th>Likely Type of Construction Vessels Required for Project Phase</th><th>Support Vessel requirements</th></tr>
<tr><td>Foundations
(2 vessels)</td><td>Jack up vessels and transport barges.
Self-propelled transportation and installation vessels with the capability of carrying at least 5 monopile foundations per trip. New generation deep sea specialist transportation and installation vessels, with or without the capability of jacking and carrying 3 jacket sets per trip.
Small jack up barges to undertake pin pile activities
Crane barges or shear leg cranes</td><td rowspan="5">Tugs
Multiple work boats for cable terminations, equipment and personnel transfers
Local boats for standby / field guard vessels
Dedicated grout spread barge
Multiple commissioning work boats
Anchor handling vessels
Diving spread</td></tr>
<tr><td>Scour Protection
(1 vessel)</td><td>Dedicated construction barge for deployment of scour mattressing or dedicated rock dumping vessel.</td></tr>
<tr><td>Wind Turbines
(1 vessel)</td><td>Installation jack up vessel capable of transporting up to 6 x 4MW turbine sets or 3 x 7MW turbine sets in a single round trip.</td></tr>
<tr><td>Offshore Substation</td><td>Monohull crane lifting barge, shear leg barge or jack up vessels. Transportation barge.</td></tr>
<tr><td>Cable Lay
(3 vessels)</td><td>Dedicated DP2 cable lay vessel for inter array cables. Single adapted construction anchor barge for exports cables.
Remote operated tracked vehicles (ROV).</td></tr>
</table>

2a.10.6 The vessel movements presented in Table 2a.33 are based on a 175 x 4MW turbine site, assuming that 95 of which are installed on monopile foundations with the remainder on steel jackets. The vessel movement estimations assume that up to five monopiles and their transition pieces can be transported on a single vessel from the sub-assembly port direct to the site. It has been assumed that up to three jacket type foundations can be transported in one trip.

2a.10.7 Table 2a.34 outlines the primary vessel traffic intensity for the 100 wind turbine case and shows that there will be approximately 907 heavy vessel movements over a continuous construction period. This equates to an average of 302 per year, or 25 per month over a three year construction period.

2a.10.8 The vessel movements presented in Table 2a.34 are based on a 100 x 7MW turbine site, assuming all are installed on Jacket foundations. It has been assumed that 3 jacket foundations can be transported in one trip and 8 pin piles (two sets) are also able to be transported in a single trip.

Table 2a.33: Primary vessels, marine traffic intensity (175 x 4MW WTGs)

Description	Units per vessel	Approximate movements to/from site	Approximate movements inside site	Comments
Turbines	6	60	150	Complete sets
Foundation monopiles	5	38	76	Assuming 95 turbines on monopiles
Foundation pin piles	8	84	83	2 sets of 4 piles per trip
Foundation - jackets	3	56	83	Excludes pin piles
Scour protection	1-2	354		
Offshore substation	1	8		2 jackets + 2 topsides
Array cables	6	68	192	6 cable reels per trip (3 cables per reel)
Export cables	1	8	4	
Approximate total heavy vessel movements to site		**676**	**588**	

Table 2a.34: Primary vessels, marine traffic intensity (100 x 7MW WTGs)

Description	Units per vessel	Approximate movements to/from site	Approximate movements inside site	Comments
Turbines	3	67	99	Complete sets
Foundation pin piles	8	100	99	2 sets of 4 piles per trip
Foundation - jackets	3	67	99	Excludes pin piles
Scour protection	1-2	204		
Offshore substation	1	8		2 jackets + 2 topsides
Array cables	6	56	115	6 cable reels per trip (3 cables per reel)
Export cables	1	10		
Approximate total heavy vessel movements to site		**495**	**412**	

2a.10.9 In addition to the above there are likely to be further inbound supply vessel movements from cable manufacturers offloading at a local construction marshalling port, and where the pre assembled foundations and other equipment are loaded out onto transportation / installation vessels. The number of transportation vessels utilised at local construction port(s) will depend upon a number of factors including:

- Location and capability of suitable construction port(s);
- Type of installation vessels being used;

- Size and weight of components;
- Distance of manufacturing facility from site; and
- Installation methodology.

2a.10.10 These issues will be jointly determined with the selected contractors. However, Table 2a.35 presents an estimation of the inbound supplier vessel movements to and from the site or to and from the local construction port. The wind turbine and foundation type assumptions are the same as those made for Table 2a.33 and Table 2a.34.

Table 2a.35: Inbound supplier delivery

Description	**Approximate No. of inbound supplier vessel movements**		**Comments**
	175 x 4MW	**100 x 7MW**	
Foundation - monopiles	38	-	Based on 5 per delivery to port
Foundation - pin piles	56	168	Based on 12 per delivery to port
Foundation - jackets	56	78	Based on 3 jackets per delivery
Array cables	82	44	Based on 5 cables per delivery
Approximate total no. of inbound supplier deliveries	**232**	**290**	

Support Vessel Movements

2a.10.11 In addition to the heavy transport vessels there will be a requirement for a number of smaller support vessels undertaking tasks such as:

- Towing barges;
- Cable burial;
- Tug work;
- Survey vessels;
- Anchor Handling;
- Multiple daily work boats for project personnel / equipment transport;
- Standby vessels;
- Guard vessels; and
- Diver spread.

2a.10.12 Table 2a.36 presents the support vessel movements for construction of the Offshore Project either as a 175 or 100 turbine development.

Table 2a.36: Support vessel movements to site for both 175 and 100 turbine development options

Description	Approximate No of support vessel movements to and from port		Comments
	175 x 4MW	100 x 7MW	
Anchor handling	346	178	Based on 2 support vessels for positioning.
Turbine commissioning vessels	878	450	Based on 9 visits per WTG, 8 teams, 2 vessels. Transfer vessel carrying 4x 3 WTG crews per visit
Cable burial vessel	762	390	Small vessels may return to safe haven port on a daily basis (programme assumes 39 weeks duration, 2 vessels)
Survey vessels	196	100	Returns daily, 20 weeks duration, 1 vessel.
Diver spread / vessels	254	130	Likely 26 week duration for inter array work
Guard vessels / security	164	84	Based on 1 round trip per week over 117 weeks, 1 vessel
Work boat / crew transfer	762	390	Based on 1 round trip per day over 39 weeks, 4 teams, 2 vessels.
Approximate total support vessel movements to site	**3,362**	**1,722**	Based over 3 years

Construction Logistics Management and Security

Logistics Management

2a.10.13 One of the critical success factors for the Project is good logistics management during the construction and commissioning phases. It is anticipated that this will be co-ordinated from a project facility at a local port. The facility would provide the construction team a base to ensure co-ordination and management of:

- Port operations including management, marine co-ordination, covered warehousing, open storage, pre assembly and general support to the offshore construction co-ordination and port operations;
- Central supply chain project base;

- HSEQ, emergency response control centre;
- Permit to work system for commissioning/confined space activities;
- Offshore and onshore site security; and
- Limited temporary storage of components to reduce impacts of manufacturer delays and provide a safe storage location during adverse weather conditions.

Safety Zones & Site Security

2a.10.14 Temporary offshore safety zones of 500m will be implemented around each turbine and substation where construction works are taking place to ensure safety during the construction phase, which includes the safety of third party personnel and equipment.

2a.10.15 The safety zone would be subject to a “Notice to Mariners”and the perimeter secured by guard boats, to ensure that third parties do not stray into the temporary construction zone.

2a.10.16 Where necessary, along the export cable route guard / standby boats will be employed to guard specific points of exposure, i.e. unburied sections of newly laid cable, cable crossings before rock dumping protection is laid, divers in water etc.

2a.10.17 Vessels will also be nominated to monitor the safety zone(s) and guard against infringements as this is considered good industry practice.

Local Construction Port Facilities

2a.10.18 The Project supply chain will engage with local port facilities for the following purposes:

- Storage of main components and equipment prior to load out for installation;
- Pre-assembly of equipment (i.e. pre-assembly of nacelle and towers) before being loaded and transported to construction site for installation;
- Load out and support services of foundation assemblies;
- Local construction and commissioning site management; and
- Personnel transfer facility.

2a.10.19 To achieve these objectives, the local construction port would preferably need to comply with the following criteria:

- Local to construction site: the more local to construction site the less time is used in construction and commissioning vessel round trips and crew transfers. There is also less transport risk (navigation, weather, towage etc.) associated with carrying large loads over short distances.

- Quayside access: sufficient quay side access is required as a minimum to take a large construction vessel alongside the quay. Capacity for two vessels would be preferred to enable concurrent loading and unloading operations if required.

- A concrete quayside access is also required with load bearing capacity sufficient to take the load of craneage and the heaviest weight being transferred on or off a vessel. The quayside access needs to have sufficient space to be able to manoeuvre large components such as pin piles, jackets, tower sections and nacelle / blade combinations, array cable handling and miscellaneous installation equipment.

- Storage and assembly area: the port facility should also provide sufficient access to be able to store components delivered from the manufacturers and to pre-assemble if required (before being loaded onto a vessel, the tower, nacelle and blades could be partly assembled onshore on the assembly site and some commissioning performed).

- Ability to complete foundation systems in close proximity to the quay edge.

- Any storage and assembly area should also have direct access and be immediately adjacent to the quayside to avoid transporting large items between lay down areas.

- Generally work to the aim of minimising offshore work during the final erection, it is essential that the port facility is optimised in terms of pre-assembly and site logistics.

- No access restrictions: a port that has no tidal access or draught restrictions for the vessels being used along with no physical entry access restriction from narrow harbour entrances is essential.

- Transportation links: a construction port that has good transport links (rail, road and airport) is preferred enabling personnel and equipment and plant transfer by these means to the port.

- Utility supplies: the construction port needs to provide utilities such as water, power etc. to support project offices, all welfare and canteen facilities and assembly and loading operations.

- Security: the storage, assembly and loading area need to be securable to prevent equipment damage and risk of safety incident due to unauthorised personnel entering the area.

2a.10.20 Given the above, the location and resources of the shore based facility are key factors to the successful construction of the Project. The port location will serve as a control centre for the construction phase, the contractors, subcontractors, project management, coordination, health and safety, environment and support staff.

2a.10.21 The selection of a port for the construction period will be determined during the procurement phase when the final scheme design has been fixed and the full requirements relating to construction logistics are understood, taking account of the supply chain locations.

2a.10.22 An alternative to using ‘local’ construction ports for the main construction vessels is to undertake any pre-assembly and transport equipment, i.e. turbines or foundations, directly from manufacturers local dispatch port or a remote port which could be outside the UK. This option would increase transport time for construction vessels and may impose a higher element of transport risk for pre-assembled components.

Employment Forecast

2a.10.23 This section estimates the number of personnel employed during the construction and commissioning of the Offshore Project based on vessel movement scenarios for the 100 and 175 turbine development scenarios.

Offshore Construction & Commissioning

2a.10.24 Table 2a.37 presents estimates the number of “operational” personnel that will be onboard during each main construction vessel during transportation and installation activities.

Table 2a.37: Main construction vessel personnel requirements

Activity description	No. vessels	Approximate No. of operational personnel on board per vessel (excludes permanent vessel crews)	Total number of personnel
Turbines	1	20	20
Foundations (jacket)	2	30	60
Foundations (jacket pin piles)	1	20	20
Scour	1	10	10
Offshore substation platform	4	20	80
Array cables	2	20	40
Export cables	1	20	20
Approximate total	**12**		**250**

2a.10.25 From the Table 2a.37 it can be seen that approximately 250 persons have been estimated as being required on the main construction vessels (excluding any permanent crew members on each vessel). In practice there may be more than one of these vessel types working on the site at the same time. Also due to 24hr and 7 days a week nature of offshore construction there will probably also be back to back crews that will change over after a period i.e. 2 weeks. It is therefore conceivable to estimate that the actual number of personnel required on the main construction vessels will be doubled to approximately 500.

Commissioning & Support Vessel personnel Requirements

2a.10.26 In addition to the main offshore construction vessels, personnel will also be required for the support vessels. Table 2a.38 gives an estimate of the number of personnel that will be onboard each support vessel, and the total number of commissioning and support personnel that will be required.

Table 2a.38: Commissioning & Support vessel personnel requirement

Activity description	Approximate No. of support vessels required	Approximate No. of operational personnel on board per support vessel	Total No. of personnel
Anchor handling	2	5	10
Turbine commissioning personnel transport	2	12	24
Cable termination teams	2	12	24
Survey vessels	1	6	6
Diver spread	1	12	12
Guard vessels/ security	2	4	8
Crew transfer vessel	4	2	8
Approximate total	**14**		**92**

2a.10.27 From Table 2a.38 it can be seen that a staff of approximately 92 will be required to undertake offshore completions, commissioning and other operations. Similarly to the main construction vessels, it is likely that some of the positions will have back to back arrangements, with crew changes after a period of 2 weeks. On this basis it is estimated that the total number of different personnel employed in this group will be doubled to 184.

Onshore Support

2a.10.28 During the offshore construction phase there is likely to be a support team onshore at any local construction ports to undertake activities such as:

- Supply chain construction / commissioning teams and project management personnel;
- Pre-assembly of turbines for loading onto construction vessels;

- Receive manufacturing loads and load construction vessels for their transport to site;
- Site security and services; and
- Repair / maintenance teams during construction.

2a.10.29 The nature and activity level of the above will depend upon how the Project logistics will eventually be managed and is therefore difficult to estimate at this stage the number of personnel that will be employed in these activities.

2a.10.30 Table 2a.39 presents an estimate of the employment numbers used in onshore support for both development options considered (175 and 100 turbines), including a single local construction support base.

Table 2a.39: Employment numbers for onshore support base personnel

Activity Description	**Approximate No. of Persons Employed**	
	175 x 4MW scheme	100 x 7MW scheme
Construction / Commissioning		
Site construction/commissioning teams and project management	56	29
Pre assemble WTGs for loading onto construction vessels	28	15
Receive manufacturing loads and load construction vessels for their transport to site.	17	9
Operations		
Site security and services	17	9
Offshore repair teams	9	5
Operations and maintenance (generation)	35	18

2a.11 Construction Programme

2a.11.1 The overall construction period for the Project from the commencement of onshore works to completion of commissioning of the wind farm will be approximately 4 years.

2a.11.2 From previous experience in the construction of offshore wind farms, it is estimated that the Offshore Project, is likely to be constructed over a 2½ to 3 year period. Construction of the Onshore Project will take place over 2 years, followed by commissioning. Based on these estimates, an indicative programme for the construction of Rampion Offshore Wind farm is presented in Figure 2a.18.

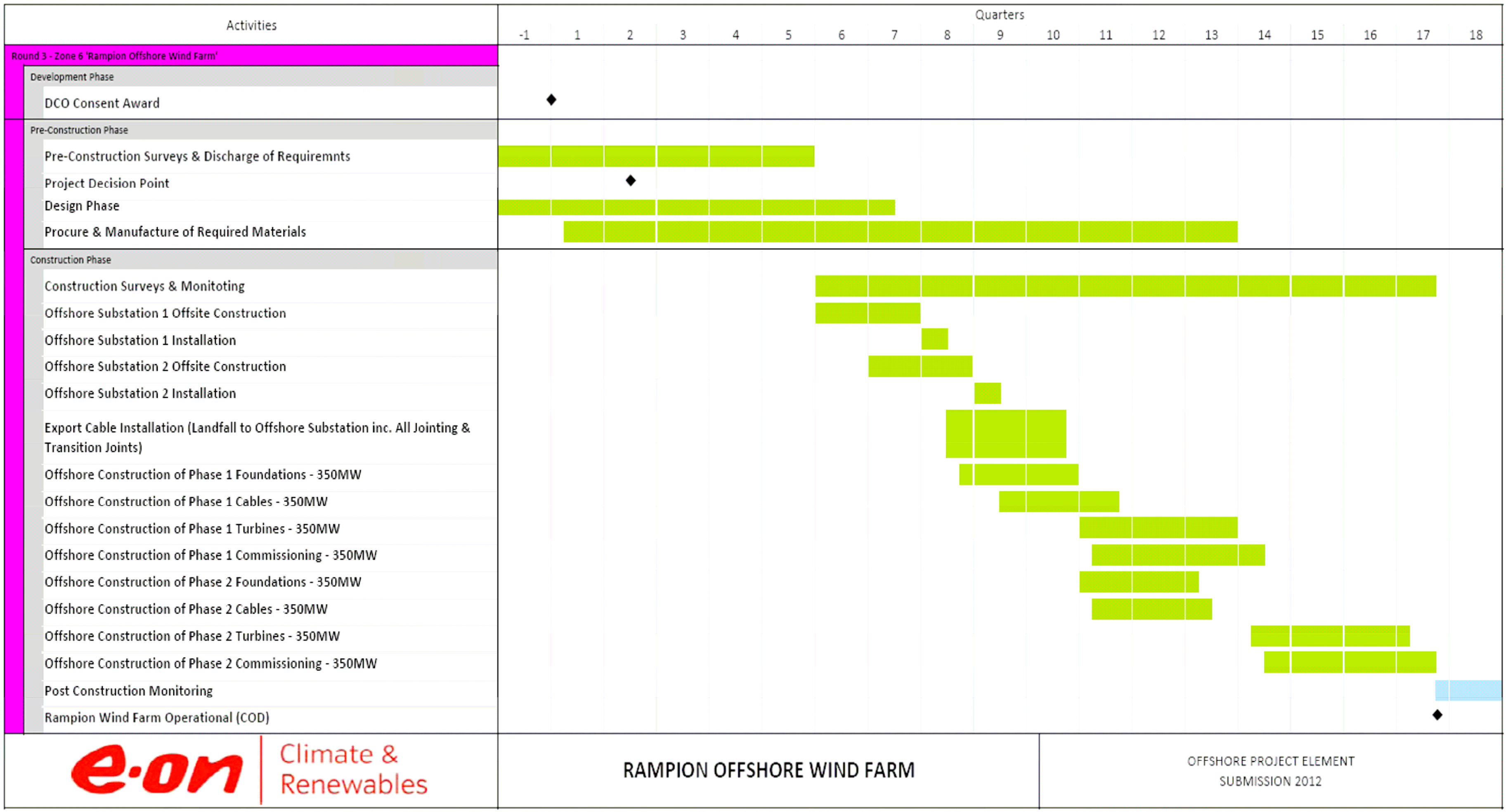


Figure 2a.18: Indicative Construction Programme

2a.11.3 The Indicative programme shows that the offshore works are broken into two phases, which relate to the two offshore substations. However, continuous working is expected between the major elements of the works, namely the foundations and turbines.

2a.11.4 It should be noted that the whole construction programme is dependent upon a number of factors, including the following:

- Consent Award;
- The selected contractors;
- Vessel Availability;
- Materials & Equipment lead times;
- Weather Windows; and
- Any seasonal restrictions for ecology.

2a.12 Operation and Maintenance

2a.12.1 This section describes the typical operation and maintenance (O&M) activities that will be required for the Offshore Project. This includes the scheduled and unscheduled maintenance activities, staff and logistical requirements.

2a.12.2 A key principle is that the wind farm will be designed to operate under minimum supervisory input. The chosen O&M concept will depend upon:

- the required O&M tasks determined by the operator and/or agreed with the main equipment suppliers to maintain operability and availability of the wind farm;
- Health, safety, security and environmental (HSSE) legislation and best practice;
- Requirements or constraints imposed by public authorities or other authorities;
- Site specific weather and metocean conditions;
- Industry best practice; and
- Optimum economic viability.

Typical O&M Activities and Staff Requirements

2a.12.3 Taking place after commissioning of the Project, O&M activities can be divided into three main categories:

- Scheduled maintenance;
- Operation and unscheduled maintenance; and
- Special maintenance in the event of major equipment breakdown and repairs.

2a.12.4 O&M activities will require year round access i.e. 365 days per year, 24 hours a day. The total number of core personnel to be employed for the Project on a permanent basis for O&M activities is estimated to be between 65 and 85.

Scheduled Maintenance

2a.12.5 Depending on the choice of turbine supplier, there will be between 1 and 2 yearly scheduled services on each turbine and the offshore substations. These scheduled services will include:

- Inspections;
- System performance assessments;
- Oil and filter change outs;
- Bolt tensioning, etc.; and
- Statutory inspections, e.g. lifting and fire equipment inspections.

2a.12.6 It is anticipated that scheduled maintenance will generally take place in the months of April to September inclusive, to avail of more favourable weather conditions.

2a.12.7 The approximate number of personnel hours and transport vessel requirements for the scheduled maintenance activities, during these months is estimated below.

2a.12.8 Each turbine will be serviced over a three day period by a four man crew during a 10 hour working shift. Each service vessel will be able to carry a maximum of 12 offshore technicians (i.e. three teams). Assuming there are 175 turbines, this gives the following estimates:

Planned maintenance, man-days:

- 3 days x 4 men x 175 WTGs = 2,100 mandays

Planned maintenance vessel days:

Assuming 3 teams of 4 men are carried on each service vessel (i.e. 3 turbines can be serviced every 3 days):

- 2,100 mandays / 3 teams (of 4) = 175 days

Planned maintenance man hours:

3 (days/ turbine) x 4 (staff/ turbine) x 10 (hours per shift) x 175 turbines = 21,000 manhours per year.

No. of vessels required for planned maintenance:

- 1 – 2 service vessels to enable completion during summer months and to allow for additional ad-hoc requirements. This will give rise to approximately 400 – 500 vessel movements a year (175 times 2 "there and back", plus ad-hoc requirements).

2a.12.9 Cable surveys and foundation inspections will initially be undertaken every two years. The interval between surveys will increase over time as cables and foundations are proven to be stable. This work will be conducted from the normal service vessel and will not add significantly to the number of vessel movements above.

Operation and Unscheduled Maintenance

2a.12.10 In addition to scheduled maintenance activities, experience shows that each turbine will need to be accessed by an O&M crew approximately once a month. These visits are for fault-finding, manual hardware resets, minor repair jobs, inspections of turbines after lightning storms, etc.

2a.12.11 Assuming a realistic 'worst case' maximum of 175 turbines, this means on average, approximately 6 turbines will be visited every day. Accessing and repairing turbines will most likely be carried out from vessels.

2a.12.12 Assuming a boat based O&M concept, there will be a maximum of twelve offshore technicians per vessel. This depends upon the nature of the visit, the locations to be covered within the wind farm and the specification of the vessel. A minimum of two service engineers will be required at any turbine for safety reasons. It is estimated that for 175 turbines, 4 to 5 service vessels will be required each day for daily operations and non-routine minor maintenance activities. This will give rise to approximately 3,000 vessel movements each year. It is expected that the completion of this work will require between 40 and 50 offshore technicians (excluding vessel crew).

2a.12.13 In addition to the offshore technicians, there will be further staff for administration, contract management, HV network operation and vessel crew required for transport.

Special unscheduled maintenance or breakdowns

2a.12.14 Although expected to be very infrequent through the life of the Project, it may be necessary to replace some of the larger components of the turbines in the event of failure or breakdown. The possible replacements can be systematic change of bearings, transformer, blades, generator or gearbox. As the size of some of these components is too large to be handled by the service vessels, jack up barges with mobile crane or larger special ships would need to be used.

2a.12.15 In addition to the maintenance of the turbines it may be that remediation work will be required on the other wind farm components, for example survey and repair work to cables and foundations.

O&M Vessel Numbers and Typical Types

2a.12.16 Overall, it is anticipated that five service vessels will be used throughout the year, with an additional vessel used during busy periods of scheduled maintenance. Figure 2a.19 and Figure 2a.20 show a typical service vessel and rigid inflatable boat (RIB) respectively that would be used to transport O&M personnel to the Offshore Project site.

Figure 2a.19: Typical service vessel which can carry 12 passengers and equipment, approx 18x7m

Figure 2a.20: Typical RIB for ferrying passengers and small tools and equipment in very calm sea conditions

O&M Logistics

2a.12.17 The methods, vessels and personnel required for the O&M operations outlined above depend to a large degree on the specific task and scope. As a general rule, service technicians will travel daily, by boat to and from the Offshore Project.

2a.12.18 Consideration will also be given to the use of helicopter; however, this would only be used in exceptional circumstances or emergency situations.

Offshore Accommodation Requirements

2a.12.19 The design and O&M strategy will determine the final operational accommodation requirements for the offshore substation and wind turbines. However, it is likely to be as follows:

Wind Turbines

2a.12.20 No permanent accommodation will be provided on the turbine structures. Emergency packs will be provided to facilitate an overnight stay if personnel are forced to stay overnight due to unexpected weather conditions. These packs are likely to contain emergency bedding, food, water etc.

Offshore Substations

2a.12.21 The offshore substations will be designed to be unmanned platforms. They will be equipped with an accommodation facility for emergency use only. The facility would take the form of a self-contained accommodation block on each offshore substation platform that would contain emergency overnight bedding, WC facilities, food, water (bottled), heat source, etc. It is anticipated that facilities for up to 8 persons would be provided on each substation.

Maintenance Port and Facilities

2a.12.22 Newhaven Port has been selected as the location for the Project O&M facility where all personnel and spares for the Project will be located. This facility will be used to direct and coordinate all activities on the offshore wind farm throughout its operational life. It will be located close to the mooring facilities for the service vessels. The choice of port has been influenced by the facilities available, the type of access and the sailing time to the site.

2a.12.23 Any requirement for new permanent facilities at Newhaven Port will be the subject of its own consent application.

2a.13 Decommissioning

2a.13.1 At the end the wind farm's design life, a decision will be made to either refurbish the scheme to extend its life by repowering it with the latest turbine technology, or to decommission the scheme. Repowering would require a further Consent application. The provisions for decommissioning are covered in this section.

2a.13.2 The requirement for decommissioning is a condition of the TCE lease and is also incorporated in the Energy Act 2004 (2004 Act), Sections 105 to 114. Sections 69 to 71 of the Energy Act 2008 introduced new provisions into the offshore renewable decommissioning regime but these do not change the overriding policy set out in the 2004 Act.

2a.13.3 Under the terms of the 2004 Act, the person or organisation responsible for the wind farm may be required to prepare and review a detailed decommissioning plan at the request of the Secretary of State and allocate funds for the purposes of decommissioning in accordance with DECC's guidance note "Decommissioning of offshore renewable energy installations under the Energy Act 2004"[17].

2a.13.4 Sections 69 to 71 of the Energy Act 2008 introduced three new provisions into the offshore renewables decommissioning regime. These provisions do not change the over-riding policy governing the decommissioning of offshore renewable energy installations as set out in the 2004 Act, but help to provide greater clarity to developers, and greater protection to taxpayers.

2a.13.5 In summary, the cost of decommissioning is to be met by the organisation responsible for the project. To ensure that these costs can be covered by the responsible organisation, the Government requires that a suitable security arrangement is entered into. There is no set method of security but the following are considered to be generally acceptable:

- Cash;
- Letters of credit;
- Bonds; or
- Early/mid life and continuous accrual decommissioning funds.

2a.13.6 It is anticipated that an agreement will be entered into that will provide for one of these methods or any other method that the Government accepts as being suitable.

2a.13.7 An indicative decommissioning schedule is presented as Figure 2a.21, it is subject to change; but provides an indication of the likely generic stages within the Decommissioning Programme. The decommissioning of the wind farm is likely to be similar to the construction activities, but in reverse. Figure 2a.21 shows the key decommissioning activities which are anticipated.

[17] Dept. of Energy & Climate Change, "Decommissioning of offshore renewable energy installations under the Energy Act 2004 – Guidance notes for industry", January 2011 (revised)

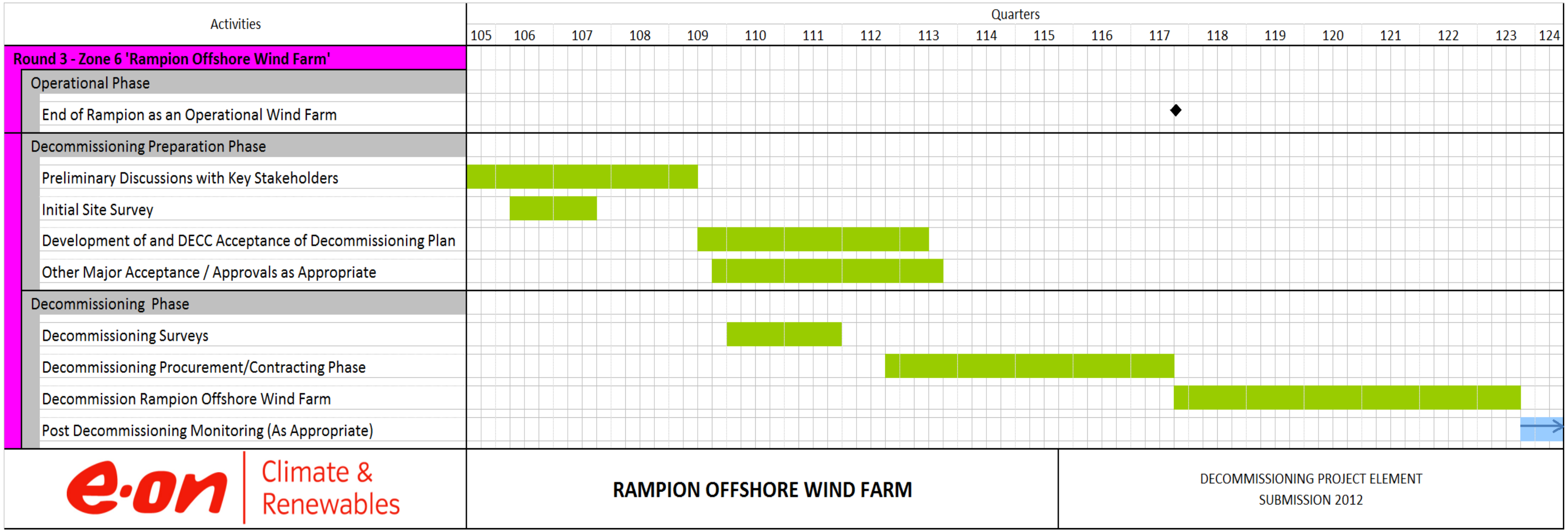


Figure 2a.21: Outline of decommissioning programme

2a.13.8 Before any plans are drawn up to decommission the wind farm, discussions will be initiated with the relevant authorities and dialogue will commence with stakeholders. It is anticipated that surveys will be required to determine the condition of the structures and investigate methods available for decommissioning.

2a.13.9 Factors that will be considered before decommissioning include:

- Amendments in legislation, i.e. statutory requirements at the time of decommissioning;
- Technological advances and availability for decommissioning work at the time the work is carried out;
- Environmental requirements and recommendations; and
- Health and safety requirements.

2a.13.10 The Waste Hierarchy (as defined in Article 4 of the EU Waste Frame Work Directive 2008), sets out the principle of how waste should be minimised:

- Prevention;
- Preparing for re-use;
- Recycling;
- Other recovery, e.g. energy recovery; and
- Disposal.

2a.13.11 Every opportunity will be used to recycle the removed equipment in the most appropriate manner. In the past for example, turbines removed from sites have being successfully re-conditioned so that they can be used again. It may also be possible to re-use some of the electrical infrastructure installed on the site. Use of the Waste Hierarchy in the design process will help to ensure that waste is minimised and components are designed for re-cycling as appropriate.

2a.13.12 For the purposes of the present consenting framework and as a basis for the EIA, the following sections set out the decommissioning process for the major components based on current technological and regulatory framework.

2a.13.13 Decommissioning can be sectioned into four stages:

Stage 1

2a.13.14 Initiate discussion with DECC (or equivalent government body) and identify structural, plant and environmental issues and commence dialogue with stakeholders.

Stage 2

2a.13.15 An initial survey of the Project site is carried out to determine the condition of structures and to form a baseline upon which the decommissioning plan will be based. A completed plan, accompanied by an ES in appropriate detail, will be submitted to TCE and DECC for approval. Proposed durations and monitoring activities will be reviewed by external consultants and their comments and any requirement of TCE/DECC will be incorporated into the plan.

Stage 3

2a.13.16 On receipt of TCE/DECC approval, the scope of work will be tendered and contactor(s) selected to undertake the decommissioning.

Stage 4

2a.13.17 Undertaking appropriate post decommissioning monitoring in accordance with the approved Decommissioning Plan.

Decommissioning methodology, risks and options

Turbines

2a.13.18 Preparation before removal from foundation/transition piece will typically include:

- Removal of all loose items from the structure;
- Disconnection of required electrical control and power cables;
- Removal of liquids such as lube oils/transformer liquids, etc.;
- Installation/certification of lifting points;
- Once the preparation scope has been completed, it is expected that the tower, blades and nacelle will be removed by crane in the reverse process of their installation; and
- Sections of the turbine, once removed, will be placed onto a transportation barge that will transport them to shore, where materials will be recycled wherever possible.

Offshore Substation

2a.13.19 Each offshore substation will be removed by single or multi-lift onto a transportation barge where it will be transported ashore for further dismantling and recycling. The following process is anticipated:

- All loose items from the substation will be removed;

- Electrical control and power cables will be disconnected;
- Removal of any liquids such as lube oils, diesel, transformer oils, etc.;
- Any gas (such as SF_6) from gas insulated switchgear will be evacuated and returned to manufacturer for recycling;
- Lifting points will be installed and certified; and
- The substation will be removed in a number of lifts onto a transport barge and transferred to shore for dismantling and recycling where appropriate.

2a.13.20 The offshore substation foundation/transition piece will be removed as described below for the turbine foundation and transition piece.

Steel Monopile Foundations

2a.13.21 Monopiles would be removed by cutting at an appropriate depth by using a high pressure water or grit jet cutter, or abrasive diamond wire cutting. Any pile remains left in the seabed are unlikely to be recovered, as removing the whole pile is regarded as neither being practical nor desirable. The following describes the likely process:

- ROVs or divers are deployed to inspect each pile footing and reinstate lifting attachments if necessary;
- The seabed within the monopile is excavated to approximately 1m below required cutting depth. Excavated soil through which the pile was originally driven, will be disposed of on the seabed adjacent to the pile.;
- A remotely operated high pressure water or grit cutting tool is set up within the monopile at the appropriate cutting depth;
- The monopile and transition piece is rigged up onto the decommissioning vessel crane;
- The monopile is internally circumferentially cut at appropriate depth;
- The section of monopile (including transition piece) is lifted out of the water and placed onto jack up vessel deck or floating barge; and
- A batch of recovered monopile and transition piece sections are transported to shore for recycling.

2a.13.22 The material around the monopile may be well consolidated and (depending on depth of cut) require significant crane capacity to remove. In worst cases, it may be necessary to use vibrating hammers as part of removal process to assist in separating the material from the pile.

2a.13.23 Another method of cutting the monopile includes wire cutting - this involves cutting through the monopile with steel cutting wire. The cut would be carried out from the outside of the pile, requiring external excavation to an appropriate cutting depth. The requirement to first remove scour protection from around the base of pile makes this option more difficult than high pressure jetting from inside the pile.

Jacket foundations (incl. IBGS and tripods)

2a.13.24 The jacket foundation decommissioning method is expected to be similar to that of the monopile explained above in that the securing pin piles will be cut at an appropriate depth whereby any piles that remain in the ground are unlikely to be recovered.

2a.13.25 It is expected that cutting will be achieved by use of high pressure water or grit jetting from the inside of the securing piles in the same manner as explained above for the monopile. Once the securing piles are cut the jacket foundation will be lifted to the surface and placed on the jack up vessel or transport barge for shipping to shore.

Gravity Base Foundations

2a.13.26 It is currently expected that the whole gravity foundation will be recovered as part of the decommissioning process. This is likely to be achieved by lifting the foundation in one lift out of the water potentially with aid of assisted buoyancy, possibly as follows:

- Ballast removal will first be undertaken to reduce the weight of the lift;
- Buoyancy aids where applicable will be attached by divers or an ROV to points on the foundation if required to assist the lift;
- The foundation is lifted out of water onto flat top barge; and
- The flat top barge with a batch of foundations is towed to shore where foundation bases are demolished appropriately and the materials recycled where possible.

2a.13.27 The design will ensure foundation ballast can be reduced prior to lifting and that the foundation can be lifted using available lifting vessels and plant. If required, attachment points will be built into the design to enable buoyancy aids to be attached to assist lifting operations.

2a.13.28 Other options that could be considered include:

- Floating the gravity structure to surface and then towing to shore;
- Leaving in situ - this option would be relevant where the size and weight of the foundation would make complete removal economically unviable or to

preserve the marine habitat that has established over the period during which the foundation had been deployed, subject to discussions with key stakeholders and regulatory bodies. If left in situ, it may be necessary to cut and remove the turbine tower from the foundation to minimise the remaining structure.

Suction Caisson Foundations

2a.13.29 It is expected that the whole suction caisson foundation will be fully recovered as part of the decommissioning process. Recovery will be through a reversal of the installation method and will include the use of a pressure hose which allows seawater inside the foundation shaft to be pumped out making the structure buoyant so that it can be recovered by a floating crane barge or jack up vessel for transport from the site.

Scour Protection

2a.13.30 It is expected that seabed scour protection materials would not be removed during decommissioning; by their nature these materials would be difficult to recover and should provide useful marine habitat which, supporting localised ecosystems which will have established over the life of the offshore wind farm.

Offshore Power Cables

2a.13.31 The intention would be to only remove those offshore cables, sections of offshore cables or cable ends which are not buried in the seabed after decommissioning of the foundations. This will be determined by survey prior to decommissioning of the site. Cables in this category will be cut below seabed level and removed by lifting the cable onto a cable retrieval vessel and the cables will be spooled back onto a drum. Recovered cable will be stripped and recycled.

2a.13.32 A water jetting or similar system would typically be required to assist the uncovering of buried cables. Any sub-sea trenches left after cable removal will be filled by natural tidal action.

Rampion Offshore Wind Farm

ES Section 2a – Offshore Project Description Figures

RSK Environmental Ltd

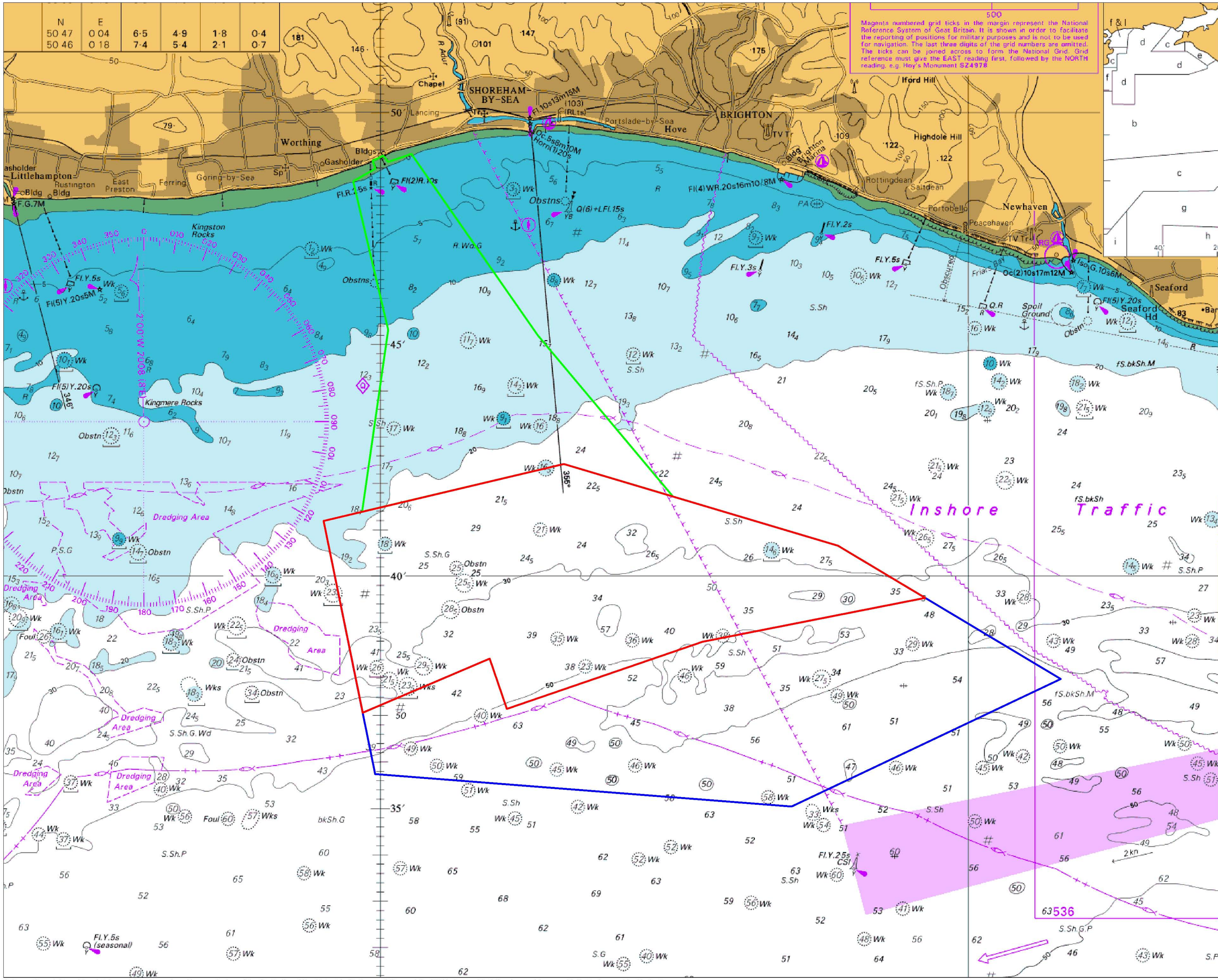
Document 6.2.2a

December 2012

APFP Regulation 5(2)(a)

Revision A

E.ON Climate & Renewables UK Rampion Offshore Wind Limited



Legend

- The Crown Estate Zone 6
- Rampion Offshore Wind Farm Site
- Export Cable Corridor

Rev	Date	Description	Drn	Chk	App
00	12.11.12	First Draft	LH	CF	DW

Rampion Offshore Wind Farm

RSK e·on

Title :

Plate 2a.1: Zone Boundary and Project Site

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Kilometres

Scale = 1:150,000 @ A3

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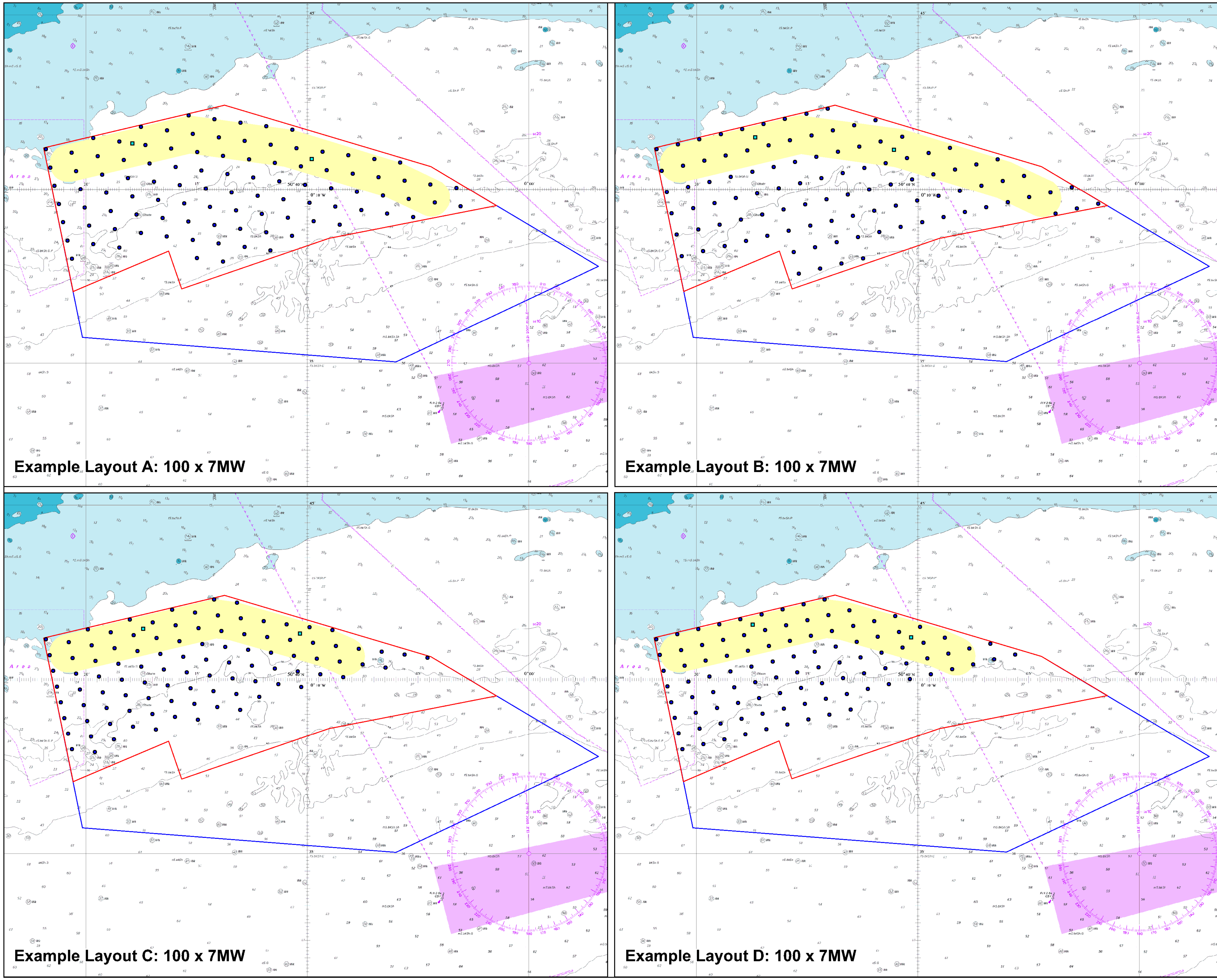
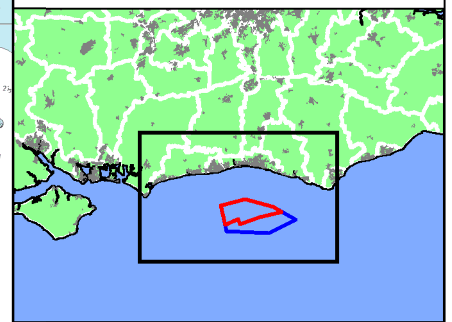


Legend :

- Proposed Turbine Location
- Indicative Sub-station Location
- The Crown Estate Zone 6
- Rampion Offshore Wind Farm Site
- Potential Substation Location Area



Rev	Date	Description	Drn	Chk	App
01	27.11.12	terminology updates	NH	DL	DW
00	19.10.12	First Draft	DL	RM	DW

Rampion Offshore Wind Farm

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Title :

Figure 2a.4: Example Turbine Layouts

0 5 10
kilometres
Scale = 1:200,000 @ A3

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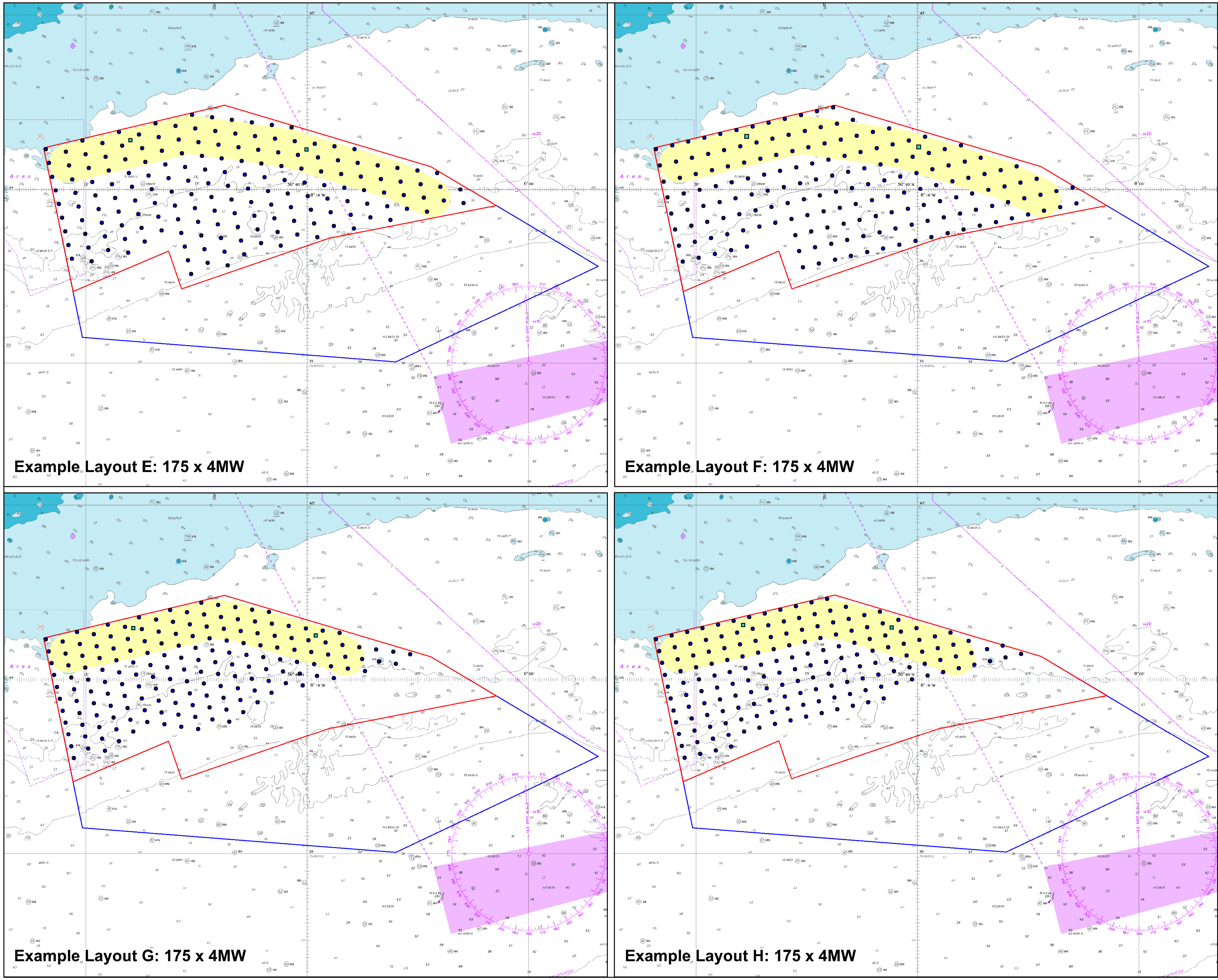
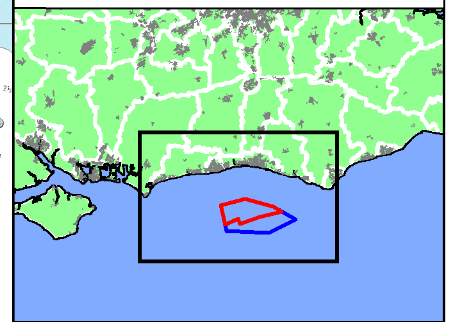


Legend :

- Proposed Turbine Location
- Indicative Sub-station Location
- The Crown Estate Zone 6
- Rampion Offshore Wind Farm Site
- Potential Substation Location Area



Rev	Date	Description	Drn	Chk	App
01	27.11.12	terminology updates	NH	DL	DW
00	19.10.12	First Draft	DL	RM	DW

Rampion Offshore Wind Farm

e·on RSK

Title :

Figure 2a.5: Example Turbine Layouts

0 5 10
kilometres
Scale = 1:200,000 @ A3

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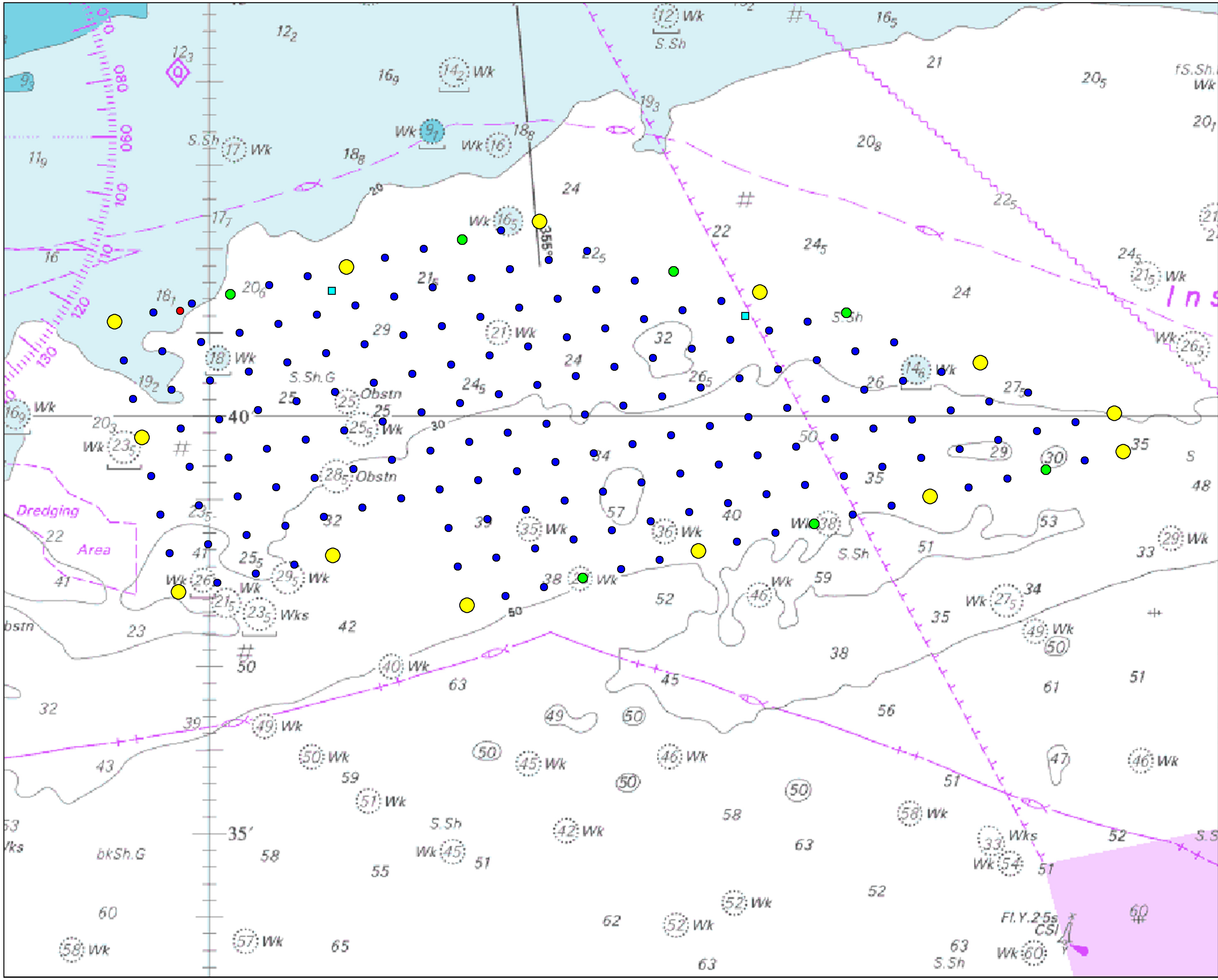

Legend :

- Proposed Turbine Location
- Indicative Sub-station Location
- SPS Lighting: flashing yellow light with range not less than 5nm
- IPS Lighting: flashing yellow light with range not less than 2nm
- Met Mast: flashing yellow light with range not less than 10nm

Rev	Date	Description	Drn	Chk	App
01	27.11.12	terminology and base map	NH	DL	DW
00	24.10.12	First Draft	AW	RM	DW

Rampion Offshore Wind Farm

Title :

Figure 2a.17: Rampion turbine plan for navigation warning lights - Indicative based on Layout F

0 0.75 1.5
nautical miles

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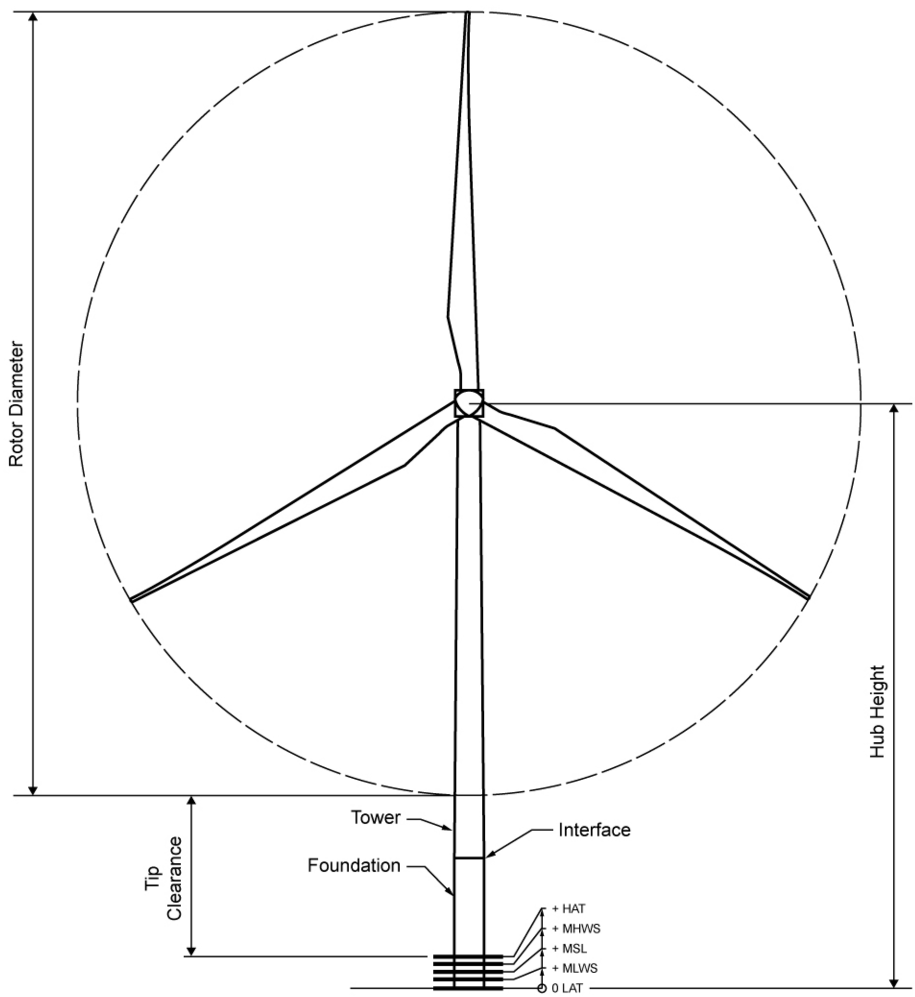

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