Dudgeon and Sheringham Shoal Offshore Wind Farm Extensions

Preliminary Environmental Information Report

Volume 1

Chapter 5 - Project Description

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Acronyms

AfL	Agreement for Lease
AIS	Air insulated switchgear
CAA	Civil Aviation Authority
CBS	Cement Bound Sand
COMAH	Control of Major Accident Hazards
CSIMP	Cable Specification, Installation and Monitoring Plan
CTV	Crew Transfer Vessel
DCO	Development Consent Order
DEP	Dudgeon Extension Project
DP	Dynamic Positioning
EIA	Environmental Impact Assessment
FTE	Full-Time Equivalent
GBS	Gravity Base Structures
GIS	Gas insulated switchgear
HAT	Highest Astronomical Tide
HDD	Horizontal Directional Drilling
HV	High Voltage
HVAC	High Voltage Alternating Current
IPMP	In-Principle Monitoring Plan
km	Kilometres
kV	Kilovolt
LAT	Lowest Astronomical Tide
MCA	Maritime and Coastguard Agency
MCZ	Marine Conservation Zone
MGN	Marine Guidance Notice
MW	Megawatts
NPPF	National Planning Policy Framework
NSIP	Nationally Significant Infrastructure Project
Ofgem	Office of Gas and Electricity Markets
OFTO	Offshore Transmission Owner
O&M	Operations and Maintenance
PEIR	Preliminary Environmental Information Report

ROV	Remotely Operated Vehicle
SAC	Special Area of Conservation
SCADA	Supervisory Control and Data Acquisition
SEP	Sheringham Shoal Extension Project
SF6	Sulphur hexafluoride
SVC	Static Var Compensator
TCE	The Crown Estate
THLS	Trinity House Lighthouse Service
TP	Transition Piece
TSHD	Trailer Suction Hopper Dredger
UPS	Uninterruptible Power Supply
UXO	Unexploded Ordnance

Glossary of Terms

The Applicant	Equinor New Energy Limited
Array cables	Cables which link the wind turbine generators to the offshore substation platforms.
Dudgeon Offshore Wind Farm Extension site	The Dudgeon Offshore Wind Farm Extension offshore wind farm boundary.
The Dudgeon Offshore Wind Farm Extension Project (DEP)	The Dudgeon Offshore Wind Farm Extension site as well as all onshore and offshore infrastructure.
Evidence Plan Process (EPP)	A voluntary consultation process with specialist stakeholders to agree the approach, and information to support, the Environmental Impact Assessment (EIA) and Habitats Regulations Assessment (HRA) for certain topics.
Grid option	Mechanism by which DEP and SEP will connect to the existing electricity network. This may either be an integrated grid option providing transmission infrastructure which serves both of the wind farms, or a separated grid option, which allows DEP and SEP to transmit electricity entirely separately.
Horizontal directional drilling (HDD) zones	The areas within the onshore cable corridor which would house HDD entry or exit points.
Jointing bays	Underground structures constructed at regular intervals along the onshore cable route to join sections of cable and facilitate installation of the cables into the buried ducts.
Infield cables	Cables which link the wind turbine generators to the offshore substation platforms.
Interlink cables	Cables linking two separate project areas. This can be cables linking: 1. DEP S and DEP N 2. DEP S and SEP 3. DEP N and SEP 1 is relevant if DEP is constructed in isolation or first with a separated grid option. 2 and 3 are relevant with an integrated grid option.
Landfall	The point on the coastline at which the offshore export cables are brought onshore and connected to the onshore export cables.
Onshore export cables	The cables which would bring electricity from the landfall to the onshore substation. 220 – 230kV
Onshore substation sites	Parcels of land within onshore substation zones A and B, identified as the most suitable location for development of the onshore substation. Two sites have been identified for further assessment within the PEIR.
Onshore Substation Zone	Parcels of land within the wider onshore substation search area identified as suitable for development of

	the onshore substation. Two substation zones (A and B) have been identified as having the greatest potential to accommodate the onshore substation.
Onshore cable corridor	The area between the landfall and the onshore substation sites, within which the onshore cable circuits will be installed along with other temporary works for construction.
Offshore export cables	The cables which would bring electricity from the offshore substation platform(s) to the landfall. 220 – 230kV
Offshore substation platform	A fixed structure located within the wind farm area, containing electrical equipment to aggregate the power generated by the wind turbines and increase the voltage before transmitting the power to shore
PEIR boundary	The area subject to survey and preliminary impact assessment to inform the PEIR, including all permanent and temporary works for DEP and SEP. The PEIR boundary will be refined down to the final DCO boundary ahead of the application for development consent.
Sheringham Shoal Offshore Wind Farm Extension site	Sheringham Shoal Offshore Wind Farm Extension lease area.
The Sheringham Shoal Offshore Wind Farm Extension Project (SEP)	The Sheringham Shoal Offshore Wind Farm Extension site as well as all onshore and offshore infrastructure.
Study area	Area where potential impacts from the project could occur, as defined for each individual EIA topic.
Transition joint bay	Connects offshore and onshore export cables at the landfall. The transition joint bay will be located above mean high water

5 PROJECT DESCRIPTION

5.1 Introduction

1. This chapter of the Preliminary Environmental Information Report (PEIR) provides a description of the key components of the proposed Dudgeon Offshore Wind Farm Extension Project (hereafter DEP) and Sheringham Shoal Offshore Wind Farm Extension Project (hereafter SEP), as well as details of how the wind farms will be constructed, operated, maintained and decommissioned. The details provided inform and underpin the assessments that have been undertaken, although **Chapters 8 – 32** should be referred to for details of the worst case scenarios that apply to each topic.
2. DEP and SEP will have a maximum export capacity of up to 448 megawatts (MW) and 338MW respectively (up to 786MW in total).The closest point to the coast is 13.6 kilometres (km) from SEP and 24.8km from DEP (**Figure 5.1** and **Figure 5.2**).
3. DEP and SEP will be connected to shore by offshore export cables installed to the landfall at Weybourne, on the north Norfolk coast. From there, the onshore export cables travel approximately 60km inland to a high voltage alternating current (HVAC) onshore substation near to the existing Norwich Main substation. The onshore substation will be constructed to accommodate the connection of both DEP and SEP to the transmission grid.
4. The key offshore components comprise:
    - Wind turbines;
    - Offshore substation platform/s (OSP);
    - Foundation structures for wind turbines and OSP/s;
    - Infield cables;
    - Interlink cables; and
    - Export cables from the wind farm site/s to the landfall.
5. The key onshore components comprise:
    - Landfall and associated transition joint bay;
    - Onshore export cables installed underground from the landfall to the onshore substation and associated joint bays and link boxes;
    - Onshore substation and onward 400 kilovolt (kV) connection to the existing Norwich Main substation;
    - Trenchless crossing zones (e.g. Horizontal Directional Drilling (HDD));
    - Construction and operational accesses; and
    - Construction compounds.

5.1.1 Project Development Scenarios

6. As set out in **Chapter 1 Introduction**, whilst DEP and SEP have different ownership and are each Nationally Significant Infrastructure Projects (NSIPs) in their own right, a single application for development consent will be made to address both wind farms, and the associated transmission infrastructure. A single planning process and Development Consent Order (DCO) application is intended to provide for consistency in the approach to the assessment, consultation and examination, as well as increased transparency for a potential compulsory acquisition process.

7. Furthermore, the Applicant will seek to develop DEP and SEP as an integrated project, with an integrated grid option providing transmission infrastructure which serves both of the wind farms being the preferred option. This strategic approach will particularly benefit the planning and construction of the electrical infrastructure system, is likely to reduce the overall environmental impact and disruption, and responds to concerns regarding the lack of an holistic approach to offshore wind development in general.

8. However, given the different ownership arrangements of each Project, a separated grid option (i.e. transmission infrastructure which allows each Project to transmit electricity entirely separately) will allow DEP and SEP to be constructed in a phased approach, if necessary. Therefore the DCO application will seek consent for alternative grid solutions in the same overall corridors to allow for both the integrated and separated grid options.

9. Whilst DEP and SEP will be the subject of a single DCO application (with a combined Environmental Impact Assessment (EIA) process and associated submissions), each Project is assessed individually, accounting for both the separated and integrated grid options, so that mitigation is specific to each development scenario. As such, the assessments cover the possibility that (**Table 5-1**):

- Both DEP and SEP are developed, either concurrently or sequentially ('together' scenarios, whereby either a separated or an integrated grid option could apply).
- One or the other (but not both) projects are developed ('in isolation' scenarios, whereby only a separated grid option would apply).

Table 5-1: Development scenarios

Potential development scenarios	Grid option
DEP and SEP together – concurrent build	Integrated
DEP and SEP together – sequential build	
DEP and SEP together – sequential build	Separated
DEP and SEP together – concurrent build	
DEP in isolation	
SEP in isolation	

10. The development scenarios, including the associated configurations of export and/or interlink cables, are illustrated in **Figures 5.5** to **5.7**.

11. The EIA considers the appropriate realistic worst-case associated with the different development scenarios and presents the results accordingly. The information provided in this chapter is designed to clearly show how the project design envelope would differ depending on which scenario may be taken forward.

12. In summary, the following principles set out the framework for how DEP and SEP may be developed:
    - DEP and SEP may be constructed at the same time, or at different times;
    - If built at the same time both DEP and SEP could be constructed in four years;
    - If built at different times, either Project could be built first;
    - If built at different times the first Project would require a four-year period of construction and the second Project a three-year period of construction;
    - If built at different times, the duration of the gap between the start of construction of the first Project, and the start of construction of the second Project may vary from two to four years;
    - Taking the above into account, the maximum construction period over which the construction of both Projects could take place is seven years.

13. The impact assessments therefore consider the following development and build out scenarios:
    - Build DEP or build SEP in isolation;
    - Build DEP and SEP concurrently – reflecting the maximum peak effects; and
    - Build DEP and SEP sequentially with a gap of up to four years between the start of construction of each Project – reflecting the maximum duration of effects.

5.1.2 Flexibility and the Project Design Envelope

14. The project design envelope described in this chapter provides for a reasoned minimum and maximum extent for each parameter. The detailed design of DEP and SEP will be developed and refined within this consented envelope prior to construction, with the final design lying between the minimum and the maximum extent of the consent. This approach to the EIA, also known as the 'Rochdale Envelope' approach is further described in **Chapter 6 EIA Methodology**.

15. As such, the information presented in this chapter outlines the options and flexibility required along with the range of potential design and activity parameters upon which the subsequent impact assessment chapters are based. The envelope will continue to evolve throughout the EIA process, prior to being fixed at a point between the consultation on the draft assessments presented in this PEIR and completion of the Environmental Statement (ES) that will be submitted alongside the DCO application.

16. The need for flexibility in the consent is a key aspect of any large development but is particularly significant for offshore wind projects where technology continues to evolve quickly. The project design envelope must therefore provide sufficient flexibility to enable the Applicant and its contractors to use the most up to date, efficient and cost-effective technology and techniques in the construction, operation, maintenance and decommissioning of DEP and SEP.

17. Key aspects of DEP and SEP for which flexibility in the project design envelope is required include:
    - Wind turbine capacity, including parameters such as maximum tip height and foundation type, to benefit from improvements in technology prior to offshore construction;
    - Construction and maintenance methodologies, as above, to enable competitive procurement and the most cost effective option to be adopted post-consent; and
    - The development scenarios detailed above (**Section 5.1.1**), namely that either DEP or SEP are developed in isolation, or DEP and SEP are both developed, either concurrently or sequentially.
18. This chapter outlines the full range of parameters for the aspects of DEP and SEP where flexibility is required.

5.1.3 The PEIR Boundary

19. For the purpose of the PEIR, the 'PEIR boundary' has been identified which encompasses the area subject to survey and preliminary impact assessment, including all permanent and temporary works for DEP and SEP. The PEIR boundary will be refined down to the final DCO boundary (the 'red line boundary') ahead of the application for development consent.
20. The PEIR boundary with respect to the offshore works for DEP and SEP is described in **Section 5.1.4.1** below. However, the offshore PEIR boundary also includes the area of the existing Dudgeon offshore wind farm (OWF), as shown on **Figure 5.3**. The inclusion of the Dudgeon OWF in the offshore PEIR boundary reflects the intention of the Applicant to include the same in the DCO alongside a mechanism to release 'headroom' for the benefit of DEP and/or SEP. This possibility arises as a result of the Dudgeon OWF not having been built out to its full consented capacity, meaning that there is a difference between certain of the consented parameters (such as total rotor swept area) and the as built parameters.
21. The inclusion of the Dudgeon OWF in the DCO boundary together with the appropriate DCO mechanism is intended to give the necessary legal certainty to allow that headroom to be accounted for in the environmental assessment process i.e. to allow the assessments to be based on the as built parameters rather than consented. The advantage of this approach is that it enables the assessments to be undertaken on a more realistic basis. It should be noted that the DCO will not provide for any additional works to be undertaken within the existing Dudgeon OWF boundary; its inclusion is solely to enable the release of headroom. For this reason, the assessments set out in this PEIR are focussed on the DEP and SEP boundaries only. Where the matter of headroom is of relevance to the assessments, specifically ornithology, both consented and as built parameters have been considered such that the worst case has been addressed. Further details with regard to the assessment approach for ornithology are provided in **Chapter 13 Offshore Ornithology**.
22. The PEIR boundary with respect to the landfall and the onshore works is detailed in **Sections 5.5** and **0**.

5.1.4 Site Description

5.1.4.1 Offshore

23. DEP and SEP are located in the Greater Wash region of the southern North Sea, with the closest point to the coast being 13.6km from SEP and 24.8km from DEP (**Figure 5.1** and **Figure 5.2**). The offshore PEIR boundary (**Section 5.1.3**) includes the DEP and SEP wind farm sites as defined by The Crown Estate Agreement for Lease (AfL) areas. The DEP wind farm site is divided into two distinct areas: DEP North and DEP South. The offshore PEIR boundary also includes the offshore cable corridors that either connect the wind farm sites together (interlink cables) or connect the wind farms to the landfall (export cables).

24. Water depths at the DEP and SEP wind farm sites range from 14m below Lowest Astronomical Tide (LAT) in the northwest of SEP to 36m in the northwest of DEP North. The seabed gradient across both wind farm sites is generally relatively flat (i.e. less than 1°), although steeper gradients are associated with areas of sand waves, particularly in the northwest of DEP North and DEP South.

25. Water depths along the interlink cable corridors are between 10m and 35m. Again, the seabed is relatively flat, other than in areas of sand waves which are found predominantly at the northern end of the SEP to DEP North corridor and between DEP South and DEP North, on the south west side of the Dudgeon OWF.

26. Water depths within the export cable corridor range from 25-27m in the offshore part closest to SEP, shallowing to about 16m near the eastern tip of Sheringham Shoal sand bank and then decreasing progressively to 0m at the coast. The 5m contour is typically 200-300m from the coast.

27. The geology of DEP and SEP generally consists of Holocene deposits overlying a series of Pleistocene sands and clays, with a bedrock of Upper Cretaceous Chalk. The chalk is only exposed at the seabed within the landward 500m of the export cable corridor, beyond which and out to the Sheringham Shoal sand bank, it is sub-cropping beneath alternating zones of thin gravelly sand/gravel and Holocene sand. As such, the predominant surface sediment types across the offshore project area are medium and coarse sands and gravels, and outcropping chalk in the landward 500m of the export cable corridor.

28. The export cable corridor passes through the Cromer Shoal Chalk Beds Marine Conservation Zone (MCZ) as it approaches the coast.

5.1.4.2 Onshore

29. The onshore site selection process has sought to avoid settlements, sensitive habitats and taken into account other technical and environmental constraints (see **Chapter 4 Site Selection and Assessment of Alternatives**). As a result, the landfall, onshore cable corridor and onshore substation sites are located in predominantly agricultural areas. There are a number of towns and villages in proximity to the proposed Project infrastructure including Weybourne, Oulton, Cawston, Barford and Swardeston (**Figure 5.4, Figure 5.9** and **Figure 5.10**).

5.2 Consultation

30. The Applicant is undertaking an extensive programme of community and stakeholder consultation to inform the EIA process and the design of DEP and SEP. Further details are provided in:

- **Chapter 6 EIA Methodology** – an overview of the consultation undertaken in the context of the wider EIA process.
- **Chapter 7 Technical Consultation** – summarises the consultation undertaken to inform and focus the approach to each technical aspect of the EIA. Specific details of how the Project has taken account of the comments received are provided in each chapter of the PEIR where relevant.

31. Full details of the consultation process including wider community consultation will also be presented in the Consultation Report, which will be submitted as part of the DCO application.

32. Key project design decisions that have been made by the Applicant as a result of the consultation process and feedback received to date include:

- The intention to develop DEP and SEP as an integrated project with an integrated grid option providing transmission infrastructure which serves both of the wind farms, as detailed in **Section 5.1.1**. This benefits the planning and construction of the electrical infrastructure system, is likely to reduce overall levels of environmental impact and disruption, and helps to respond to any concerns regarding the lack of a holistic approach to offshore wind development.
- Selection of the landfall at Weybourne with an export cable corridor through the western portion of the MCZ. This avoids the Wash and North Norfolk Coast Special Area of Conservation (SAC) and reduces the overall length of the export cable corridor.
- Commitment to no more than 100m of external cable protection per export cable in the MCZ, in relation to unburied cables. This reduces the extent of any longer term impacts on the MCZ.
- Commitment to not using loose rock type external cable protection systems in the MCZ. This facilitates the possibility of removal on decommissioning.
- Should a plough be selected as the appropriate burial tool for the DEP and SEP export and/or interlink cables, a non-displacement type will be used to minimise environmental impact.
- Use of long HDD at the landfall in order to avoid works such as trenching on the beach and cliffs and the complete avoidance of the sensitive outcropping chalk feature in the nearshore portion of the MCZ.
- The location of the new onshore substation in proximity to the existing Norwich Main substation to minimise the proliferation of industrial infrastructure within the landscape.

33. **Table 5-2**: summarises the key Scoping Opinion responses that relate specifically to the development of the project description at the PEI stage. Further details are provided in the relevant technical chapters.

Table 5-2: Summary of key Scoping Opinion responses related to the development of the project description at the PEI stage.

Scoping Opinion section reference	Comment made	Response and where addressed in the PEIR
General points		
2.3.1	The ES should include the following: - a description of the Proposed Development comprising at least the information on the site, design, size and other relevant features of the development; and - a description of the location of the development and description of the physical characteristics of the whole development, including any requisite demolition works and the land-use requirements during construction and operation phases.	These points are addressed throughout the Project Description chapter.
2.3.2	The maximum technical capacity (ie electrical output) of the individual wind turbines and of the Proposed Development as a whole should be confirmed within the ES.	The capacity of the Proposed Development is addressed in **Section 5.3** and of individual turbines in **Section 5.4.2**.
2.3.3	The Inspectorate notes that timely refinement of options will support a more robust assessment of likely significant effects and increase certainty for those likely to be affected.	The Applicant has noted the need to refine the options in a timely manner, as reflected in this chapter. A summary of the project design envelope and flexibility required is provided in **Section 5.1**.
2.3.4	Construction programme	Further information on the construction programme is provided in **Section 5.7** of this chapter.

Scoping Opinion section reference	Comment made	Response and where addressed in the PEIR
2.3.5	The ES should specify the anticipated working hours for construction. Any need for unsocial hours of working should be detailed.	These are provided in **Section 5.7** of this chapter.
2.3.6	The ES should provide a full description of the nature and scope of [operation and maintenance] activities, including the types of activity, their frequency, and how works will be carried out for both the onshore and offshore elements of the Proposed Development.	Operation and maintenance activities are described in **Section 5.4.10** (offshore) and **5.6.1.7** and **5.6.2.6** (onshore).
2.3.7	The anticipated operational lifespan of the Proposed Development… should be clearly and consistently defined within the ES to provide a clear indication of the likely duration of operational impacts.	The operational lifespan / design life of DEP and SEP is 35 years, as stated in **Sections 5.4.10-5.4.11** of this chapter. This is reflected in the topic assessment chapters where relevant.
2.3.8	The ES should include the rationale in support of the assessment of potential significant effects during the decommissioning phase, including a description of anticipated decommissioning activities. Where there is uncertainty around the impacts of decommissioning this should be clearly explained along with the implications for the assessment of significant effects.	Decommissioning activities are described in **Section 5.4.12** (offshore) and **5.6.1.8** and **5.6.2.7** (onshore). Potential impacts relating to the decommissioning works are considered throughout the topic assessment chapters.
Offshore		
2.3.9	The ES should clearly describe the different permutations of the Proposed Development that would arise should both, or just one of DEP/SEP, be	The project development scenarios are described in **Section 5.1.1** of this chapter, including an explanation of how consideration of these

Scoping Opinion section reference	Comment made	Response and where addressed in the PEIR
	constructed. This should include a clear description of the electrical infrastructure that would be installed in each circumstance. Figures to depict the arrangements for these alternative options would aid in this understanding.	has been incorporated into the assessments. **Figures 5.5 to 5.7** show the differences between the development scenarios in terms of the interlink and export cable configurations. Differences between the scenarios are clearly described throughout this chapter. Each topic assessment chapter also describes the differences relevant to the topic/assessment in question. Assessments have been undertaken for the Projects 'in isolation' as well as 'together' including, for the latter, consideration of whether a concurrent or sequential development scenario is the worst case.
2.3.10	Section 1.5.6.2 of the Scoping Report identifies the need for seabed preparation for foundations. Any requisite seabed preparation for the array cables, the interlink cables and the export cable route should also be described and any resultant likely significant effects assessed within the ES. Should seabed preparation involve dredging, the ES should identify the quantities of dredged material and identify the likely location for disposal.	Seabed preparation requirements in relation to the wind turbine foundations are described in **Section 5.4.3**, in relation to the subsea cables in **Section 5.4.7.4.1** and the HDD exit pit works in **Section 5.5**. This includes consideration of disposal where relevant and all of these matters are reflected in the topic assessment chapters as appropriate.
2.3.11	The ES should identify the worst-case footprint of seabed disturbance that would arise from all offshore construction activities, for example seabed clearance/preparation, and	Both temporary and permanent seabed footprints are discussed throughout this chapter and a summary for the offshore works is provided for ease of reference in

Scoping Opinion section reference	Comment made	Response and where addressed in the PEIR
	vessel jack up and anchoring. The maximum footprints of all permanent components should also be identified.	**Section 5.4.1**. Footprints are also presented in the worst case scenario tables included in each topic assessment chapter, as relevant.
2.3.12	The ES should quantify the anticipated worst-case amount of scour and cable protection (including for cable crossings) that would be utilised for the Proposed Development, including for the export cables.	Scour protection in relation to foundations is addressed in **Sections 5.4.3** and **5.4.4**. Cable protection including at cable crossings, as well as at the HDD exit pit is described in **Section 5.4.7.7** and **Section 5.5**.
2.3.13	The Scoping Report identifies a number of wind turbine foundation options which could be used for the Proposed Development...The Applicant should ensure that the ES clearly identifies and assesses the worst-case scenario for the different environmental aspects and matters that could be significantly affected.	The wind turbine foundation options are described in **Section 5.4.3** of this chapter. The worst case scenario differs according to the receptor and impact in question (for example the greatest seabed footprint of a gravity base system foundation vs the underwater noise generated by piling of monopile foundations) – this is clearly identified in each topic assessment chapter.
2.3.14	The Inspectorate expects the ES to confirm the maximum length of both array and interlink cables so that the likely significant effects of these elements can be understood.	The maximum length of export, array (termed infield) and interlink cables is clearly described in **Section 5.4.7**, for each development scenario.
2.3.15	Paragraph 141 of the Scoping Report states that the maximum hammer size for pile driving would be 4500kJ. The ES should also describe the maximum diameter of piles should they be used.	Maximum hammer energy and pile diameters are described in **Sections 5.4.3** and **5.4.4**. The maximum hammer energy for monopiles is now 5,500kJ. Further detail in relation to the impacts of underwater noise and the underwater noise modelling

Scoping Opinion section reference	Comment made	Response and where addressed in the PEIR
		study is provided in **Chapter 11 Fish and Shellfish Ecology** and **Chapter 12 Marine Mammals**.
Onshore		
2.3.16	The Scoping Report states that the cable corridor is 500m wide, however the scale on the figures indicates a greater width than this. The Inspectorate acknowledges that the final cable corridor will be refined for the application. The Applicant should ensure that the project description within the ES and any figures reflect one another appropriately.	See **Section 5.6.1**
2.3.17	The Scoping Report identifies the need for jointing bays and link boxes up to every 300m. The ES should identify a worst case scenario for the number of jointing pits and link boxes.	The worst case total number of link boxes and joint bays is detailed in **Section 5.6.1.2**.
2.3.18	The Scoping Report states that the Proposed Development may incorporate balancing equipment/storage infrastructure, such as a battery which would be housed within the footprint of the onshore substation. The ES should include sufficient detail to describe such equipment in order to provide confidence that any potential effects have been assessed in the ES	Balancing/storage infrastructure is no longer included with the proposals and therefore does not form part of the application for development consent or this PEIR.
2.3.19	The Scoping Report has identified the need for access roads to the onshore substation. The ES should identify whether new routes, either temporary or permanent, are required to	The onshore substation will require a permanent operational access. The location of this will be confirmed once a preferred substation option has been

Scoping Opinion section reference	Comment made	Response and where addressed in the PEIR
	access the onshore cable corridor and/or the temporary compounds. The likely significant effects of all temporary and permanent accesses should be included in the assessment scope.	identified and will be reported in the ES. The potential accesses required for construction have been identified and are considered further within **Chapter 26 Traffic and Transport**.
2.3.20	Given the length of the onshore cable, there is the potential for numerous points at which the cable will need to cross roads, railways, watercourses, gas, water and electrical infrastructure. The ES should identify the locations and type of all such crossings. Where commitments are made within the ES to use a specific method as mitigation (e.g. trenchless techniques at sensitive locations), the Applicant should ensure that such commitments are adequately secured.	A crossing schedule is included as **Appendix 5.1** of this Chapter.
2.3.21	The Scoping Report states that the onshore substation may connect to the existing Norwich Main substation through either an overhead connection or an underground connection, depending on their proximity to one another. The Inspectorate expects the ES to provide greater clarity as to the necessary connection works in order to inform a meaningful assessment of likely significant effects.	The connection between the onshore substation and the existing Norwich Main will be an underground 400kV cable.

5.3 Overview of the Project

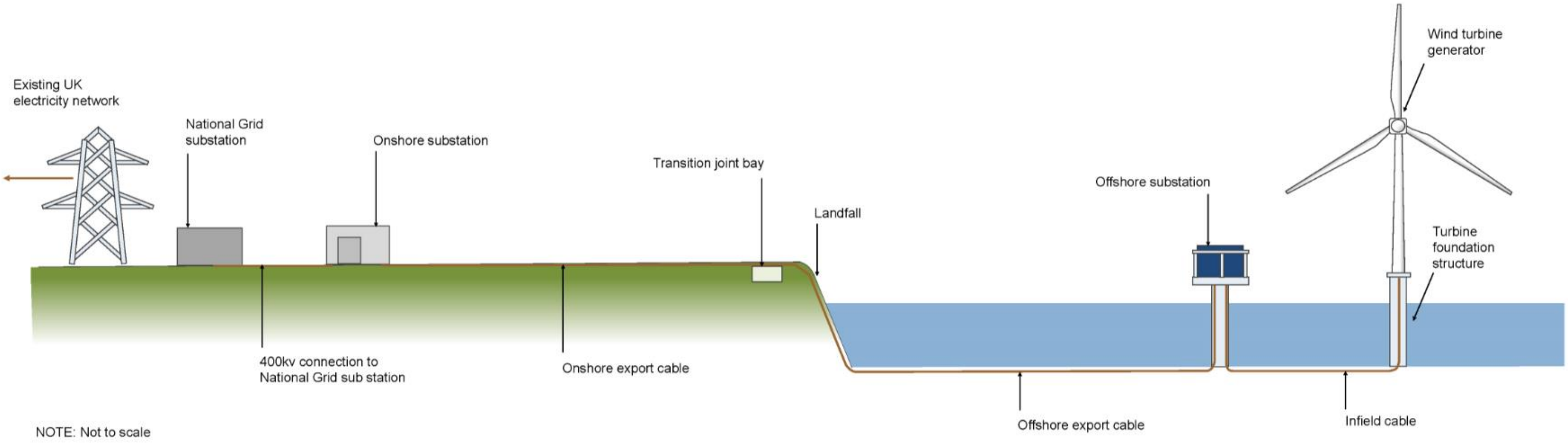
34. DEP will consist of between 17 and 32 wind turbines, each having a rated capacity of between 14MW and 26MW and therefore with a total export capacity of up to 448MW. SEP will consist of between 13 and 24 wind turbines, each having a rated capacity of between 14MW and 26MW and therefore with a total export capacity of up to 338MW. Taken together, there will be between 30 and 56 wind turbines, producing a total export capacity of up to 786MW. The locations of the DEP and SEP sites and offshore cable corridors are shown on **Figure 5.2**.

35. The Applicant has an agreement with National Grid of supplying up to 719MW at Norwich Main substation, however transferring electricity over the distances involved results in losses in the cable infrastructure. To compensate for these losses, the Applicant proposes to develop DEP and SEP with a capacity that exceeds the installed capacity of the operational Dudgeon and Sheringham Shoal OWFs. The plan level HRA undertaken for the UK Offshore Wind Extension Round (The Crown Estate (TCE), 2019) took account of installed capacities of 402MW at DEP and 317MW at SEP (719MW combined), to match the existing capacities of the Dudgeon and Sheringham Shoal OWFs. However, any additional capacity at DEP and SEP to account for cable losses will be achieved by boosting the capacity of the individual turbines rather than adding additional turbines to the layout.

36. Depending on the development scenario (**Section 5.1.1**), the wind farm sites will be connected to one another via interlink cables, with either a single OSP at SEP, or one OSP at SEP and a second at DEP North (**Figures 5.5** to **5.7**). An offshore export cable corridor will link the wind farm site/s with the cable landfall at Weybourne. An onshore cable corridor will link the landfall with the grid connection point at Norwich Main. An HVAC transmission system will be used for the transmission of the power from the wind farm site/s to the onshore substation.

37. An overview schematic of the key onshore and offshore project infrastructure is provided in **Plate 5-1**.

Plate 5-1: Project overview schematic (N.B. not to scale).



38. The earliest that construction could commence under any scenario is anticipated to be 2024, with the onshore construction works likely to commence first. **Section 5.7** provides an indicative construction programme for each development scenario, for both the offshore and onshore works.

5.3.1 Key Project Components

39. The following section provides an overview of the key offshore and onshore project components which are described in further detail in **Sections 5.4** to **0**.

40. The key offshore components are:
    - Offshore wind turbines and their associated foundations;
    - OSP/s and their associated foundations;
    - Scour protection around foundations; and
    - Subsea cables comprising:
        - Offshore export cables (linking the OSP/s to the landfall)
        - Interlink cables (linking two separate project areas)
        - Infield cables (linking the wind turbine generators to the OSP/s)
        - External cable protection on subsea cables as required
        - Fibre optic communications cables, integrated with the power cables.

41. The key components at the landfall are:
    - Up to two ducts (one per project) installed under the cliff by HDD. An additional drill per project is included (four in total) in the impact assessment worst case scenarios where applicable, for contingency purposes in the unlikely event of HDD failure; and
    - Up to two transition joint bays to house the connection between the offshore and onshore cables.

42. The key onshore components are:
    - Ducts installed underground to house the electrical cables along the onshore cable corridor;
    - Onshore cables installed within ducts;
    - Joint bays and links boxes installed along the cable corridor;
    - Trenchless crossing points at certain locations such as some roads, railways and sensitive habitats (e.g. rivers of conservation importance);
    - Temporary construction compounds and accesses;
    - An onshore substation and onward 400kV connection to the existing Norwich Main substation ; and
    - Permanent operational substation access.

5.4 Offshore

5.4.1 Offshore Scheme Summary

43. A summary of the key elements of the offshore infrastructure is provided in **Table 5-3**:.

Table 5-3: Offshore scheme summary

Parameter	Details		
	DEP	SEP	Combined
Export capacity (MW)	448	338	786
Lease period (years)	50	50	50
Indicative construction duration (years) (excluding landfall works)	2	2	4 (max. gap of 4 years between DEP and SEP, start to start)
Anticipated design life (years)	35	35	35
Number of wind turbines	17-32	13-24	30-56
Wind farm area (array) (km^2)	103.50	92.60	196.10
Closest point from wind farm site to coast (km)	24.80	13.60	n/a
Length of export cable SEP to landfall (per cable) (km)	n/a	40	n/a
Length of export cable DEP to landfall[1] (per cable) (km)	62	n/a	62
Maximum number of export cables and trenches	1 & 1	1 & 1	2 & 2
Maximum total length of all interlink cables[2] (km)	154		
Maximum turbine rotor diameter (m)	300	300	n/a
Maximum tip height above Highest Astronomical Tide (HAT) (m)	330	330	n/a

[1] Applies either to a DEP in isolation development scenario, or for DEP and SEP together with a separate OSP at DEP i.e. separated grid option

[2] Applies to the integrated grid option with 1 OSP at SEP and assuming only DEP North is developed – see **Section 5.4.7.2** for further details

Parameter	Details		
	DEP	SEP	Combined
Minimum clearance (air gap) above HAT (m)	26	26	n/a
Rotor swept area (km^2)	1.19-1.41	0.90-1.06	2.08-2.48
Indicative minimum and maximum separation between wind turbines (inter-row) (km)	0.99-3.3	0.99-3.3	n/a
Maximum infield cable length (not incl. interlink cables) (km)	135	90	225
Wind turbine foundation type options	Piled monopile; Suction bucket monopile; Piled jacket; Suction bucket jacket; and Gravity base structure (GBS).		
Met masts	0	0	0
Maximum number of OSPs	1	1	2
OSP foundation type options	Piled jacket; or Suction bucket jacket.		

5.4.1.1 Maximum Spatial Footprints of Offshore Infrastructure

44. The spatial footprints caused by the construction or decommissioning works (generally assessed as temporary footprints) as well as those caused during the lifetime of the wind farms during operation are summarised in the following sections. All figures are presented on a worst case basis e.g. for wind turbine foundations, the maximum footprint described is that which would result from the installation of the highest possible number of gravity base structures (all with scour protection), which is the scenario with the largest footprint on the seabed.

5.4.1.1.1 Temporary construction footprint

45. **Table 5-4**: describes the maximum temporary construction footprints in the wind farm sites and cable corridors. This includes seabed preparation for foundation installation and cable installation.

Table 5-4: Maximum temporary construction footprints

Activity	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
Seabed preparation	32 (DEP) and 24 (SEP) 14MW wind	55,520	41,640	97,160

Activity	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
– wind turbines	turbines on GBS foundations			
Jack up vessel footprint – wind turbine and OSP installation	32 (DEP) and 24 (SEP) 14MW wind turbines and 2 OSPs	79,200	60,000	139,200
Anchoring footprint – wind turbine and OSP installation	32 (DEP) and 24 (SEP) 14MW wind turbines and 2 OSPs	23,760	18,000	41,760
Seabed preparation – OSP/s	Not required	0	0	0
Pre-grapnel run (all cables)	Up to 3m disturbance width but encompassed by footprint of cable installation works.	n/a	n/a	n/a
Cable route pre-sweeping works	Four areas as described in **Section 5.4.7.4.1.3**.	929,719	n/a	929,719
Anchoring footprint – export cable installation	Seven mooring lines and an anchor footprint of up to 30m^2, and repositioning of the mooring lines every 500m. Export cable lengths 62km (DEP), 40km (SEP) and 102km (DEP and SEP with 1 OSP at SEP and 1 OSP at DEP North)	26,040	16,800	42,840
Anchoring footprint –	The development scenario with the	27,720	0	64,680

Activity	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
interlink cable installation	greatest overall length of interlink cabling is the integrated grid option for DEP & SEP together, with 1 OSP at SEP (assuming only DEP North is developed). Total length of 154km. Refer to **Section 5.4.7.2** for further details.			
Boulder clearance – wind farm areas	Clearance of an estimated 20 boulders in SEP and 10 across both DEP North and DEP South, each of up to 5m in diameter and accounting for both lifting and placement.	393	785	1,178
Boulder clearance – export cable corridor	Clearance of an estimated 20 boulders in the export cable corridor/s in total, each of up to 5m in diameter and accounting for both lifting and placement.	393	393	785
Export cable installation	1 export cable per project: 62km (DEP), 40km (SEP) and 102km (DEP and SEP with 1 OSP at SEP and 1 OSP at DEP North), 3m disturbance width.	186,000	120,000	306,000
Interlink cable installation	The development scenario with the greatest overall	198,000	0	462,000

Activity	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
	length of interlink cabling is the integrated grid option for DEP & SEP together, with 1 OSP at SEP (assuming only DEP North is developed). Total length of 154km, 3m disturbance width. Refer to **Section 5.4.7.2** for further details.			
Infield cable installation	Up to 135km of infield cables at DEP and 90km at SEP, 3m disturbance width	405,000	270,000	675,000

5.4.1.1.2 Wind farm sites lifetime footprint

46. **Table 5-5**: describes the maximum lifetime footprints in the wind farm sites. This includes the foundations, crossings and external cable protection for unburied cables.

Table 5-5: Maximum lifetime footprints in the wind farm sites (wind turbines, OSPs and infield cables)

Infrastructure	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
Wind turbine foundations	32 14 MW wind turbines at DEP and 24 at SEP, all with GBS foundations and all with scour protection	458,048	343,536	801,584
OSP foundations	1 OSP at each of DEP and SEP, both on a jacket foundation with suction buckets and scour protection	1,662	1,662	3,324
Infield external	Total allowance of 1,000m across both	4,000	4,000	4,000

Infrastructure	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
cable protection (unburied cables)	projects, up to 4m wide. Either project may use the total allowance.			
Infield external cable protection (cable crossings)	7 crossings (Durango to Waveney pipeline (3); Lancelot to Bacton pipeline (2); and Shearwater to Bacton pipeline (2)). All up to 21m wide and 100m long.	14,700	0	14,700
Total	**-**	**478,410**	**349,198**	**823,608**

5.4.1.1.3 Cable corridors lifetime footprint

47. **Table 5-6**: describes the maximum lifetime footprints in the interlink and export cable corridors. This only concerns crossings and any external cable protection that may be used, including at the HDD exit.

Table 5-6: Maximum lifetime footprints, interlink and export cables

Infrastructure	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
External cable protection – unburied cables	Total allowance of 500m for the export cables (6m wide) and 1,500m for the interlink cables (6m wide). Either project may use the total allowance.	12,000	12,000	12,000
External cable protection – cable crossings	8 export cable crossings (up to 2 DEP & SEP cables crossing 2 export cables for each of Dudgeon and Hornsea Project Three OWFs) 6 interlink cable crossings (up to 3 interlink cables from DEP South crossing 2 Dudgeon OWF export cables).	21,000	8,400	29,400

Infrastructure	Worst case scenario description	Footprint – DEP (m^2)	Footprint – SEP (m^2)	Footprint – combined (m^2)
	All up to 21m wide and 100m long.			
External cable protection – HDD exit	Based on 100m protection of each of the export cables, 3m wide	300	300	600
Total	**-**	**33,300**	**20,700**	**42,000**

5.4.1.1.4 Operation and maintenance temporary footprint (all areas)

48. **Table 5-7**: describes the maximum temporary footprints during O&M in both the wind farm sites and the cable corridors. This includes the use of jack-up vessels for major component replacement, cable repair and cable reburial works.

Table 5-7: Maximum temporary O&M footprints in the wind farm sites and cable corridors

Activity	Worst case scenario description	Footprint – DEP and SEP combined (m^2)
Jack-up vessel footprints for major maintenance activities (m^2/year)	Up to 10 jack-up movements per year for each of DEP and SEP (i.e. 20 in total). Jack-up vessel with a seabed footprint of 1,200m^2 (up to four legs/spudcans, each with a footprint of up to 300m^2).	24,000
Cable repair or replacement (m^2/10 years)	One export cable repair every 10 years, up to 800m, 3m disturbance width One interlink cable repair every 10 years, up to 800m, 3m disturbance width Two infield cable repairs every 10 years, up to 5km each, 3m disturbance width	34,800
Cable reburial (m^2/10 years)	Up to 200m per export cable subject to reburial works every 10 years, up to two export cables, 3m disturbance width Reburial of 1% of up to 154km of interlink cabling every 10 years (1.54km), 3m disturbance width Reburial of 1% of 225km of infield cabling every 10 years (2.25km), 3m disturbance width	12,570

5.4.2 Wind Turbines

5.4.2.1 Wind Turbine Parameters

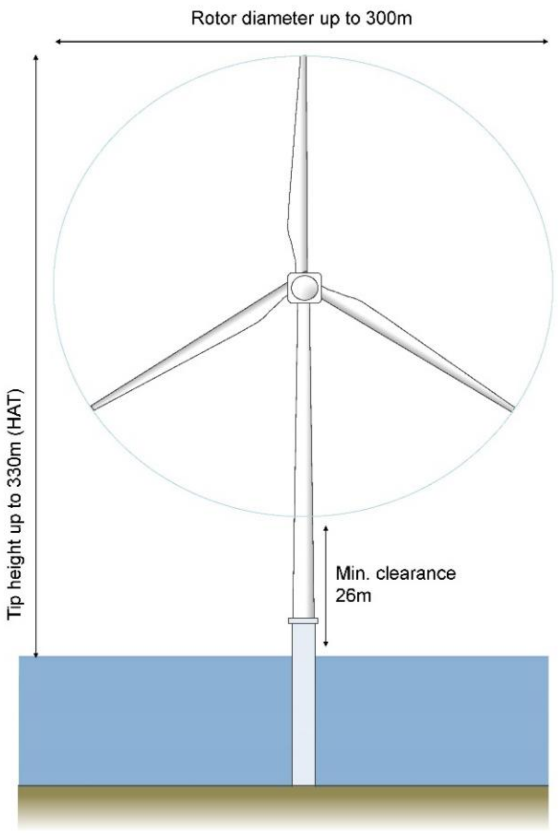
49. The project design envelope includes a range of turbines from 14MW to 26MW capacity in order to accommodate the ongoing rapid development in wind turbine technology. Accounting for this range and the assumed total capacity of DEP and SEP (448MW and 338MW respectively), there could be between 17 and 32 wind turbines at DEP and between 13 and 24 at SEP. Wind turbine parameters are summarised in **Table 5-8**: with key dimensions shown on

50. **Plate** 5-2.

Table 5-8: Key wind turbine parameters

Parameter	Minimum	Maximum
Rotor diameter (m)	220	300
Rated power (MW)	14	26
Units DEP	17	32
Units SEP	13	24
Rotor swept area DEP (km^2)	1.19	1.41
Rotor swept area SEP (km^2)	0.90	1.06
Rotor swept area total (km^2)	2.08	2.48
Tip height above Highest Astronomical Tide (HAT) (m)	246	330
Lower blade above HAT (the ‘air gap’) (m)	26	30
Rotor cut-in/cut-out wind speed (m/s)	3 to 35	3 to 35
Indicative separation distance between turbines (inter-row and in-row) (expressed as a multiplication of rotor diameter)	4.5	11
Indicative separation distance between turbines (inter-row) and between turbines in rows (in-row) (km)	0.99	3.3

Plate 5-2: Wind turbine schematic with key maximum dimensions & minimum clearance



5.4.2.2 Wind Turbine Layout

51. The wind turbine layout will not be finalised until much closer to the time of construction, following completion of detailed pre-construction wind resource studies, site investigations and the selection of the preferred turbines and their foundations. A layout will be selected from within the consented parameters to optimise energy output and the foundation installation process accounting for ground conditions. A key consideration for DEP and SEP will be the relationship with the existing wind farms at Dudgeon and Sheringham Shoal. The wake downstream of a turbine rotor is characterised by decreased wind speed and increased turbulence compared to the flow upstream of the rotor, and wake effects can be detected at a distance of up to 20 rotor diameters. An optimum layout will ensure that the flow in front of a wind turbine is affected as little as possible by wake effects from other wind turbines.

52. At this time, the layout can therefore only be described in general terms with the indicative separation distance between turbines as described in **Table 5-8**:. Inter-row spacing is the distance between the main rows of wind turbines and in-row spacing is the distance separating turbines in the main rows, which would be orientated to face the prevailing wind, or as close to this as is practical. In-row spacing and inter-row spacing may vary across the wind farm sites.

53. The layout will require Maritime and Coastguard Agency (MCA) approval prior to construction to minimise risk to surface vessels, including rescue boats and search and rescue aircraft, as per Marine Guidance Notice (MGN) 543 (MCA, 2016) (see **Chapter 15 Shipping and Navigation** and **Chapter 17 Aviation and Radar** for further details).

54. It is also possible that some areas of the wind farm sites will remain undeveloped (i.e. without wind turbines) due to constraints such as ground conditions or wind resource and wake effects. Where relevant, environmental factors such as visual appearance, shipping and navigation and ornithology will also be considered as part of the EIA process.

5.4.2.3 Wind Turbine Installation

55. The precise details of the installation process will be confirmed prior to construction however it will follow one of the methodologies outlined below (details of the pre-installation works are given in relation to the foundations, **Section 5.4.3**):

- Turbine components will be loaded on to the installation vessel (typically a jack-up vessel or an anchored floating vessel) at the marshalling base port. Blades, nacelles and towers for a number of turbines are likely to be loaded separately.
- The installation vessel will then transit to the DEP/SEP site and the components will be lifted by the vessel's crane onto the foundation or transition piece (TP) (depending on the foundation type being used). For each wind turbine, the tower would be installed first, followed by the nacelle, then the blades. Technicians will then fasten components together as they are lifted into place. Each wind turbine installation is likely to take in the order of one day, assuming no weather delays.
- Alternatively, the wind turbine components may be loaded onto barges or dedicated transport vessels at the marshalling base and installed by an installation vessel that remains on site throughout the installation campaign.
- It is also possible that complete wind turbines could be pre-assembled and commissioned onshore and transported to site for installation as a single unit.

56. The total duration of the installation campaign/s for the wind turbines is expected to be a maximum of 12 months (this may be across different campaigns for each project if they are developed separately).

57. Each installation vessel or barge may be assisted by a range of support vessels. These are typically smaller vessels that may be tugs, guard vessels, anchor handling vessels, or similar. These vessels will make the same general movements to, from and around the wind farm areas as the installation vessels that they are supporting. See **Section 5.4.8** for further details of vessel types, numbers and movements.

5.4.2.4 Wind Turbine Oils, Fluids and Materials

58. Wind turbines and the associated equipment require a number of oils, fluids and other materials for their safe use and operation. Biodegradable oils would be selected where possible, all chemicals used will be certified to the relevant standard and all wind turbines will have provision to retain any spilt fluids within the structure.

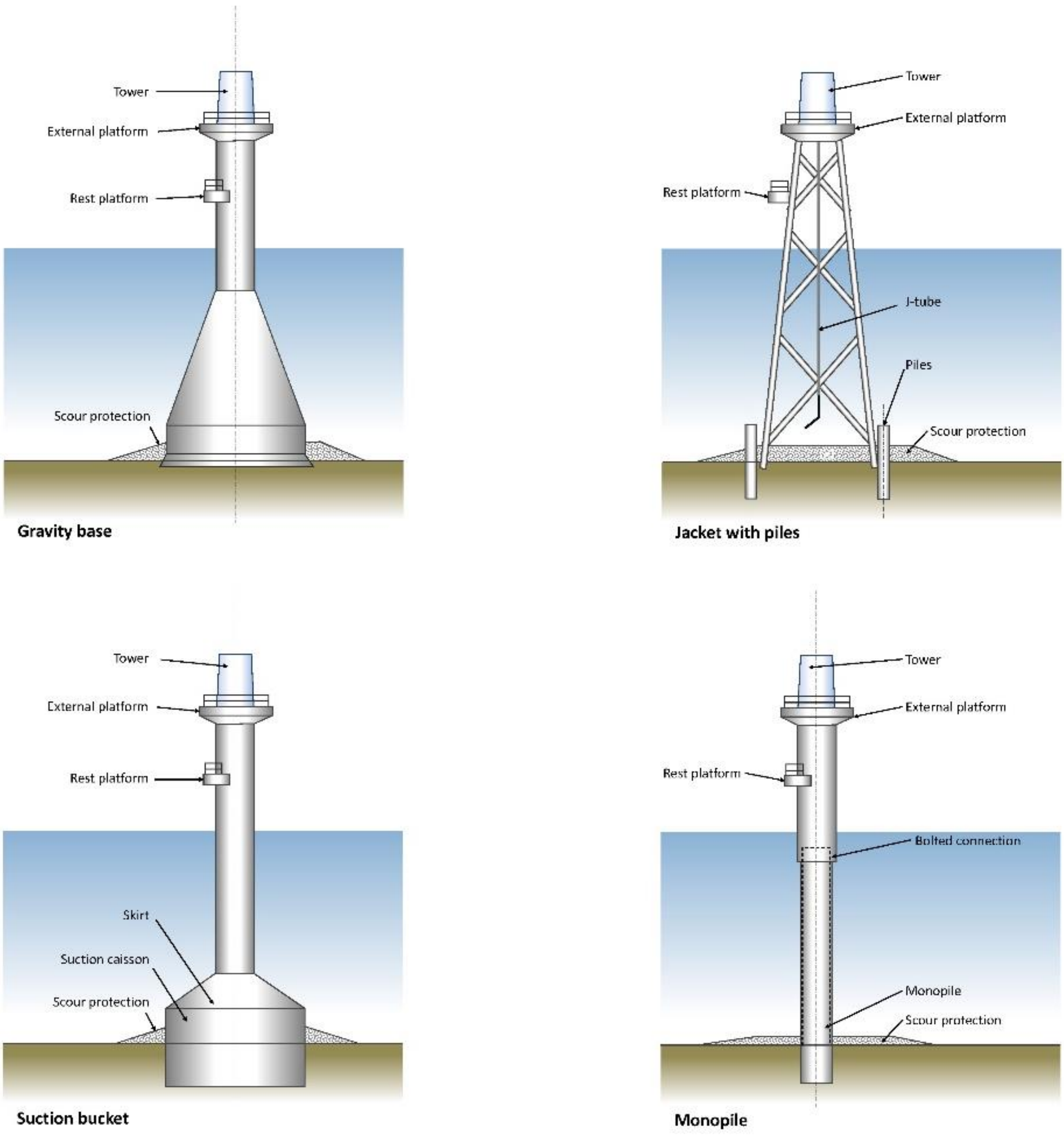
59. The required volume of oil and fluids will vary depending on the design i.e. conventional design or gearless, whether one or two or more rotor bearings are used in the design and the amount of redundancy designed into the system. Typical materials used include:

- Yaw grease;
- Yaw gear oil;
- Main bearing grease;
- Transformer (ester oil);
- Cooling fluid (water/glycol);
- Hydraulic oil;
- Pitch lubrication (grease);
- Pitch system hydraulic accumulators (nitrogen);
- Pitch gearbox oil;
- Gearbox oil; and
- Sulphur hexafluoride (SF6) gas.

5.4.3 Wind Turbine Foundations

60. The following sections describe the three foundation types under consideration for the wind turbines at DEP and SEP: monopiles, GBS and jackets (**Plate 5-3**), as well as details of the pre-installation works.

Plate 5-3: Examples of wind turbine foundation types



61. It is possible that more than one type of wind turbine foundation will be installed for DEP and SEP, accounting for the construction programme (i.e. when the Projects are constructed and whether they are constructed at the same time), ground conditions, water depth, wind turbine model and wind resource.

62. The foundations will be manufactured at an onshore facility and most likely delivered to site as fully assembled units with all ancillary structures attached. As with many aspects of the wind farm construction process, different logistical approaches are being explored within the industry as technologies and methodologies continue to evolve.

63. Fabrication and construction methods will depend on the foundation type selected, as described in the sections below.

5.4.3.1 Pre-installation works

64. Pre-installation works may include:

- Pre-construction surveys to confirm that the seabed is clear of any obstructions prior to installation activities commencing (including unexploded ordnance (UXO)) and to provide information to inform any micrositing of infrastructure, clearance operations, seabed preparation and for environmental monitoring purposes.
- UXO clearance requirements will be informed by the results of the pre-constructions surveys. Micrositing will be used to avoid UXO where possible, however where this is not the case, clearance may be required to safely remove or detonate any UXO that present a hazard to the construction activities or the ongoing operation of the wind farms. An example of UXO on the nearby Dudgeon OWF is shown in **Plate 5-4**. For context, 23 historic UXO were reported as part of the post-construction monitoring for the existing Dudgeon OWF, comprising projectile shells, a range of air dropped bombs from 250lb up to 2,000lb and sea mines (Wessex Archaeology, 2015). Low impact techniques will be used where possible e.g. low order deflagration, noting that UXO clearance works will be the subject of separate marine licence application/s prior to the start of construction.
- Boulder clearance – boulders that present an obstacle to the foundation installation process will be confirmed by the pre-construction surveys. The existing geophysical data suggests a relatively low number of boulders that could need to be relocated and it is likely that micrositing around many of these will be possible. Where this is not the case, large boulders (in the order of 5 m diameter and 1 m height) will be relocated to an adjacent area of seabed within the DEP and SEP boundaries where they do not present an obstacle to the works. Boulder clearance will be undertaken by subsea grab. Clearance of an estimated 20 boulders in SEP and 10 across both DEP North and DEP South, each of up to 5m in diameter, has been included in the assessments in order to be conservative. Temporary disturbance footprints are included in **Section 5.4.1.1**.
- For GBS, seabed preparation by dredging might be required to prepare a flat area of seabed prior to installation – see **Section 5.4.3.3.2** for further details.

Plate 5-4: Example of UXO (500lb German air dropped bomb) from the Dudgeon OWF

5.4.3.2 Monopiles

5.4.3.2.1 Overview and materials

65. The monopile is a large tubular structure on which a cylindrical transition piece can be fitted (**Plate 5-5** and **Plate 5-6**). The pile and/or transition piece may be tapered or change in diameter along their length. Monopiles may be fixed to the seabed in one of two ways: a suction bucket (caisson), or a single pile. The key parameters for monopile foundations are presented in **Table 5-9**.

66. Monopiles are fabricated from steel, with a number of secondary structures on the associated transition piece such as handrails, ladders, working platforms etc. that may be produced from a range of materials such as steel, concrete, aluminium, other metals and composites. The transition piece may be either steel or concrete.

Plate 5-5: A monopile foundation being installed at the Dudgeon OWF (Source: Equinor)

Plate 5-6: Monopile TPs ready for mobilisation to Dudgeon OWF (Source: Equinor)

Table 5-9: Monopile foundation parameters

Parameter	14MW	18+ MW
Maximum column diameter above sea surface (m)	9	14
Maximum column diameter in water column (m)	13	16
Maximum seabed diameter (suction bucket) (m)	36	45
Max footprint per suction bucket foundation structure (m^2)	1,017.90	1,590.40
Maximum penetration (piled solution) (m)	45	50
Maximum penetration (suction bucket) (m)	18	20
Maximum pile diameter (m)	13	16
Average drill arisings per foundation (m^3)	5,973	10,053
Maximum footprint on the seabed per foundation (excl. scour protection) (m^2)	1,784	2,702
Maximum outer scour protection diameter at sea bed (incl. foundation structure) (m)	49.40	60.80
Maximum area of scour protection per foundation (incl. structure footprint area) (m^2)	1,917	2,903
Maximum scour protection volume per foundation (m^3) (rock)	5,352	8,107
Maximum % requiring scour protection	100	100

5.4.3.2.2 Seabed preparation

67. Monopiles would be positioned in such a way to avoid the need for seabed preparation. If scour protection is required (see below) a filter layer would be installed prior to foundation installation to help prepare the seabed.

5.4.3.2.3 Installation

68. Steel monopiles foundations would typically be installed as follows:

- Delivery of monopile and transition piece to site via barge or by installation vessel. Monopiles can generally be installed with monohull floating construction vessels. Several exist in the market with the required crane capacities of 3,000 – 5,000 tonnes. Large jack-up vessels may also be used, however these have a more limited lifting capacity. It may also be possible to tow floated piles to site using tugs.
- Monopile up-ended by crane to vertical position and lowered to seabed.

- For a piled solution, driving hammer located onto top of pile using craneage, and monopile driven to required depth. Where ground conditions are difficult, it may also be necessary to carry out drilling using drilling equipment operated from the installation vessel before completing the driving.
- Lifting of transition piece onto top of monopile using craneage from installation vessel, levelling of transition piece and grouting of connection.
- Installation of scour protection.

69. A recent development for floating construction vessels is the possibility for installation using dynamic positioning (DP), although this is dependent on suitable water depth and ground conditions and at the time of writing this is not yet common practice. Operating in DP mode negates the need for anchoring operations and helps to speed up the installation process.

5.4.3.2.3.1 Pile driving

70. For the piling of monopile foundations, larger hammer spreads are more efficient and are likely to reduce the overall installation time and number of blows required to install each pile. However the actual energy output will be optimised to that required for successful installation. At the time of writing, 4,000kJ spreads are available although the expectation is that larger hammers in the region of 5,000kJ to 5,500kJ may become available prior to the start of construction of DEP and SEP, and may be needed for larger diameter piles. A drivability assessment will be carried out prior to construction when further information is available regarding the ground conditions, to determine the required piling requirements (e.g. hammer energy and blow rate).

71. At this stage, the maximum hammer energy used for monopile installation is assumed to be 5,500kJ for the largest 16m diameter monopiles. Each piling event would commence with a soft-start at a lower hammer energy, followed by a gradual ramp-up for at least 20 minutes to the maximum hammer energy required. The maximum hammer energy is only likely to be required at a few of the piling installation locations.

72. As an alternative to traditional impact piling, the feasibility of vibration piling will also be explored pre-construction. Vibration piling is not yet a proven technique for offshore wind foundations but is included in the design envelope to allow for future technology developments. Even if feasible, it is likely that it could only be used for part of the installation of each pile, with impact piling being required to complete the installation. As such, the worst case scenario for assessment purposes is reflected by the impact piling parameters.

73. The key impact piling parameters (worst case) are described in **Table 5-10**:. Further information describing the detailed piling parameters used to inform the assessment, including the underwater noise modelling are provided in **Chapter 11 Fish and Shellfish Ecology** and **Chapter 12 Marine Mammal Ecology**.

Table 5-10: Monopile piling parameters for wind turbines

Parameter	Value
Maximum diameter (m)	16
Maximum hammer energy (kJ)	5,500

Parameter	Value
Indicative pile depth (m)	45
Total piling time per foundation (hr) (includes soft-start and ramp-up, and providing allowance for issues such as low blow rate, refusal, etc.)	4

5.4.3.2.3.2 Pile drilling

74. Whilst pile driving is the most likely installation method, in the event that ground conditions are not suited to piling, monopiles may be drilled, or both drilled and driven, into the seabed. For this purpose, it is estimated that up to 5% of the wind turbine locations could need drilling i.e. up to two for each of DEP and SEP. For a 14MW turbine, requiring a drill diameter of 13m and a drill penetration depth of 45m, the amount of monopile drill arisings would be approximately 5,973m^3 per foundation, or a total of 23,892m^3 for DEP and SEP combined.

75. The drill arisings (spoil) would be disposed of adjacent to the foundation location, above or slightly below the sea surface, from where they would be expected to settle onto the seabed in the immediate vicinity of each foundation (see **Chapter 8 Marine Geology, Oceanography and Physical Processes** for further details).

5.4.3.2.4 Scour protection

76. Monopiles normally require rock installation for scour protection, although the exact requirements will not be confirmed until prior to the start of construction. Purpose made vessels are used to accurately install rock, which is normally completed using a fall-pipe lay system.

77. Scour protection would likely consist of two gradings of quarried rock: one for the filter layer and one for the armour layer. Rock for the outer armour layer would typically be well graded with d_{50}=200 to 400 (i.e. half the stones would be less than a specified median (200 to 400mm diameter) and half would be greater).

78. Other scour protection systems including frond systems and grouted mattresses are under development in the market and, subject to availability at the time of construction, would be evaluated for the actual design case taken forward.

79. The maximum diameter, area and volume requirements for scour protection per foundation are provided in **Table 5-9**.

5.4.3.3 Gravity Base Structures

5.4.3.3.1 Overview and materials

80. GBS foundations typically comprise the base itself, a lower conical section and an upper cylindrical section. The shape and size can vary widely, with buoyant structures being significantly larger in size. Buoyant structures offer the advantage of being able to be floated or semi-floated to the wind farm sites with the assistance of a barge or pontoon (see **Section 5.4.3.3.3** below).

81. Gravity base structures might also use a skirt at their base that penetrates the seabed, adding stability. The penetration could vary from around 0.1 to 5m. Under base grouting may also be used to strengthen the soil beneath the foundation and to fill small voids between the foundation and the seabed.

82. The key parameters for GBS foundations are presented in **Table 5-11**.

83. GBS are generally fabricated from steel reinforced concrete, ballasted with locally sourced marine aggregate (sand). Secondary structures such as handrails, ladders, working platforms etc. may be produced from a range of materials such as steel, concrete, aluminium, other metals and composites.

Table 5-11: GBS foundation parameters

Parameter	14 MW	18+ MW
Maximum column diameter at water level (m)	11	14
Maximum column diameter in water column (shaft) (m)	30	40
Maximum seabed diameter (base plate) (m)	45	60
Maximum penetration below mud line (m)	6	6
Maximum footprint on the seabed per foundation (excl. scour protection) (m^2)	1,590	2,827
Maximum outer scour protection diameter at sea bed (incl. foundation structure) (m)	135	180
Maximum area of scour protection per foundation (incl. structure footprint area) (m^2)	14,314	25,447
Maximum scour protection volume per foundation, including gravel bed (m^3) (gravel and rock)	35,785	63,617
Maximum % GBS requiring scour protection	100	100
Maximum diameter of gravel footing per foundation (m)	47	62
Indicative volume of gravel footing per foundation (m^3)	3,470	6,038
Maximum dredge volume for seabed preparation, up to 5m depth (m^3)	16,592	25,133
Maximum footprint for seabed preparation (m^2)	1,735	3,019
Indicative maximum volume of gravel for seabed preparation purposes per foundation (m^3)	9,543	16,965

5.4.3.3.2 Seabed preparation

84. The size and weight of the GBS foundation combined with the natural variability of the seabed within the wind farm sites result in three scenarios for potential seabed preparation works, as follows:

- No seabed preparation;
- Place a gravel pad of between 1.5m and 3m in height and 60m in diameter (bedding layer); or

- Dredge up to 5m depth and back fill with gravel up to 1m above mudline (levelling layer).

85. Where required, dredging works are likely to be carried out using a trailer suction hopper dredger (TSHD), with the gravel installed by a dynamically positioned fall pipe vessel. Dredged sediments would be deposited in the near vicinity of each foundation, and all within the project boundaries, although the feasibility of re-using the material as ballast for the GBS may also be explored.
86. Dimensions and volumes are given in **Table 5-11**:.

5.4.3.3.3 Installation

87. GBS would be delivered to site via one of two methods, depending on the foundation design:
    - Transported to site by barge and installed by heavy lift crane (either a jack-up vessel or floating vessel); or
    - For floating types, towed to site and sunk via ballasting.
88. The overall installation methodology would typically be as follows:
    - Where necessary, undertake seabed preparation activities as described above;
    - Transport GBS to site;
    - Mobilise heavy lift floating crane (if foundation is a non-buoyant solution);
    - Lift foundation from barge and lower to prepared area of seabed, or adjust buoyancy of floating foundation and sink to prepared area of seabed;
    - Install backfill as necessary; and
    - Install scour protection (details below).

5.4.3.3.4 Scour protection

89. As described for monopiles, GBS will normally require rock installation for scour protection, although the exact requirements will not be confirmed until prior to the start of construction. For the purpose of the assessment, it is assumed that 100% of GBS will require scour protection. The installation methodologies and type of scour protection systems that might be used are as described in **Section 5.4.3.2.4**.
90. The maximum diameter, area and volume requirements for scour protection per foundation are provided in **Table 5-15**.

5.4.3.4 Jackets

5.4.3.4.1 Overview and materials

91. If jacket foundations are used for the wind turbines, each will have up to four legs with the footing for each leg secured to the seabed with either a single pile, one suction bucket, a jack-up foot or with up to two screw piles. In the case of a single pile solution, the piles may be either driven or drilled, or a combination of the two (see **Section 5.4.3.4.3**).
92. The key parameters for jacket foundations (worst case) are presented in **Table 5-12**:.

93. Jackets are primarily fabricated from steel. Secondary structures such as handrails, ladders, working platforms etc. may be produced from a range of materials such as steel, concrete, aluminium, other metals and composites.

Table 5-12: Jacket foundation parameters (wind turbines)

Parameter	14 MW	18+ MW
Jacket width at LAT (m)	28	35
Maximum overall width of jacket at tower interface (m)	23	30
Maximum height of foundation main access platform floor above HAT (m)	22	22
Maximum seabed footprint per jacket (m^2) (based on a suction bucket design), excl. scour protection	1,018	1,257
Maximum number of piles per jacket	4	4
Average drill arisings per jacket (m^3)	1,414	2,309
Maximum scour protection diameter at seabed level, per leg (based on a suction bucket or piled design and including the foundation structure) (m)	12	14
Maximum area of scour protection per jacket (m^2) (based on a suction bucket or piled design)	3,054	3,770
Maximum seabed footprint per jacket (m^2) (based on a suction bucket or piled design), incl. scour protection	4,072	5,027
Maximum scour protection volume per jacket (m^3) (rock)	9,161	11,310

5.4.3.4.2 Seabed preparation

94. Jacket foundations would be positioned in such a way to avoid the need for seabed preparation. If scour protection is required (see below) a filter layer would be installed prior to foundation installation to help prepare the seabed.

5.4.3.4.3 Installation

95. As described above, jacket foundations may be fixed to the seabed either with piles (driven and/or drilled, or screw piles), jack-up footings or suction buckets. The key impact piling parameters for pin piles (worst case) are described in **Table 5-13**:, with further details presented in **Chapter 11 Fish and Shellfish Ecology** and **Chapter 12 Marine Mammal Ecology**.

96. As described for monopiles, the feasibility of vibration piling will also be explored pre-construction but remains an unproven technique for offshore wind foundations and therefore the worst case scenario for assessment purposes is impact piling.

97. Whilst considered unlikely, in the event of drilling being required due to unsuitable ground conditions for pile driving, the jacket pin piles may be drilled or drilled-driven into the seabed. For this purpose, it is estimated that up to 5% of the wind turbine locations could need drilling i.e. up to two for each of DEP and SEP. For a 14MW turbine, requiring a drill diameter of 3m and an average drill penetration depth of 50m, the amount of pin pile drill arisings would be approximately 1,414m^3 per jacket, or a total of 5,656m^3 for DEP and SEP combined.

98. As with monopiles, drill arisings would be disposed of adjacent to the foundation location, above or slightly below the sea surface, from where they would be expected to settle onto the seabed in the immediate vicinity of each foundation (see **Chapter 8 Marine Geology, Oceanography and Physical Processes** for further details).

99. Jackets are most likely to be installed using floating monohull construction vessels, with the jackets either transported and lifted directly from the vessel deck, or transported to site by barge and lifted into place by a crane vessel.

Table 5-13: Jacket foundation piling parameters (wind turbines)

Parameter	18+ MW
Maximum pile diameter (m)	4
Maximum hammer energy (kJ)	3,000
Indicative pile depth (m)	60
Total piling time per pin pile (hr) (includes soft-start and ramp-up, and providing allowance for issues such as low blow rate, refusal, etc.)	3
Total piling time per jacket (hr) (up to 4 piles each)	12

5.4.3.4.4 Scour protection

100. Scour protection may be required around the base of the foundations to protect against localised erosion of the seabed.

101. The types of scour protection that could be used include:

- Rock or gravel placement;
- Concrete mattresses;
- Flow energy dissipation devices (used to describe various solutions that dissipate flow energy and entrap sediment, and including options such as frond mats, mats of large linked hoops, and structures covered with long spikes). It is noted that these technologies are often only appropriate for use in areas with significant mobile seabed sediments, and examples such as the spiked designs are only appropriate for use in areas which are not trawled;
- Protective aprons or coverings (solid structures of varying shapes, typically prefabricated in concrete or high-density plastics); and
- Bagged solutions, (including geotextile sand containers, rock-filled gabion bags or nets, and grout bags, filled with material sourced from the site or elsewhere).

102. The installation method will depend on the scour protection system selected. Rock would be placed by dynamically positioned fall pipe vessel, whilst the other options would be more suited to the use of a smaller crane vessel or similar.

103. The maximum diameter, area and volume requirements for scour protection per jacket are provided in **Table 5-12**:.

5.4.4 Offshore Substation Platforms

104. The cables from each string of turbines will be brought to an OSP, located appropriately to optimise the infield, interlink and export cable lengths. At the OSP, the generated power will be transformed to a higher AC voltage of up to 220kV.

105. There will be up to two OSPs, depending on how DEP and SEP are developed, as described in **Section 5.1.1**. In the case that two OSPs are constructed there will be one located in each extension area i.e. one in DEP and one in SEP. The location of the OSP/s will be confirmed during the detailed design process, accounting for the wind turbine layout, but will be within the order limits of each wind farm site.

106. The basic OSP design will consist of a topside structure configured in a multiple deck arrangement, with the decks either open with modular equipment, or fully clad. Weather sensitive equipment would be housed accordingly. Equipment and facilities may consist of:

- High voltage (HV) power transformers;
- HV switchgear and busbars;
- Substation auxiliary systems and LV distribution;
- Instrumentation, metering equipment and control systems;
- Standby generators;
- Shunt reactor(s);
- Auxiliary and uninterruptible power supply systems;
- Navigation, aviation and safety marking and lighting;
- Systems for vessel access and/or retrieval;
- Potable water supply;
- Black water separation;
- Storage (including stores, fuel, and spares); and
- Communication systems and control hub facilities.

107. It is likely that only a minor platform crane will be required and no helideck, although the design may allow for ‘lift-off’ (i.e. of equipment) by helicopter.

108. Indicative maximum design parameters (based on the scenario with a single larger OSP serving both DEP and SEP) are a topside weight up to 4,000Te, topside width up to 40m and length up to 70m. The indicative maximum topside height is 50m above HAT. An example OSP (from Dudgeon OWF) is shown in **Plate 5-7**.

Plate 5-7: Dudgeon OWF OSP being mobilised for installation (Source: Equinor)

5.4.4.1 Offshore Substation Platform Foundations

5.4.4.1.1 Overview and materials

109. The OSP foundation type will be a jacket, as installed, for example, at the Dudgeon OWF (**Plate 5-8**). The jacket will have up to four legs and will be secured to the seabed with either up to two piles at each leg, or one suction 'bucket' (termed a caisson) at each leg. In the case of a piled solution, the piles may be either driven or drilled, or a combination of the two. The key OSP foundation parameters (worst case) are detailed in **Table 5-14**.

Plate 5-8: OSP jacket at Dudgeon OWF (Source: Equinor)

Table 5-14: OSP foundation parameters

Parameter	Value
Jacket width (m)	30
Jacket length (m)	30
Maximum seabed footprint per OSP (m^2) (based on a suction bucket design, 12m diameter), excl. scour protection	452
Maximum number of piles per jacket	8
Average drill arisings per OSP (m^3) (based on 1 pile per OSP requiring drilling)	425
Maximum area of scour protection per OSP (m^2) (based on a suction bucket design and including the footprint of the suction buckets)	1,662
Maximum seabed preparation area per jacket (m^2)	Not required

110. The jacket foundation will mainly be comprised of steel. However, it is possible that some secondary structures, such as handrails, gratings and ladders, could be produced using other metals, such as aluminium, or composites. Also, concrete could be used to form the working platform.

111. Some of the equipment at the OSP would contain fluids. The key types of fluids that may be used include:

- Diesel fuel for the emergency generators (in diesel storage tanks);
- Oil for the transformers (oil will be monitored and filtered, top-up may be required);
- Engine oil;
- Glycol;
- Sewage and grey water;
- Lead acid contained within batteries; and
- SF6.

112. The OSP design will include self-contained bunds to collect any possible oil spill. Transfer of oil/fuel between the OSP and service vessels will follow best practice procedures, with additional procedures in place should there be a spill to the marine environment.

113. Any oil spillage would be collected in a separate oil waste tank. Both oil waste and other wastes (waste water etc.) would be brought to shore in a secure container and disposed of according to industry best practice procedures.

114. All other waste streams would be processed on the OSP or transferred to shore as required.

5.4.4.1.2 Installation

115. Topside installation may be by any of the following methods:

- Crane vessel (or vessels working together) in a single lift;
- Crane vessel (or vessels working together) in separate lifts of deck and sub-modules;
- Rail-skid transfer from a large jack-up; or
- Self-installing.

116. As described in **Section 5.4.4.1**, the jacket foundation legs may be fixed to the seabed either with piles or suction buckets. Piling of the jacket would be as described for the wind turbine foundations (**Section 5.4.3.4.3**), with the key parameters (worst case) described in **Table 5-15**. Seabed preparation is not considered necessary for the OSP jacket foundations.

117. As with the other piled foundation solutions and whilst considered unlikely, in the event of drilling being required, the OSP jacket pin piles may be drilled or drilled-driven into the seabed. For this purpose, it is assumed that drilling may be required for both OSPs, but only at one pile at each. In this manner, the amount of pin pile drill arisings would be approximately 425m^3 per OSP, or a total of 850m^3 for DEP and SEP combined (i.e. two OSPs).

118. Drill arisings would be disposed of adjacent to the foundation location, above or slightly below the sea surface, from where they would be expected to settle onto the seabed in the immediate vicinity of each foundation (see **Chapter 8 Marine Geology, Oceanography and Physical Processes** for further details).

Table 5-15 OSP piling parameters

Parameter	Value
Maximum pile diameter (m)	3.5
Maximum hammer energy (kJ)	3,000
Indicative pile depth (m)	60
Total piling time per pin pile (hr) (includes soft-start and ramp-up, and providing allowance for issues such as low blow rate, refusal, etc.)	3
Total piling time per jacket (hr) (up to 8 piles each)	24

5.4.4.1.3 Scour Protection

119. Scour protection may be required around the base of the foundations to protect against localised erosion of the seabed. The types of scour protection that could be used and installation methods are as described for the wind turbine jacket foundations (**Section 5.4.3.4.2**). In the case of a piled solution, a radius of scour protection of up to 6m may be required for each leg, equating to a total area of up to 452m^2 for all four legs. For a jacket foundation with suction buckets, a radius of scour protection of up to 11.5m may be required for each leg, equating to a total area of up to 1,662m^2 for all four legs.

5.4.5 Underwater Noise

120. A number of activities during the construction, operation and decommissioning of DEP and SEP will result in underwater noise. The most significant noise sources are likely to be piling of the foundations and clearance of UXO. An underwater noise modelling study has been undertaken in support of the assessment and is provided in **Appendix 12.2**.

5.4.6 Navigation Lighting Requirements and Colour Scheme

121. With respect to lighting and marking, the wind turbines and OSP topsides will be designed and constructed to satisfy the requirements of the Civil Aviation Authority (CAA), MCA and Trinity House Lighthouse Service (THLS).

122. Further details including reference to the relevant guidance and regulations is presented in **Chapter 15 Shipping and Navigation** and **Chapter 17 Aviation and Radar**.

123. The colour scheme for nacelles, blades and towers is expected to be RAL 7035 (light grey) and foundation steelwork RAL 1023 (traffic yellow) from HAT up to a minimum of 15m.

5.4.7 Electrical Infrastructure – Cables

124. The electrical transmission system will collect the power produced at the wind turbines and transport it to the UK electricity transmission network. The transmission system will be constructed by the Applicant and the ownership will be transferred to an Offshore Transmission Owner (OFTO) in accordance with applicable rules and regulations in a transaction managed by the Office of Gas and Electricity Markets (Ofgem).

125. The electrical cables that make up the offshore transmission system include: offshore export cables (linking the OSP/s to the landfall); interlink cables (linking two separate wind farm areas); and infield cables (linking the wind turbine generators to the OSP/s). These are described in the following sections.

5.4.7.1 Offshore Export Cables

126. There will be up to two HVAC offshore export cables, with each forming a circuit consisting of a 3-core power cable with an integrated fibreoptic cable. The power cable voltage will be between 220kV and 230kV, with an indicative external cable diameter of 235mm to 300mm.

127. The length of the export cables depends on the development scenario in question (**Table 5-16**:). In the event of one OSP at SEP (which could apply either to SEP in isolation or for DEP and SEP together under the integrated grid option) the export cable length will be up to 40km (per cable), measured from the OSP to landfall. For the integrated grid option with a single OSP at SEP, the cables connecting DEP and SEP would be interlink cables (described in **Section 5.4.7.2**), however a second export cable would be required between SEP and the landfall giving a maximum total length accounting for two export cables of 80km.

128. For DEP in isolation, the maximum length of export cable measured from an OSP in DEP North to landfall (per cable) is 62km. For the DEP and SEP together scenario with a separate OSP at DEP North (separated grid option), one export cable would run from DEP North via SEP to the landfall (62km) and a second export cable would run from SEP to the landfall (40km). Therefore the maximum total length of export cables in this scenario would be 102km.

129. The offshore export cable/s make landfall at Weybourne, where they will be connected to the onshore cables in a transition joint bay, having been installed under the intertidal zone by HDD.

130. Each offshore export cable will be installed in a separate trench with a spacing of up to 100m between the cables, where two export cables are installed in parallel. For the purpose of the DCO application and environmental assessment, an offshore export cable corridor has been defined in order to encompass both cables and the adjacent area of seabed that may be subject to temporary works, such as anchoring or the use of jack-up vessels. The offshore export cable corridor provides space for the installation works and any future operation and maintenance activities such as cable reburial or repairs (details in **Section 5.4.10**). The offshore export cable corridor is 500m wide, but funnels out to up to 1,000m on approach to the landfall and through the Cromer Shoal Chalk Beds MCZ. The greater width of corridor on approach to landfall is designed to provide greater flexibility in the detailed routeing of the export cable/s at the pre-construction stage.

131. There is no planned jointing of cables along the offshore export cable route as the required length of cable can be manufactured without the need for offshore joints and can be loaded onboard several installation vessels in the market with sufficient cable loading capacity.

Table 5-16: Offshore export cable parameters

Parameter	**Details**			
	DEP in isolation	**SEP in isolation**	**DEP & SEP together – 1 OSP at SEP**	**DEP & SEP together – 1 OSP at SEP and 1 OSP at DEP North**
Maximum length of export cable measured from OSP to landfall (per cable) (km)	62	40	40	SEP: 40 DEP: 62
Maximum length of export cable measured from OSP to landfall (all cables) (km)	62	40	80	102
Export cable corridor width outside MCZ (m)	500			
Export cable corridor width inside MCZ to landfall (m)	Approximately 1,000			
Maximum number of export cables	1	1	2	2
Maximum number of trenches	1	1	2	2
Spacing between cables in trenches (m)	n/a	n/a	Up to 100	Up to 100
Export cable operating voltage (kV)	220 – 230			

5.4.7.2 Interlink Cables

132. In the event that one OSP is constructed for DEP and SEP together (most likely being located at SEP), interlink cables will connect DEP North to SEP, and possibly also DEP South to SEP. If DEP is developed in isolation, an OSP will be constructed at DEP North, and interlink cables would connect DEP South to DEP North, assuming that both DEP wind farm sites are developed. Interlink cable parameters are set out in **Table 5-17**: with the total interlink cable lengths for each development scenario summarised in **Table 5-18**:.

133. The interlink cable voltage will be up to 110kV AC, with an indicative external cable diameter of between 110mm and 180mm. They will be integrated with fibre optic cables.

134. Each interlink cable will be installed in a separate trench with a spacing of up to 100m between the cables. For the purpose of the environmental assessment, interlink cable corridors have been defined in order to encompass the cables and the adjacent area of seabed that may be subject to temporary works, such as anchoring or the use of jack-up vessels. As with the export cables, the corridor provides space for the installation works and any future operation and maintenance activities such as cable reburial or repairs (details in **Section 5.4.10**). The interlink cable corridors are 500m wide going from DEP South (i.e. from DEP South to DEP North and from DEP South to SEP), and 1,000m from DEP North to SEP.

Table 5-17: Interlink cable parameters

Parameter	Details
Maximum length of interlink cable DEP North to SEP (in the event of no separate OSP at DEP North) (per cable) (km)	22
Maximum length of interlink cable DEP South to SEP (in the event of no separate OSP at DEP North) (per cable) (km)	16.5
Maximum length of interlink cable DEP South to DEP North (per cable) (km)	22
Interlink cable corridor width – DEP South to DEP North or DEP South to SEP (m)	500
Interlink cable corridor width – DEP North to SEP (m) N.B. corridor width is 500m in the case of a separate OSP at DEP North, in which case it is defined as an export cable corridor as described in **Table 5-16**:	1,000
Maximum number of interlink cables DEP North to SEP (1 OSP at SEP and assuming only DEP North is developed)	7
Maximum number of interlink cables DEP South to DEP North	3
Maximum number of interlink cables DEP South to SEP	3

Parameter	Details
Maximum number of trenches	Up to 1 trench per cable
Spacing between interlink cables in trenches (m)	Up to 100
Maximum interlink cable voltage (kV)	110

Table 5-18: Maximum interlink cable lengths for each development scenario

Development scenario	Interlink cable length[3] (all cables) (km)	Notes

Integrated grid option:
 	
DEP & SEP together – 1 OSP at SEP (assuming both DEP North and DEP South are developed)
	5 x 20 +10% = 110
	
	2 x 15 +10% = 33
	
	Total = 143
		• Up to 5 cables between DEP North and SEP; and
		• Up to 3 cables between DEP South and SEP.
		• However, figures allow for one cable for contingency purposes with the maximum total number of cables being 7:
		  ○ If contingency is in DEP North, DEP South has only 2 cables (5 + 2 = 7)
		  ○ If contingency is in DEP South, DEP North has only 4 cables (3 + 4 = 7)
		• DEP North to SEP is the longest route (22km) therefore the greatest number of these cables is the worst case.

Integrated grid option: DEP & SEP together – 1 OSP at SEP (assuming only DEP North is developed)	7 x 20 +10% = 154	Up to 7 cables between DEP North and SEP
Separated grid option:	3 x 20 +10% = 66	Up to 3 cables between DEP South and DEP North (cable from DEP

[3] Interlink cable lengths include a 10% contingency for final design purposes

Development scenario	Interlink cable length[3] (all cables) (km)	Notes
DEP & SEP together – 1 OSP at SEP and 1 OSP at DEP North (assuming both DEP North and DEP South are developed)		North, past SEP and to the landfall is an export cable).
Separated grid option: DEP & SEP together – 1 OSP at SEP and 1 OSP at DEP North (assuming only DEP North is developed)	0	No interlink cables in this scenario (export cables only).
DEP in isolation (assuming both DEP North and DEP South are developed)	3 x 20 +10% = 66	Up to 3 cables between DEP North and DEP South.
SEP in isolation	0	No interlink cables in this scenario.

5.4.7.3 Infield (Array) Cables

135. Infield cables link the wind turbine generators to the OSP/s. Cable system design will be based on radial strings from the OSP/s and connecting multiple turbines per string. The number of infield cables will be equal to the number of turbines, whilst the length of each cable, and string, will depend on the distance between the turbines and the distance between the first turbine on the string and the OSP (**Table 5-19**:).

136. The infield cables will be 110kV AC, with an indicative external cable diameter of between 110mm and 180mm. Cable circuits (strings) will be optimised according to the electrical load they are required to carry, with up to three different cable dimensions being used. They will be integrated with fibre optic cables.

137. Each infield cable will be installed in its own trench, with the maximum length of infield cables being 225km.

Table 5-19: Infield cable parameters

Parameter	Details		
	DEP	SEP	Combined
Maximum length of infield cables (km)	135 (90 at DEP N and 45 at DEP S)	90	225
Maximum number of infield circuits (strings)	6	6	15
Number of infield cables per circuit	Up to 6	Up to 6	Up to 6
Maximum infield cable voltage (kV)	110	110	110

5.4.7.4 Cable Installation Methods

5.4.7.4.1 Pre-lay Works

138. Pre-construction surveys, UXO clearance and boulder clearance (where required) will be undertaken as described for the foundations (**Section 5.4.3.1**).

139. The estimated seabed footprint resulting from boulder clearance is included in **Section 5.4.1.1**. The existing geophysical data suggests a relatively low number of boulders that could need to be relocated and it is likely that micrositing around many of these will be possible. However, clearance of an estimated 20 boulders in the export cable corridor, each of up to 5m in diameter, has been included in the assessments in order to be conservative. All boulders would be relocated within the project boundaries by subsea grab.

5.4.7.4.1.1 Removal of existing out of service cables

140. The disused Stratos telecommunications cable makes landfall near Weybourne and is inside the offshore export cable corridor as it approaches the landfall (see **Chapter 18 Petroleum Industry and Other Marine Users** for details).

141. Where the cable routes cross any such cable, depending on the length of cable and burial depth, these will either be recovered from the seabed by grapple hook or similar method prior to the start of installation, or cut at an appropriate distance either side of the cable and the free ends secured to the seabed by clump weights.

5.4.7.4.1.2 Pre-lay grapnel run

142. Before cable-laying operations commence, it must be ensured that the route is free from obstructions such as discarded fishing gear, anchors or abandoned cables, wires and ropes that may be identified as part of the pre-construction surveys (e.g. **Plate 5-9**). A survey vessel would be used to undertake a pre-lay grapnel run (PLGR) to clear all such identified debris.

143. The width of seabed disturbance along the pre-grapnel run is estimated to be up to 3m, which would be encompassed by the maximum footprint of cable installation works – see **Section 5.4.7.5.4** for further details.

Plate 5-9: Example of seabed debris (an abandoned anchor) found in the Dudgeon OWF site (Source: Equinor)

5.4.7.4.1.3 Pre-sweeping

144. Areas of mobile seabed (typically manifest either in sand waves or megaripples) may present a risk to the cable burial process either by preventing the cable burial tools from operating efficiently or by resulting in exposure and scouring of the cable once installed. In cases this could result over time in the cable being left ‘free-spanning’ over the seabed. Free spanning cables present a risk to other marine users and result in a large amount of strain being placed on the cables, significantly increasing the chance of their failure and the subsequent need for repair works.

145. In order to prevent this, cables can be placed where possible in the troughs of sand waves to the reference seabed level, which would minimise the potential for cables becoming unburied. However, where this is not possible, the alternative is to dredge the top of the sand waves prior to installation down to the seabed reference level. This process is termed pre-sweeping (also referred to as seabed levelling) and would be completed before the cable is laid on the seabed.

146. Analysis of the project geophysical data collected in 2020 has identified four areas that may require pre-sweeping, as shown on **Figure 5.8** and described in **Table 5-20**:. These include: a portion of the interlink cable corridor from SEP, as it joins the DEP North wind farm site; an adjacent area within DEP North; a portion of the interlink cable corridor between DEP North and DEP South, as it exits DEP North; and an area within DEP South where the interlink cable corridor/s join the wind farm site.

147. The area affected by the works will vary between 50m and 100m in width depending on the cable corridor in question and the number of cables. The seabed footprint and volume of sediment affected due to pre-sweeping is described in **Table 5-20**, with a total seabed footprint of 929,719m^2 across all four areas and a total volume of up to 376,400m^3. Excavated sediment will be redeposited within the wind farm sites and/or cable corridors.

Table 5-20: Cable route pre-sweeping footprints and volumes

Area ID and location	Pre-sweep corridor width (m)	Seabed footprint (m^2)	Dredge volume (m^3)
Area 1: SEP to DEP N interlink	100	337,495	144,200
Area 2: DEP N to DEP S interlink	50	119,391	44,300
Area 3: DEP S	100	301,935	171,700
Area 4: DEP N	50	170,898	16,200
Total	**-**	**929,719**	**376,400**

5.4.7.5 Cable Burial

148. The purpose of cable burial is to ensure that the cables are protected from damage, either from other activities such as fishing and shipping, or from naturally occurring physical processes acting on the seabed. Typical burial depth for DEP and SEP cables, excluding in areas of sand waves, is expected to be between 0.5m to 1.5m (or up to 1m for the export cables), but in challenging ground conditions the cables may not be buried at all. In this event, the installation of external cable protection would be considered.

149. Cable burial requirements for the purpose of the environmental assessment have been informed through the completion of a draft export cable burial risk assessment (Pace Geotechnics, 2020) which has been produced by the Applicant at an early stage to inform the design and environmental assessment processes on advice from relevant stakeholders. This study has drawn on the data and lessons learnt from the cable burial process for the nearby Dudgeon and Sheringham Shoal OWFs. The burial requirements will be finalised based on an assessment of the risks posed to the project in specific areas, following the completion of detailed pre-construction geotechnical and geophysical investigations and the subsequent finalisation of the cable burial risk assessment prior to the start of construction. Furthermore, an outline Cable Specification, Installation and Monitoring Plan for the MCZ (CSIMP) will be submitted alongside the DCO application which will demonstrate how the proposed export cable installation works in the MCZ will be controlled by the DCO and give greater confidence to the assumptions underpinning the assessments.

150. Burial of the offshore cables will be through any combination of ploughing, jetting or mechanical cutting, however infield cable burial is more likely to be undertaken by jetting or mechanical cutting. The dimensions of the cable trenches (where applicable) and the overall seabed footprint affected by the burial process will depend on the installation method. Details are provided in **Section 5.4.7.5.4** below and summarised in **Section 5.4.1.1**.

151. The export cables will be installed in separate installation campaigns as the installation vessel only can install one cable at a time (i.e. no bundle lay with HVAC cables).

5.4.7.5.1 Ploughing

152. A plough uses a forward blade to cut through the seabed, while burying the cable behind it. Ploughs can be used as a pre-trench tool (i.e. the cables are laid into a trench for later backfilling), a post-lay burial tool (i.e. the cable is first laid in position on the seabed before being ploughed in) or, more commonly, as a simultaneous lay and burial tool. Ploughing tools can be pulled directly by a surface vessel or can be mounted onto self-propelled caterpillar tracked vehicles which run along the seabed taking power from a surface vessel. The plough inserts the cable into the seabed as it moves. Indicative dimensions of a large plough are 15m x 6.5m x 7m.

153. There are two types of plough: displacement and non-displacement. The difference is important in terms of understanding the effect on the seabed. Displacement ploughs are typically used to pre-cut a trench in hard ground conditions, creating a trench that remains open for subsequent cable installation. A second backfilling pass of the plough is then undertaken to bury the cable.

154. By contrast, a non-displacement plough (**Plate 5-10**) is designed to trench and bury the cable in a single pass, consequently causing less disturbance on the seabed as part of either a simultaneous or post lay and burial process. The plough may be fitted with additional equipment to help improve performance in certain soils, for example water jets for burying in sand.

Plate 5-10: Example of a non-displacement plough (Source: Equinor)

155. A non-displacement plough was used with very good results for the installation and burial of the nearby Dudgeon export cables. In environmental terms, the year 1 post-construction monitoring report for Dudgeon (MMT, 2019) has demonstrated very little temporary impact to the seabed along the export cable route. This experience has been taken into account, alongside the outcomes of the DEP and SEP draft cable burial risk assessment (Pace Geotechnics, 2020). As a result, should a plough be selected as the appropriate burial tool for DEP and SEP, a non-displacement type will be used to minimise environmental impact.

156. The rate of burial using a plough depends on factors including bathymetry, ground conditions and the required towing tension. An indicative burial rate by ploughing is 150-300m/h.

157. There may be locations where other methods to bury and protect the cable are required even where ploughing is used as the primary burial tool e.g. for any jointing loops, corner areas and where ploughing would be unable to negotiate obstacles or cable crossings.

5.4.7.5.2 Jetting

158. Jetting uses high powered jets of water to fluidise the seabed sediments and lower the cable to the required depth. Jetting may be undertaken either as a separate operation on a cable that has been pre-laid on the seabed, or by simultaneously laying and jetting. As with a plough, the jetting tool can either be pulled directly by a surface vessel or mounted onto self-propelled caterpillar tracked vehicles.

159. Indicative dimensions of a large jetting tool are 5m x 4.2m x 3m. An indicative burial rate by jetting is 150-450m/h.

5.4.7.5.3 Mechanical cutting

160. This method involves the excavation of a trench (either by pre-trenching or simultaneously with cable laying), with the excavated material placed alongside. The cable is then laid in the trench and the sediment returned to the trench to complete the burial of the cable, either mechanically or by natural processes. This is a challenging and time consuming process (indicative burial rate is 30-80m/h) and while it will not be used as the primary burial method, may be required for particular sections where the other methods are not feasible.

5.4.7.5.4 Trench sizes

161. The maximum temporary disturbance width for export, interlink and infield cable installation would be up to 3m, encompassing the pre-grapnel run and trenching works. The footprints for pre-sweeping (where required) would be additional to this, as described in **Section 5.4.7.4.1.3**.

5.4.7.6 Infield Cable Installation

162. Since it is not possible to bury the infield cables in close proximity to the wind turbines and OSP/s due to the scour protection that will be installed, the cables would be surface laid with cable protection on the approach to each foundation. An allowance of up to 1,000m of cable protection (total across both DEP and SEP) is included for this purpose, although it would be entirely within the footprint of the foundation scour protection.

163. Each section of cable will be laid from the cable lay vessel either from a static coil or a revolving carousel, turntable or drum. The cable will be pulled into the turbine foundation via a J-tube (or alternative cable entry system) and hung-off inside the foundation structure before being connected to the turbine electrical system. A typical methodology for installing the cable into a J-tube is:

- Mobilisation of a specialist cable installation vessel to site.
- A DP operated vessel will take up station adjacent to a wind turbine foundation. The cable end will be connected to a pre-installed messenger wire at the wind turbine foundation. The messenger wire will be recovered by a Remotely Operated Vehicle (ROV). The messenger wire would then allow the cable to be pulled into the wind turbine foundation from a temporary pre-installed winch arrangement at the wind turbine foundation. An ROV will be used to monitor the cable entering the J-tube or cable entry system.
- When the first cable end is pulled in with required overlength, the cable is secured with a temporary hang-off arrangement and cable installation continue towards the wind turbine foundation for second end pull-in and hang-off. Separate teams will be mobilized for installing permanent hang-off of the cable and terminate the cable cores and fibre optic cables.

- Second end cable pull-in, hang-off and termination will in principal be similar to the first end, except for overboarding of the last end of the cable from the installation vessel that will be by means of a quadrant.
- The same principle for cable installation is applicable for wind turbine foundations without a J-tube. The main differences are the interface between the cable protection system and the foundation entry; without a J-tube the cable is free hanging inside the foundation structure.

5.4.7.7 External Cable Protection

5.4.7.7.1 Need for external cable protection

164. There are certain situations where the use of external cable protection may be required. These are:
   - Where an adequate degree of protection has not been achieved from the burial process. This may be as a result of challenging grounds conditions, or unforeseen circumstances with the burial process, such as break down of the burial tool/s.
   - Where the infield cables approach the wind turbines and OSP/s, as described above in **Section 5.4.7.6** (N.B the corresponding footprint is within the allowance described for scour protection and therefore is not included in **Table 5-21**: below).
   - At cable crossings (**Section 5.4.7.7.4**).
   - At the HDD exit pit (**Section 5.4.7.7.5**).
   - In the event that cables become unburied as a result of seabed mobility during the operation of the wind farms or (where necessary) in the event of making a cable repair (discussed in **Section 5.4.10.3**). If these works were required they would be the subject of a separate marine licence application and therefore are not included in the project design envelope.

165. In all cases, the amount of external cable protection will be minimised as far as is possible. It should be noted that none has been used on either of the existing Sheringham Shoal and the Dudgeon OWF export cable routes, with the exception of the HDD exit location at Dudgeon. At Sheringham Shoal, where satisfactory burial depth of the export cables was not achieved in the first instance, remedial work was performed by additional passes of the trenching tools. Ploughing performed on the Dudgeon export cables was considered to be satisfactory without any remedial work. The seabed footprints of external cable protection requirements for DEP and SEP are summarised in **Section 5.4.1.1** and **Table 5-21**:.

5.4.7.7.2 Types of external cable protection

166. A range of external cable protection systems are available and include:

- Rock placement – the laying of loose rock on top of the cable. Use of rock is often preferred as it is well proven to offer excellent protection in the marine environment, is suitable for application over large areas and is relatively simple and cost effective to deploy.
- Concrete mattresses – prefabricated flexible concrete coverings laid on top of the cable. Deployment is slow and therefore mattresses only tend to be used for short sections of cable.
- Frond mattresses – similar to concrete mattresses but the addition of fronds is used to encourage the settlement of sediment over the mattress and the cable underneath. Only suitable in certain hydrodynamic and sedimentary conditions.
- Protective aprons or coverings – solid structures of varying shapes, typically prefabricated in concrete or similar;
- Bagged solutions – including geotextile sand containers, rock-filled gabion bags or nets, and grout bags, filled with material sourced from the site or elsewhere).
- Uraduct shell or similar – a protective shell fixed around the cable. Generally used for short spans at crossings or near offshore structures where there is a high risk from falling objects. Uraduct does not provide protection from damage due to fishing trawls or anchor drags.

167. Protection systems may be placed alone or in combination with other types and may be secured to the seabed where necessary.

168. Where appropriate, cable clips (also known as cable anchors or anchor clamps) may also be utilised to secure cables to the seabed.

5.4.7.7.3 Unburied cables

169. An allowance is made for external cable protection where an adequate degree of protection has not been achieved from the burial process. The cable protection is assumed to have a width on the seabed of up to 6m for the export and interlink cables and 4m for the infield cables. A total allowance of up to 500m is assumed for the export cables, 1,500m for the interlink cables (1,000m for DEP North and 500m for DEP South) and 1,000m for the infield cables.

5.4.7.7.3.1 External cable protection requirements in the Cromer Shoal Chalk Beds MCZ

170. The use of external cable protection creates a footprint on the seabed for the lifetime of the Projects, dependent on the subsequent need and/or ability to remove the cable protection on decommissioning (see below). As above, the amount of external cable protection will be minimised as far as is possible across the whole project area. Given the sensitivity of the MCZ, the allowance for external protection within the MCZ boundaries has been further restricted by the Applicant as follows (**Table 5-21**:):

- For unburied cables, no more than 100m of external cable protection per export cable, up to 6m in width (i.e. up to 200m within the total allowance of 500m for the export cables).

- At the HDD exit pit transition zone, no more than 100m of external cable protection per export cable, up to 3m in width (i.e. up to 200m in total for two cables).
- No use of loose rock type systems.

171. All external cable protection used within the MCZ will be designed to be removable on decommissioning, although the requirement for removal will be agreed with stakeholders and regulators at the time. Details describing the feasibility of, and commitment to, removing external cable protection will be provided alongside the DCO application as a part of the outline CSIMP and will take account of a Natural England study on the decommissioning of cable protection, which is expected to be published in the first half of 2021.

5.4.7.7.4 Cable crossings

172. Potential crossings include (see **Chapter 18 Petroleum Industry and Other Marine Users** for details):
    - The Lancelot to Bacton gas export pipeline (PL876) (together with the Bacton to Lancelot chemical pipeline (PL877)); and the Shearwater to Bacton gas pipeline (PL1570), all of which run parallel to each other and traverse the DEP South wind farm site.
    - The Durango to Waveney gas production pipeline traversing the DEP North wind farm site.
    - Export cables for the existing Dudgeon OWF which also make landfall at Weybourne. The proposed DEP and SEP offshore export cables cross and then route to landfall to the east of these cables.
    - The Dudgeon OWF export cables will also be crossed further offshore by interlink cables, either those connecting DEP South to an OSP in the SEP wind farm site (in a DEP and SEP together scenario), or interlink cables from DEP South to DEP North.
    - The offshore export cable corridor for the consented Hornsea Three OWF crosses the DEP and SEP offshore export cable corridor approximately 14km from the coast, making landfall at Weybourne to the west of the DEP and SEP landfall. As such, in the event that Hornsea Three is constructed, the DEP and SEP offshore export cables would also need to cross the Hornsea Three offshore export cables.

173. The maximum width and length of cable protection for crossings is 21m and 100m, respectively. The maximum height of cable crossings will be 1.7m and all crossings will be designed to be overtrawlable. The seabed footprint of cable crossings is summarised in **Section 5.4.1.1** and **Table 5-21**:.

174. Crossings are designed to protect the obstacle being crossed, as well as the DEP and SEP cables once they have been installed. Detailed methodologies for the crossing of cables and pipelines will be determined in consultation with the owners of the infrastructure to be crossed. However, a number of techniques may be utilised, including:

- Pre-lay and post lay concrete mattresses;
- Pre-lay and post lay rock placement; or
- Pre-lay cable with Uraduct shell structure protection and post-lay rock placement / rock bags.

5.4.7.7.5 HDD exit pits cable protection

175. Where the offshore export cables exit onto the seabed from the HDD at the landfall, 100m of cable protection may be placed in the transition zone along each of the cables, from the HDD duct sections on the seabed to the start position for cable burial. Rock bags are considered to be suitable for this purpose and, as explained above, loose rock will not be used in this location as it is within the Cromer Shoal Chalk Beds MCZ. The design of the cable protection in this location will also take account of the need to restrict any reduction in water depth to less than 5% on account of navigational risks. Further details are provided in **Section 5.5**.

5.4.7.7.6 Summary of potential cable protection requirements

176. A summary of all potential cable protection requirements is provided in **Table 5-21**:.

Table 5-21: Cable protection summary

Cables	Maximum number of crossings	Crossing protection (m^2)	Protection of unburied cable (m^2)	Protection of unburied cable notes	Total (m^2)
Export	8 (up to 2 DEP & SEP cables crossing 2 export cables for each of Dudgeon and Hornsea Project Three OWFs)	16,800	3,000	Based on 500m protection in total of the export cables, 6m wide, which includes up to 200m in the MCZ	19,800
Export (HDD exit)	n/a	n/a	600	Based on 100m protection of each of the export cables, 3m wide	600
Interlink	6 (up to 3 interlink cables from DEP South crossing 2 Dudgeon OWF export cables)	12,600	9,000	Based on 1,500m protection, 6m wide	21,600

Cables	Maximum number of crossings	Crossing protection (m²)	Protection of unburied cable (m²)	Protection of unburied cable notes	Total (m²)
Infield	7 (Durango to Waveney pipeline (3); Lancelot to Bacton pipeline (2); and Shearwater to Bacton pipeline (2))	14,700	4,000	Based on 1,000m protection, 4m wide	18,700
Total	**-**	**44,100**	**16,600**	**-**	**60,700**

5.4.8 Construction Vessels

177. A variety of vessels will be used during the construction phase, although the exact number and specification will not be known until much closer to the time of construction. Similarly, whilst it is expected that both DEP and SEP will be operated from the O&M port at Great Yarmouth, as with the existing Dudgeon OWF, the construction port/s will not be confirmed until nearer the start of construction.

178. In order to inform the environmental assessment, **Table 5-22**: below gives an indication of the maximum construction vessel quantities and related movements to and from port that can be expected on site at any one time. Due to construction sequencing not all types of vessel will be on site at the same time.

179. A total of 1,196 vessel movements is estimated during construction of both DEP and SEP on a worst case basis (assuming the Projects are constructed sequentially).

Table 5-22: Construction vessels

Vessel type	Indicative maximum number on site at any one time (one project – DEP or SEP)	Indicative maximum number on site at any one time (DEP & SEP)	Indicative maximum number of vessel movements[4] (one project – DEP or SEP)	Indicative maximum number of vessel movements (DEP & SEP)
Rock bulk vessel	2	2	4	8
Filter layer vessel	1	2	4	8
Foundation installation spread	1	2	25	50

[4] Transit to and from port equates to two movements.

Vessel type	**Indicative maximum number on site at any one time (one project – DEP or SEP)**	**Indicative maximum number on site at any one time (DEP & SEP)**	**Indicative maximum number of vessel movements[4] (one project – DEP or SEP)**	**Indicative maximum number of vessel movements (DEP & SEP)**
Transition piece Installation	1	1	25	50
Scour vessel	1	2	4	8
WTG installation spread	1	2	25	50
Commissioning vessels	1	2	90	180
Accommodation vessels	1	1	4	6
Infield cable vessels	1	2	8	16
HDD construction vessels (landfall construction) – two vessels for excavation and backfilling	2	2	8	16
Export cable vessels	1	2	2	4
OSP installation vessels	1	1	4	8
Other vessels – three to four vessels operational on a daily basis during construction and commissioning	2	4	400	800
Total	**n/a**	**n/a**	**603**	**1,196**

180. Where they are used, jack-up barges and anchored vessels will have a seabed footprint (**Table 5-23**:) (these footprints are also incorporated in **Section 5.4.1.1**). For this purpose it is assumed that there would be one operation for each foundation installation (most likely using anchors) and a further operation for each wind turbine installation (most likely using a jack-up). Jack-up vessels may have up to four legs/spudcans, each with a footprint of up to $300m^2$. In the case of anchoring, it is likely to be a wire line system with drag/fluke anchors, with up to 12 lines per location. The footprint of each anchor would be up to 6m in width (approximately $30m^2$), with an anchor line length of up to 1,000m. There would usually be one anchor pattern per foundation, although re-setting of anchors is sometimes required in the event that they do not hold position (two assumed as a worst case).

Table 5-23: Construction vessel footprints (foundation, wind turbine and OSP installation)

Parameter	Jack-up	Anchors
Number of legs/anchors	4	12
Footprint area per placement (m^2)	1,200	360
Max. number of operations per foundation installation	n/a	2
Max. number of operations per wind turbine installation	2	n/a
Number of wind turbine and OSP locations	56 +2 OSPs	56 +2 OSPs
Total footprint (m^2)	**139,200**	**41,760**

181. Anchoring may also be used by the interlink and export cable installation vessel where a simultaneous lay and plough methodology is used. Assuming a typical anchor spread with up to seven mooring lines and an anchor footprint of up to $30m^2$, and repositioning of the mooring lines every 500m, the maximum footprint for anchoring during cable installation would be up to $64,680m^2$ and $42,840m^2$ for the interlink and export cable routes respectively, although this will vary according to the development scenario in question (**Table 5-24** and **Table 5-25**:).

Table 5-24 Anchoring footprint for interlink cable installation

Development scenario	Interlink cable length (all cables) (km)	Anchoring footprint (m^2)
Integrated grid option: DEP & SEP together – 1 OSP at SEP (assuming both DEP North and DEP South are developed)	143	60,060
Integrated grid option:	154	64,680

Development scenario	Interlink cable length (all cables) (km)	Anchoring footprint (m^2)
DEP & SEP together – 1 OSP at SEP (assuming only DEP North is developed)		
Separated grid option: DEP & SEP together – 1 OSP at SEP and 1 OSP at DEP North (assuming both DEP North and DEP South are developed)	66	27,720
DEP in isolation (assuming both DEP North and DEP South are developed)	66	27,720

Table 5-25: Anchoring footprint for export cable installation

Development scenario	Export cable length (km)	Anchoring footprint (m^2)
DEP in isolation	62	26,040
SEP in isolation	40	16,800
DEP & SEP together – 1 OSP at SEP	80	33,600
DEP & SEP together – 1 OSP at SEP and 1 OSP at DEP North	102	42,840

5.4.9 Safety Zones

182. Safety zones may be used to help ensure safe working during all phases of the development, namely to ensure a safe distance is maintained between the wind farm structures and vessels. The implementation of all safety zones will be subject to application and approval prior to the start of construction. The safety zones that may be applied for are summarised in **Table 5-26**:.

183. Further information on safety zones is provided in **Chapter 14 Shipping and Navigation** and will also be provided in the Safety Zone Statement that will accompany the DCO application.

Table 5-26: Safety zones that may be applied for

Potential safety zone	Details
Construction	Up to 500m around each wind turbine foundation or OSP whilst under construction.

Potential safety zone	Details
Commissioning	Up to 50m around each wind turbine foundation or OSP where construction has finished but where some work may be ongoing e.g. a wind turbine that is incomplete or in the process of being tested before commissioning.
Major Maintenance	Up to 500m when major maintenance is in progress (use of jack-up vessel or similar).
Decommissioning	Up to 500m at the end of the working life of a wind turbine foundation or OSP when it is being decommissioned.

5.4.10 Offshore Operation and Maintenance

184. The ongoing operation of the wind farms over the DEP and SEP design life of 35 years will require a number of operation and maintenance activities. A key characteristic of the operation of DEP and SEP is the intention that both will be operated from the existing Dudgeon OWF O&M base at Great Yarmouth (see **Section 5.4.10.5** for further details). Shared vessels, personnel and facilities offer a considerable benefit in optimising (and ultimately reducing) the overall O&M effort required across all three projects. For example, fewer support vessels and fewer overall vessel movements would be required as opposed to a scenario where all projects were operated entirely independently. If it is not possible to use Great Yarmouth, a suitable alternative location for the O&M base will be selected.

185. An outline Operations and Maintenance Plan will also be provided with the DCO application and will provide further details of the anticipated activities and how they will be controlled by the DCO.

5.4.10.1 General Maintenance Activities

186. A programme of monitoring and scheduled maintenance will be undertaken through the lifetime of the wind farms to ensure that all offshore infrastructure is maintained in safe working order and to maximise operational efficiency.

187. Operational control of the wind farms will be through a Supervisory Control and Data Acquisition (SCADA) system, which will connect each turbine to the onshore control room. This system will enable the remote control of individual turbines, as well as remote interrogation, information transfer and data storage.

188. Surveys including geophysical survey (most typically multibeam echosounder and/or side scan sonar) and through the use remotely operated vehicles will be performed at regular intervals throughout the operational lifetime of the wind farms. A typical geophysical survey programme for asset integrity purposes would involve survey of foundations and subsea cables at least every two years, although the work programme will be adapted to focus on areas of greatest interest, for example in areas of greatest seabed mobility.

189. Typical general maintenance activities include:

- Wind turbine service;
- Oil sampling and/or change;

- UPS (uninterruptible power supply) battery change;
- Service and inspections of wind turbine safety equipment, nacelle crane, service lift, high voltage system, blades;
- Foundation inspection and repair;
- Cable repair and replacement;
- Cable remedial reburial;
- Cable crossing inspection and repair; and
- Unplanned and planned corrective work.

190. Subsea cables are designed for the lifetime of the Projects, however reactive repairs or remedial cable reburial work may be required, which are addressed in **Sections 5.4.10.3** and **5.4.10.4** below.

191. Large components (e.g. wind turbine blades or OSP transformers) are not expected to need replacement frequently during the operational phase, although failure of these components is possible. In this event, a jack-up vessel may be required to operate continuously for significant periods to carry out major maintenance activities of this type. For this purpose, it is assumed that there could be up to 10 jack-up movements per year for each of DEP and SEP (i.e. 20 in total). Assuming a jack-up vessel with a seabed footprint of 1,200m^2 (up to four legs/spudcans, each with a footprint of up to 300m^2), this would lead to a total footprint of up to 24,000m^2 per year.

5.4.10.2 Vessel Operations

192. Vessel visits to the wind farms will be required each year to allow for scheduled and unscheduled maintenance activities. As discussed above, both DEP and SEP will be operated from the existing Dudgeon OWF O&M base at Great Yarmouth, sharing vessels and facilities. The existing Dudgeon OWF vessel provision consists of one service operation vessel (SOV) and one smaller crew transfer vessel (CTV). Taking account of the existing spare capacity in terms of onboard facilities and capability for technician drop-offs, it is anticipated that a maximum number of one to two extra support vessels would be sufficient. These could be CTV, daughter craft onboard the SOV or both. **Table 5-27**: provides a breakdown of the maximum number of vessels that may be required at any one time and the anticipated maximum number of vessel movements per year during operation.

Table 5-27: Maximum anticipated trips to the wind farms during operation

Vessel type	Indicative maximum number of vessels required at any one time (one project – DEP or SEP)	Indicative maximum number of vessels required at any one time (both projects – DEP & SEP)	Indicative maximum number of vessel movements (one project – DEP or SEP)	Indicative maximum number of vessel movements (both projects – DEP & SEP)
Large O&M	1	1	60/year	60/year

Vessel type	Indicative maximum number of vessels required at any one time (one project – DEP or SEP)	Indicative maximum number of vessels required at any one time (both projects – DEP & SEP)	Indicative maximum number of vessel movements (one project – DEP or SEP)	Indicative maximum number of vessel movements (both projects – DEP & SEP)
vessel (SOV)				
Small O&M vessel (CTV)	2	2	624/year	624/year
Lift vessel	2	4	4/year	8/year
Cable repair vessel	1	1	2/10 years	4/10 years
Survey vessel	1	1	2/year	2/year

5.4.10.3 Cable Repair or Replacement

193. Based on current knowledge and technology the estimated rate of cable failure for DEP and SEP is approximately one failure for every 1,000km of cable per year. On this basis, the assessment considers the following potential cable repair works across DEP and SEP (including replacement where necessary):
    - One export cable repair every 10 years (including one in the Cromer Shoal Chalk Beds MCZ);
    - One interlink cable repair every 10 years; and
    - Two infield cable repairs every 10 years (N.B. for short infield cables, replacements are a more likely operation).
194. The basic methodology for carrying out a cable repair will involve removal of the damaged or faulty section of the cable, cutting of that section (unless replacing the whole cable), followed by the insertion of a new cable section to be joined to the existing cable. The seabed footprint of cable repair and replacement works is summarised in **Table 5-28** below.
195. The section of cable to be repaired will be exposed using techniques such as jetting or mass flow excavation (if buried) and/or removal of any external cable protection. Once the repair is completed, jetting or other suitable methods of trenching would be used to rebury the cable and/or the external cable protection reinstated.

196. For infield cables, the entire length of a cable (likely to be between 0.2km and 5km subject to turbine spacing) could require replacement and therefore 5km has been assumed as the worst case. For the longer interlink and export cables, an extended cable loop (‘bight’) of up to 250m (depending on the water depth) would be surface laid onto the seabed close to and to one side of the original cable, prior to the cable being protected as described above. The 250m may represent the maximum distance of the bight from the original cable route. As the cable has to be cut up to 200m of the cable ends pulled out of a trench, there will be up to 800m of reburial of the cables after omega repair. For these operations it is assumed that a dynamically positioned vessel will be used.

197. In the event that external cable protection is required, up to a total of 700m of cable would need to be protected for each cable repair, allowing for a new cable of 300m to be inserted after a cut with the corresponding two repair joints. As up to 200m of laid cable must be taken out of the trench in two directions after the cable cut, the total cable length that may be subject to external cable protection after an omega repair (per cable) is 800m, with a berm width of up to 4m. However as described in **Section 5.4.7.7.1**, if this were required during operation it would be the subject of a separate marine licence application and therefore is not included in the project design envelope.

5.4.10.4 Cable Reburial

198. In the event that cables become exposed due to the natural movement of the seabed over the lifetime of the Projects, it may be necessary to undertake remedial reburial work to ensure that the cables are adequately protected and without the need to resort to the use of external cable protection measures such as rock placement (described in **Section 5.4.7.7**). The need for reburial work will be informed by an ongoing programme of geophysical surveys (as described in **Section 5.4.10.1**) as well as the cable burial risk assessment. A draft export cable burial risk assessment has been completed (Pace Geotechnics, 2020) and will be updated prior to the start of construction.

199. The following reburial requirements have been estimated based on the worst case scenario that no pre-sweeping is undertaken and all cables are buried under the seabed level as described in **Section 5.4.7.5**. If undertaken, pre-sweeping would minimise the likelihood of reburial works being required in areas of sand waves and/or high seabed mobility.

- Estimated export cable reburial at 10 year intervals:
  - Up to 0.1km per cable within the Cromer Shoal Chalk Beds MCZ; and
  - Up to 0.1km per cable outside the MCZ.
- Reburial of 1% of the infield cabling is estimated every 10 years.
- Reburial of 1% of the interlink cabling is estimated every 10 years.

200. The seabed footprint of cable reburial works is summarised in **Table 5-28** below.

201. An In Principle Monitoring Plan will be submitted with the DCO application which will outline the proposed monitoring, the details of which would be agreed post consent with the relevant Regulators and SNCBs. Post-construction surveys are likely to be a requirement of the DCO/DMLs.

5.4.10.5 Cable Repair, Replacement and Reburial Seabed Footprint Summary

202. **Table 5-28** summarises the seabed footprints in relation to cable repair, replacement and reburial works. The footprints and based on a maximum temporary disturbance width of 3m. Overall totals are not provided as the impacts would occur at different times over the 35 year lifetime of the wind farms.

Table 5-28: Cable Repair (and/or replacement) and Reburial Seabed Footprints

Activity	Details	Footprint (m^2)
Export cable repair	One export cable repair every 10 years (DEP and SEP) Up to 800m, 3m disturbance width	2,400m^2 / 10 years
Interlink cable repair	One interlink cable repair every 10 years Up to 800m, 3m disturbance width	2,400m^2 / 10 years
Infield cable repair	Two infield cable repairs every 10 years (DEP and SEP) Up to 5km each, 3m disturbance width	30,000m^2 / 10 years
Export cable reburial	Up to 200m per export cable subject to reburial works every 10 years Assumes up to two export cables, 3m disturbance width	1,200m^2 / 10 years
Interlink cable reburial	Reburial of 1% of up to 154km of interlink cabling every 10 years (1.54km). 3m disturbance width	4,620m^2 / 10 years
Infield cable reburial	Reburial of 1% of 225km of infield cabling every 10 years (2.25km) (DEP and SEP) 3m disturbance width	6,750m^2 / 10 years

5.4.10.6 O&M Port

203. As described above, the intention is that both DEP and SEP will be operated from the existing Dudgeon OWF O&M base at Great Yarmouth. O&M needs in terms of laydown areas and facilities are expected to be minimal compared to requirements during the construction phase and will be sufficiently provided for through the existing base.

204. The base includes a purpose designed building and control room on the river harbour quayside, opened in July 2016, from where all operational and maintenance activities are planned and co-ordinated (**Plate 5-11**). The base is currently home to approximately 70 permanent employees including engineers, control room operatives, marine co-ordinators, planners and support staff. The building also includes a large warehouse facility for storing spare parts and for receiving goods and equipment associated with the support of the vessels used to access the wind farm.

205. Turbine technicians board the vessels from the base to make the journey to the wind farm site/s. A marine coordination team monitors the movement of vessels and personnel offshore, and is in constant communication with the vessels in the field. All maintenance and repair work on the wind farm network is controlled through the Work Release System, and the issue of Safety Documents acts as the official sanction for work to be undertaken. The Work Release System is operated by the control room engineers, who are responsible for responding to faults on the electrical network so that maximum generation can be restored as soon as is practically possible. It is expected that DEP and SEP will be integrated with this same system.

Plate 5-11: Existing Dudgeon O&M base at Great Yarmouth (Source: Equinor)

5.4.11 Repowering

206. Once any potential life extension opportunities have been exhausted (through those maintenance activities described above and as provided for within the DCO), repowering may be considered at or near the end of the 35 year design life of the wind farms. Repowering could involve the replacement of turbines and/or foundations with those of a different specification or design, for example to enable the installation of more efficient wind turbines.

207. In this event, if the specifications and designs of the new turbines and/or foundations were outside the existing maximum design scenario, or the impacts of constructing, operating and decommissioning them were to fall outside those considered in this EIA, repowering would require further consent (and EIA) and is therefore outside of the scope of this document. At this time, it is not expected that repowering would require removal of existing or installation of new offshore (or onshore) cables.

5.4.12 Offshore Decommissioning

208. At the end of the operational life of the wind farms, DEP and SEP will be decommissioned, in line with TCE AfL requirements. Under the Energy Act (2004), a decommissioning plan must be submitted to and approved by the Secretary of State for Business, Energy and Industrial Strategy, a draft of which will be submitted prior to the start of construction. It is expected that the decommissioning plan and associated programme will subsequently be updated during the lifetime of DEP and SEP to reflect any changes to regulatory requirements, best practice and new technologies.

209. As such, the scope of the decommissioning works would be determined by the relevant legislation and guidance at the time. It is anticipated that all structures above the seabed or ground level will be completely removed, including all of the wind turbine components and the parts of the foundations above seabed level. Removal of some or all of the infield, interlink and export cables may be undertaken, although scour and cable protection would likely be left in-situ other than where there is a specific condition for its removal.

210. The decommissioning sequence will generally be the reverse of construction and will involve similar types and numbers of vessels and equipment. The anticipated techniques for the various foundation types are as described below.

211. It is anticipated that offshore decommissioning would take up to approximately one year for each of DEP and SEP.

5.4.12.1 Foundations

212. Piled foundations (jackets and monopiles) would be cut approximately 1-2m below seabed level following localised jetting or suction around the base of the pile to clear surface sediments and/or scour protection and provide access to the cutting tools. Complete removal of piles from the seabed is not considered to be reasonably practicable at this time, as there is currently no proven, cost-effective technology for their removal. The size of the piles, the penetration depth into the seabed and the weight make it technically extremely challenging to remove the entire structure, involving safety risks to personnel and significant disturbance to the seabed due to the excavation work that would be required.

213. Gravity base foundations would be decommissioned by removal of their ballast and either floating them (for self-floating/buoyant designs) or lifting them off the seabed. This process may need to be preceded by the clearance of seabed sediments and/or scour protection and grout from the base of the foundation by jetting and/or suction. If a deep skirt has been used around the perimeter of the foundation, the skirt may require cutting. For the removal of ballast, careful consideration would need to be given to the disposal or re-use of the ballast material.

214. Suction buckets would include similar steps to clear seabed sediments and/or scour protection from around the base of the foundation. Depending on the precise design, decommissioning may include: removal of ballast or the adding of buoyancy aids; connection of pumping equipment to the suction bucket valves; and controlled pumping of water into caisson chambers. The suction bucket would then be expected to rise to the surface as the internal pressure overcomes the side wall friction. Some manipulation from craneage on a suitable vessel may be required as part of this process.

215. For all foundation types, a heavy lift DP vessel or jack-up crane would then be used to lift the foundation onto a barge for transport to shore.

5.4.12.2 Cables

216. There is no existing statutory requirement for removal of decommissioned cables. Furthermore, removal of buried cables is technically difficult and in cases it is possible that if attempted, the removal works would cause significantly greater environmental disturbance than leaving them in situ. Techniques are likely to be similar to those considered for the installation, in a reverse process to expose and remove them. Once the cables are exposed, grapples would likely be used to pull the cables onto the decks of cable removal vessels. The cables would then be cut into manageable lengths and returned to shore for recycling.

217. Cables that are not buried i.e. are exposed are more likely to be removed to ensure they do not become hazards to other activities such as shipping and fishing. Detailed survey and engineering studies will be required at the time of decommissioning in order to determine which cables are exposed (or are at risk of future exposure), and therefore the most appropriate course of action.

218. With this in mind it is expected that most infield, interlink and export cables will be cut at the ends and left in situ. However, for the purpose of this DCO application, it has been assumed as a worst case that all cables will be removed during decommissioning, though any cable protection installed will be left in situ. The area of seabed impacted during the removal of the cables could therefore be equal to the area impacted during the installation of the cables.

219. At the landfall the export cables will have been installed in ducts by the HDD process. To minimise environmental disturbance the preferred option is to leave these cables buried in place with the cable ends cut, sealed and securely buried.

5.5 Landfall

5.5.1 Background

220. The offshore export cables make landfall at Weybourne, at a preferred location to the west of Weybourne beach car park at the Muckleburgh Military Collection. The offshore export cables will be connected to the onshore export cables in a transition joint bay, having been installed under the intertidal zone by HDD (**Figure 5.4**). This technique has been selected by the Applicant in order to avoid any impact to the MCZ in this area. Chalk is known to outcrop on the seabed close to shore, where it forms one of the key interest features of the site (see **Chapter 8 Marine Geology, Oceanography and Physical Processes** and **Chapter 10 Benthic and Intertidal Ecology** for further details). As described below, the HDD process will allow the complete avoidance of the nearshore outcropping chalk feature.

221. There is a high degree of confidence in the feasibility of HDD at this location given the Applicant's previous installation campaigns for both Sheringham Shoal and Dudgeon OWFs, which also used HDD to successfully install two export cables per project. As a result, whilst other cable installation projects have needed to consider other construction methodologies at the landfall, for example involving open cut trenching and the creation of cofferdam structures on the beach, these alternative options have been discounted at an early stage for DEP & SEP.

222. The onshore landfall area of the PEIR boundary comprises a 1,500m stretch of coastline, however only a relatively small area within this would be required for the HDD compound (approximately 5,750m^2). The wider landfall area identified, which includes the beach frontage but avoids the cliff line further to the east (refer to **Figures 5.4** and **5.9**), also provides space adjacent to the beach for onshore duct preparation. The landfall area also extends inland to allow the transition joint bays to be located beyond any areas at risk of natural coastal erosion, and to provide space for temporary construction logistics and access requirements.

223. The landfall area at Weybourne was chosen as the result of a site selection process, considering environmental and technical constraints. The site selection process is described in **Chapter 4 Site Selection and Assessment of Alternatives**.

224. One HDD duct will be required for the installation of each of the DEP and SEP export cables. As such, up to two drills will be undertaken for the landfall works. An extra drill per project has been allowed for contingency (i.e. up to four drills in total to install two ducts). Each drill will be launched from a compound inland, drilled under the beach and intertidal area, and will exit out at sea.

5.5.2 Landfall Works

225. A temporary onshore compound will be required to accommodate the drilling rigs, ducting and welfare facilities. The temporary landfall compound will be set back between 100m to 150m inland from the beach and would be up to 75m long by 75m wide. Each drill would start from the landfall compound, travel beneath the beach, and will exit in the subtidal zone at a suitable water depth. The drill will be of sufficient depth below the coastal shore platform to have no effect on coastal erosion.

Plate 5-12: Example of an onshore landfall compound (Dudgeon OWF) with drilling rig (left of shot) in operation (Source: Equinor)

226. A pilot hole will be drilled from an onshore entry pit and advanced in stages until the required length is reached and the boring head emerges at the exit point. The drill head would be guided by sensors, potentially tracking a wire placed above ground/seabed. Approximately 600-700m^3 of drilling fluid per bore hole (a combination of water and natural clays such as bentonite) will be used to lubricate the drilling process and cool the drill head. Drilling fluid will be recycled where possible, with fluid pressures monitored throughout the process to minimise the potential for breakout of the drilling fluid. An action plan will be developed and procedures adopted during the drilling activity to respond to any drilling fluid breakout. A small amount of drill fluid (up to 25m^3 total for two HDD ducts) may be discharged into the sea during punchout at the exit point.

227. Once the pilot hole is completed, it would be enlarged through several passes with reamers until the necessary diameter for duct installation is achieved. The HDD will exit in the subtidal, approximately 1,000m from the coastline (up to 1,250m from the onshore entry point). The HDD works should not require any prolonged periods of restrictions or closures to the beach for public access, although it is possible that some work activities will be required to be performed on the beach that may require short periods of restricted access. For example, use of a temporary seawater pipe and pump to supply seawater to the onshore HDD temporary works compound for use with the drilling fluid, as well as the use of vehicles to transport the ducting across the beach. Any areas subject to short-term restricted access would be agreed in advance with the Countryside Access Officer at Norfolk County Council prior to construction.

228. The ducts would typically be floated into position at the offshore exit point via barges. The ducts would then be flooded with water and pulled from the direction of the onshore entry pit into the reamed drill holes. Alternatively the ducts could be welded in sections onshore and pushed from the onshore side. The onshore landfall area of the PEIR boundary includes an extended area adjacent to the beach of approximately 1,500m to allow for onshore duct preparation.

229. Once the ducts have been installed they will be protected with bellmouth structures as shown in **Plate 5-13**. The offshore export cables will then be installed at a suitable time, taking into account weather, tide and the wider offshore works schedule, by positioning the cables at the offshore exit point and pulling through the ducts to the transition pit.

230. At the HDD exit point in the subtidal there is a requirement for a transition zone between where the ducts exit the seabed and the point at which it is possible for the burial tool to start the process of burying the cables. There are two options for the transition zone. The first would involve the excavation of an initial trench up to 20m wide, 30m long and 1m deep (600m^3 excavated material, allowing for up to two cables), with a further transition zone trench of up to 50m in length, 1m wide and up to 1m deep per cable (100m^3 excavated material in total), at the end of which the burial tool would be able to take over the cable burial process. With this option there would be no requirement for external cable protection. This option also provides some flexibility should the Projects be restricted in terms of any potential reduction in navigable water depth (the water depth at this location is expected to be approximately 8.5m, although the exact location and corresponding depth will not be confirmed until prior to the start of construction).

231. Alternatively, rock bags or concrete half shells would be used for cable protection purposes in the transition zone. This is considered to be the best option from an engineering perspective, provided that any restrictions on the reduction of water depth can be met. In this event, external cable protection would be required along up to 100m of each of the cables i.e. a total length of 200m for both cables. The cable protection would likely be in the form of removable 8 tonne rock bags (**Plate 5-14** and

232. **Plate** 5-15), up to 3m wide and 0.8m high (accounting for the cables underneath), although some settling into the seabed after installation would be expected to reduce this over time. The seabed footprint of the installed rock bags would therefore be up to 600m^2, for both cables. Loose rock type systems will not be used in order to facilitate the possibility of removal on decommissioning (see **Section 5.4.7.7**).

Plate 5-13: Example of bellmouth used to protect the duct ends at the HDD exit point (Source: Equinor)

Plate 5-14: Example illustration of rock bags used for cable protection in the transition zone

Plate 5-15: Rock bag installation (Source: Equinor)

233. A jack-up barge vessel with backhoe excavator (**Plate 5-16**) would be used for the excavations and/or installing any necessary external cable protection. All excavated seabed sediments will be temporarily stored alongside the works location and within the export cable corridor (i.e. sidecast), prior to being backfilled after cable installation (a period of approximately nine months). The seabed footprint of the deposited material is estimated to be up to approximately 400m^2. Alternatively the excavated sediment could be stored on a barge.

234. Assuming a jack-up barge vessel with four legs, each with a 4m^2 spudcan, the total seabed footprint for each jacking-up operation would be up to 16m^2. Up to 16 movements may be required (DEP and SEP) which would result in a total seabed footprint during construction of 256m^2.

Plate 5-16: Example of a jack-up barge with backhoe excavator (Source: Equinor)

235. Surface lay of the export cables in the transition zone is not considered a viable option, primarily as it would not provide the necessary level of cable protection in the shallow nearshore environment. However it would also be necessary to secure or 'pin' the cables to the seabed in some manner to prevent their movement in the shallow water depths and the presence of unconsolidated surface sediments in this area would not support this.

236. A typical programme for the export cable installation at the landfall would involve mobilisation, drilling of the two boreholes, preparation of the ducts, towing the ducts to the exit point, duct installation and excavation of the transition zone over a period of approximately five months. Upon completion of the duct installation, the onshore landfall compound would be demobilised, including the removal of drilling rigs and welfare facilities from the site.

237. The cable pull-in would then be undertaken, followed by backfilling at the HDD exit and jointing of the subsea and onshore cables in the onshore transition joint bay over a period of approximately six months. During the cable pull phase of works, the transition joint bay(s) (see **Section 5.5.2.1**) would be re-excavated and exposed allowing cables to be pulled through the pre-installed ducts and jointed. The cables would then be tested, the transition joint bays backfilled and landfall area would then be reinstated.

238. The process outlined here effectively describes the process for both an in isolation scenario (one project) and the concurrent scenario. If projects were built sequentially this process would be repeated for the second project. In the sequential scenario synergies between projects would be explored, for example the second project reusing the landfall compound from the first project. However, should there be a gap between the two construction exercises it is assumed that land would be reinstated after completion of the first project and a new landfall compound would be installed at the start of the second project.

5.5.2.1 Transition joint bays

239. The offshore and onshore cables will be jointed together in one or two underground transition joint bays located onshore within the landfall compound. This would comprise an excavated area of up to 20m x 30m (for the worst case DEP and SEP sequential scenario) with a reinforced concrete floor to allow winching during cable pulling and a stable surface to allow jointing.

240. Following cable pulling and jointing activities, the joints would be buried to a depth of 1.2m using stabilised backfill, pre-excavated material or a concrete box. The remainder of the transition joint bay will be backfilled with the pre-excavated material and returned to the pre-construction condition, so far as is reasonably possible.

5.5.2.2 Landfall parameters

241. **Table 5-29** shows the main construction parameters for the landfall site.

Table 5-29 Landfall construction onshore parameters

Landfall	Worst case parameters		
	DEP/SEP in isolation	**DEP/SEP together – concurrent**	**DEP/SEP together – sequential**
Number of HDD drills	Up to 2	Up to 4	Up to 4
Number of HDD drill rigs in operation at any one time	1		
Number of transition joint bays	1	1	2
Transition joint bay(s) dimensions (length x width)	10m x 15m	15m x 15m	2 x (10m x 15m)
Transition joint bay(s) dimensions depth	Up to 2m		
Landfall compound size	Up to 5,750m^2	Up to 5,750m^2	2 x up to 5,750m^2
Length of HDD	Up to 1,250m		
Approximate distance inland from cliff edge of transition joint bay(s)	100m – 150m		

5.6 Onshore

5.6.1 Onshore Cable Corridor

5.6.1.1 Location

242. The location of the 200m wide onshore cable corridor is presented in **Figure 5.9**. The final onshore cable corridor that will be the subject of the DCO application will be up to 60m wide (for the DEP and SEP together scenarios), increasing to a width of 100m for trenchless crossing zones. The final onshore cable corridor will be refined from the 200m wide corridor shown in Figure 5.9. This will be informed by stakeholder feedback on the information provided in this PEIR, as well as further technical studies and ongoing environmental survey and assessment work.

243. From the landfall at Weybourne, the onshore cable corridor travels south, crossing Sheringham Road (A149), and the North Norfolk Railway line between Holt and Sheringham and continuing south to cross Cromer Road (A148) to the east of High Kelling. South of North Norfolk Railway line the cable corridor widens out to 1,200m in proximity to Weybourne Wood. A number of potential routing options are under consideration through this area and will be refined down to a single preferred option within the DCO application. The options include:

- Beneath Sandy Hill Lane - the cable(s) would be laid through open cut trenching in the carriageway.
- Beneath Sandy Hill Lane - using trenchless crossing techniques.
- Through commercial forestry (Weybourne Wood) – either by open cut trenching along existing forest tracks, or using trenchless crossing techniques.

244. The cable corridor continues south passing the villages of Oulton and Cawston and crossing the River Wensum near Attlebridge and then crossing the A47 between Hockering and Easton. From this point the onshore cable corridor heads south east crossing the A11 at Ketteringham before reaching the two onshore substation site options near the existing Norwich Main substation.

5.6.1.2 Onshore cable corridor parameters

245. **Table 5-30** shows the main construction parameters for the onshore cable corridor.

Table 5-30 Onshore cable corridor construction parameters

Onshore cable corridor	Worst case parameters		
	DEP/SEP in isolation	DEP/SEP together – concurrent	DEP/SEP together – sequential
Onshore cable corridor length	60km	60km	2 x 60km
Number of cables	3 x HVAC + 1 fibre optic	2 x (3 x HVAC + 1 fibre optic)	2 x (3 x HVAC + 1 fibre optic)
Onshore haul road length	60km	60km	2 x 60km
Number of work fronts	5 to 10	5 to 10	2 x (5 to 10)

Onshore cable corridor	Worst case parameters		
	DEP/SEP in isolation	DEP/SEP together – concurrent	DEP/SEP together – sequential
Total number of work compounds	2 main compounds. 8 secondary compounds	2 main compounds. 8 secondary compounds	2 x (2 main compounds. 8 secondary compounds)
Size of main compound(s)	60,000m^2		
Size of secondary compounds	2,500m^2 (one of these secondary compounds may be up to 5,000m^2 to provide a second base for welfare and offices if required)		
Cable corridor width	45m	60m	60m
Cable corridor width at trenchless crossings	Up to 100m		
No. trenches	1	2	2
Depth of trenches	Up to 2m		
Cable burial depth (minimum depth of soil to the top of the cable duct)	1.2m		
Width at base of trenches	Up to 1.5m		
Approximate volume of trench excavated material	180,000m^3	360,000m^3	360,000m^3
Approximate volume of trench excavated material to be disposed of	36,000m^3	72,000m^3	72,000m^3
Trenchless crossings compound size	1,500 - 4,500m^2		
Typical jointing bay frequency	Up to every 500m		
Total No. jointing bays	120	120	2 x 120
Jointing bay (length x width x height)	Up to 12 x 4 x 2m		
Depth to top of jointing bay (m)	> 1m		
Link box frequency	Up to every 500m		
Link box (length x width x depth) if below ground	Up to 2m x 2m x 1.5m (plus an above ground marker post at each location)		

Onshore cable corridor	Worst case parameters		
	DEP/SEP in isolation	DEP/SEP together – concurrent	DEP/SEP together – sequential
Link box (length x width x height) if above ground	Up to 1.5m x 1m x 1.5m		
Total No. link boxes	120	120	2 x 120

*The two projects together sequential programme would have up to a one year gap between the completion of onshore works for the first project and the start of the onshore works for the second project. In these circumstances it is assumed that the haul road and construction compounds for the first project would be completely removed and then reinstated at the start of the second project.

5.6.1.3 Onshore export cable installation

246. The onshore cable duct will be installed in sections of up to 1km at a time, with a typical construction presence of up to four weeks along each 1km section.
247. Topsoil would be stripped from the section of the onshore cable corridor to be worked on and stored within the working width. The cable trench(es) would then be excavated, typically utilising tracked excavators. The excavated subsoil would be stored separately from the topsoil, and both will be managed to minimise soil erosion.
248. The cable duct installation works are a continuous activity with each workfront progressing a section at a time. In any given location once the cable ducts have been installed the trench will be backfilled and the workfront will continue moving onto the next section. This would minimise the amount of land being worked on at any one time. However, the haul road will need to be retained throughout much of the cable corridor to maintain access to each workfront.
249. The installation of the onshore export cable is expected to take up to 24 months in total (for the single project in isolation or two projects together concurrent scenarios); or two separate periods of 24 months for the two projects together sequential scenario). Construction may be carried out by up to ten teams (one per 1km section) along the export cable corridor at the same time. Each team typically working on a 400m length of the corridor on any given day, and within that length the extent of open trenches would typically be between 50-100m on any given day, with the trench being excavated at one end and backfilled at the other as works progress along that section.
250. The onshore cable corridor will contain the HVAC onshore export cables and associated fibre optic cables buried underground within ducts for both DEP and SEP. The onshore export cables will require trenches to be excavated, within which ducts will be installed to house the cable circuits or alternatively the cables may be directly laid in the trenches (i.e. a non-ducted system).

251. The onshore cable corridor width of 45m (single project) or 60m (two projects) would also include a haul road to deliver equipment to the installation site from construction compounds, storage areas for topsoil and subsoil and drainage. The working easement is expected to be narrower (approximately 32m for a single project and approximately 48m for two projects) than the width of the Order limits, and this will allow room for micrositing during detailed design, and for onward connection to the existing surface water drainage network for the proposed construction drainage. The typical working widths are presented on **Plate 5-17** - **Plate 5-19** below.

Plate 5-17: Typical working easement for a single project – this allows for micrositing within the 45m Order limits

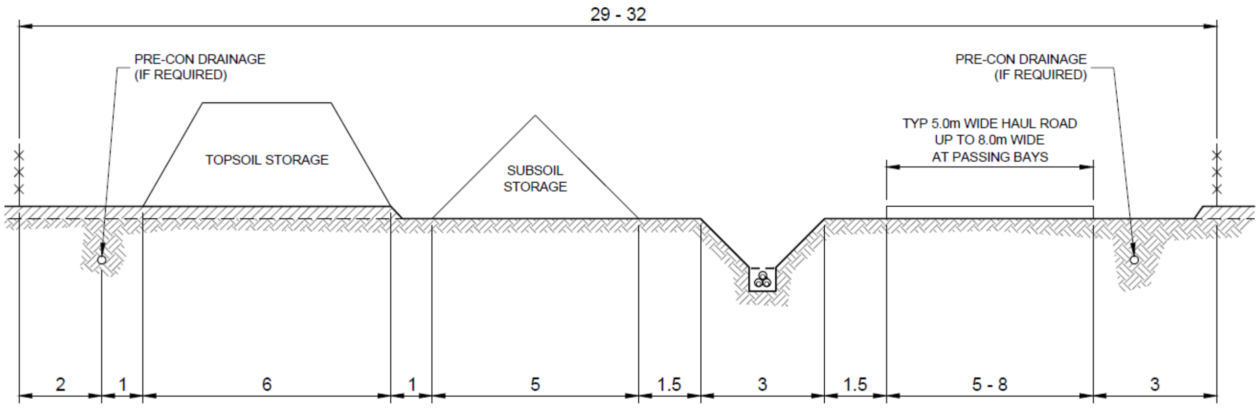


Plate 5-18: Typical working easement for two projects (concurrently) – this allows for micrositing within the 60m Order limits

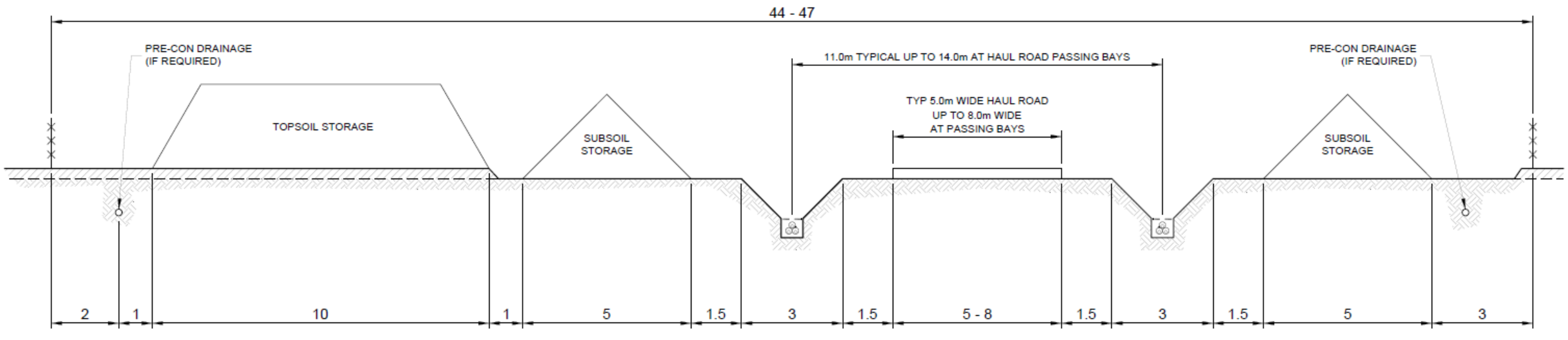
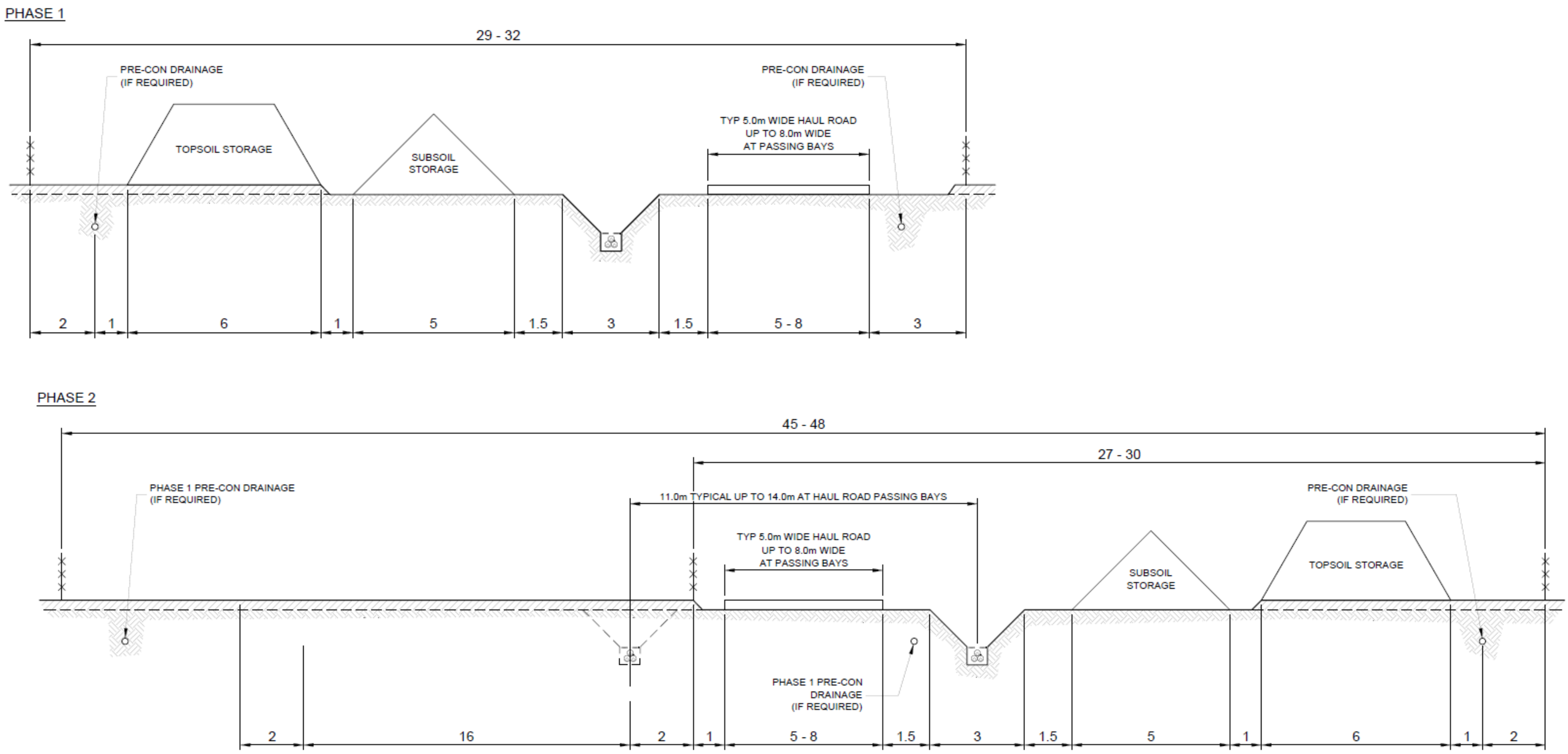


Plate 5-19: Typical working easement for two projects (two phases sequentially) – this allows for micrositing within the 60m Order limits



252. The primary cable installation method will be open cut trenching, with cable ducts installed within the trenches and backfilled with soil. Cables would then be pulled though the pre-laid ducts at a later stage in the construction programme.

253. An approximately 1.2m – 2m deep and up to 1.5m wide trench would be excavated.

254. To minimise impacts of crossing sensitive features such as hedgerows and watercourses, the working width would be reduced to the haul road and cable trenching areas only (approximately 20m).

255. Ducts would be buried to a minimum depth of 1.2m (from top of duct to surface) and installed using two methods:

- Hand laying of ducts, which is suited to short and/or complicated sections; and
- The use of a ducting trailer or trenching machine for longer uninterrupted trenching sections.

5.6.1.3.1 Hand laying method

256. Ducts would be palletised and manoeuvred along the easement using a telehandler (or equivalent). Operatives in the trench would lay zip ties in the base of the trench following the profile of the trench base and sides at predetermined intervals ahead of the ducts being laid (**Plate 5-20**). Ducts are then laid out alongside the trench prior to lifting and lowering into the trench. The ducts would then be jointed together in the trench.

Plate 5-20: Example of hand laying ducts within open trench (Source: Equinor)

5.6.1.3.2 Ducting trailer method

257. For longer sections of ducting a ducting trailer or trenching machine (**Plate 5-21**) may be used. This enables the ducts to be joined on the trailer platform and lowered directly into the trench as the tractor moves the trailer forward. The ducts are zipped tied into the correct formation prior to leaving the working platform. The use of the duct trailer or duct machine minimises the need for personnel to work in the trench.

Plate 5-21: Example of cable trenching machine (Source: Equinor)

5.6.1.3.3 Duct surround and backfill

258. Depending on the thermal resistivity of the soil and the height of the water table, it is likely that a stabilised backfill such as cement bound sand (CBS) will be required to encase the ducting. This is commonly used to ensure that the thermal conductivity of the material around the cables is of a known consistent value for the length of the installation.

259. CBS has a low thermal resistance to conduct the heat produced during electricity transmission away from the high voltage cables. Additionally, as CBS tends to consist of a weak sand to cement ratio (typically 14:1), it is relatively easy to remove if maintenance or removal of cables is required.

260. Once the ducts are encased in CBS (typically a covering depth of 100mm above the ducts) a compaction plate would be used until the required level of compaction is achieved. The trench would then be backfilled in stages using the subsoil stored at the side of the trench and compacted using suitable compaction plant. Following construction the stored topsoil would then be replaced on top of the backfilled subsoil to reinstate the trench to pre-construction condition, so far as reasonably possible (**Plate 5-22**). Due to the introduction of CBS there may be a proportion of the originally excavated soils that would be surplus and may require removal from site. Adoption of a CL:AIRE (Contaminated Land: Applications in Real Environments) Industry Code of Practice will be developed to manage the re-use and disposal of excavated soils on site.

Plate 5-22: Example of backfilled trench following duct installation. End of duct visible in foreground awaiting joint bay construction and cable pulling (Source: Equinor)

5.6.1.3.4 Trenchless crossings

261. Where it has not been possible for the onshore cable corridor to avoid crossing constraints such as major transport routes (road and rail) or large rivers alternative crossing methodologies will be required which are described in **Section 5.6.1.5**.

5.6.1.3.5 Haul road

262. The haul road would provide safe access for construction vehicles along the onshore cable corridor, between construction compounds and the workfronts. This will minimise the amount of vehicles movements between work areas on the existing road network. The haul road would be up to 6m wide (and up to 8m wide at passing bay locations) and as a worst case it is assumed it may be required along the full length of the cable corridor. Speed limits on the haul road are expected to be limited to 20mph.

263. Following an initial topsoil strip, the haul road would be installed in stages as each workfront progresses. It would be formed of protective matting, temporary metalled road or permeable gravel aggregate dependant on the ground conditions, vehicle requirements and any necessary protection for underground services.

264. Where the cable corridor crosses an open ditch or drain, and access for the haul road is required, an appropriately sized culvert may be installed within the ditch and the haul road would be installed over the top of the culvert to maintain access along the cable corridor either side of the ditch. The culvert would be installed in the channel bed so as to avoid upstream impoundment, and would be sized to accommodate reasonable 'worst-case' water volumes and flows. These culverts may remain in place for the duration of the cable duct installation and subsequent cable pull, i.e. up to 24 months total (DEP or SEP in isolation or DEP and SEP concurrent scenarios). For the DEP and SEP sequential scenario the culverts from the first project may be removed following the completion of construction and reinstated at the start of the second project, depending on the gap between the two onshore construction exercises, i.e. in the event that there is a one year gap between the completion of the onshore construction of the first project and the commencement of the onshore construction of the second project it would not be appropriate to leave culverts in watercourses for this extended period of time.

265. At larger crossings, temporary bridges may be employed to allow continuation of the haul road. At sensitive locations such as some rail and river crossings, the haul road would effectively stop and would re-start on the opposite side.

266. When cable duct installation is completed the haul road would be removed and the ground reinstated using the stored topsoil. Some sections of haul road may need to be retained or reinstated to maintain access for the subsequent cable pulling stage (**Section 5.6.1.4**).

5.6.1.3.6 Joint bays

267. Joint bays would be required along the route of the onshore export cables to connect sections of cable. Joint bays would be installed at least 1m below ground and would be of a similar design to the transition joint bay described for the landfall. The joint bays would be formed on completion of the duct installation before the cables are installed and would typically be up to 12m long, 4m wide and 2m high.

268. Joint bays will be constructed with a concrete raft floor, battered sides and a containerised enclosure. Earth mats will be installed within the joint bays and at the link box positions which will consist of four earth rods driven into the ground and connected via earth tape to provide a low resistive connection to earth. The joint bays will be backfilled with CBS to ensure that the cables are stabilised from future thermo-mechanical movement. Following CBS backfill subsoil and topsoil would be reinstated above the joint bay.

269. All excavation and reinstatement activities for the joint bays would be conducted in the same manner as that described above for the cable trenching activities.

5.6.1.3.7 Link boxes

270. Link boxes are required in proximity (within 10m) to the jointing bay locations to allow the cables to be bonded to earth to maximise cable ratings, as described above. Link boxes would not be required at all jointing bay locations but as a worst case it is assumed that they could be required up to a frequency of one every 500m. The number and placement of the link boxes would be determined as part of the detailed design.

271. The link boxes would require periodic access by technicians for inspection and testing. Where possible, the link boxes would be located close to field boundaries and in accessible locations.

272. The link boxes need to be accessible during the operation of the cables and would be buried to ground level with above ground marker posts to locate them, and will include a secured access panel. Alternatively link boxes may be above ground in cabinets with a footprint of approximately 1m x 1.5m, and up to approximately 1.5m tall.

5.6.1.3.8 Construction drainage

273. Surface water drainage will be installed along the edge of the working width to intercept surface water, to minimise water within the trench and to ensure the construction works do not increase the risk of flooding to surrounding land.

274. The cable corridor will be bounded by parallel drainage channels (one on each side) to intercept drainage within the working width. Additional drainage channels will be installed to intercept water from the cable trench. This will be discharged at a controlled rate into local ditches or drains via temporary interceptor drains. Depending upon the precise location, water from the channels will be infiltrated or discharged into the existing drainage network.

275. Detailed construction drainage will be developed post-consent by a specialist drainage contractor, taking into account existing land drainage and will include details of header drains, outfall locations and cross-easement interconnections (if applicable). A soakaway drainage pit / outfall may be required if no suitable outfall to a nearby watercourse is possible.

276. Post-construction agricultural drainage will be reinstated including the replacement of any drains that were damaged during the construction process.

5.6.1.3.9 Soil management

277. Stripped topsoil and excavated subsoil will be stored separately within the onshore cable corridor. The area to be used for storing the topsoil would be cleared of vegetation and any waste arising from the development (e.g. building rubble and fill materials). Topsoil would also be stripped from any land to be used for storing subsoil.

278. Effective stockpiles would be created by:

- Removing vegetation and waste materials from the area before forming stockpiles;
- Storing topsoil and subsoil layers separately;
- Locating stockpiles away from trees, hedgerows, drains, watercourses or excavations;
- Managing the site so that soil storage periods are kept as short as possible;
- Stockpiling soils in the driest condition possible;
- Using tracked equipment wherever possible to reduce compaction; and
- Protecting stockpiles from erosion by seeding or covering them.

5.6.1.4 Cable pull

279. Cables would be pulled through the pre-installed ducts later in the construction programme (refer to **Section 5.7**). Trenches would not need to be reopened, and the cable pull would take place from jointing bays located every 500m along the cable corridor.

280. Typically this would be achieved by accessing the onshore cable corridor directly from the existing accesses (i.e. the existing road network where it crosses the cable corridor or from other accesses such as existing farm tracks) where possible. Sections of the haul road would need to be retained following the duct installation works or be reinstated to allow access to more remote joint locations. On this basis, it would be possible to reinstate sections of the haul road immediately following duct installation where access to the joint locations is possible from the existing road network. However, at this stage it is unknown exactly what proportion of the haul road would need to be retained and as a worst case it is assumed that 100% of the haul road would remain in place throughout the cable pulling works.

281. During the cable pull and jointing works cable drums would be delivered by HGV low loader to the open joint bay locations and a winch attached to the cable. The cable would then be winched off the drum from one joint pit to another, through the buried ducts. Cable jointing would be conducted once both lengths of cable have been installed within each joint bay.

282. The cable pulling and jointing process would take approximately eight weeks per 800m length of cable. However, any one joint bay could be open for up to 16 weeks to allow its neighbouring joint bay to be opened and the cables pulled from one pit to the next, dependant on the level of parallel work being conducted.

5.6.1.5 Crossing methods

283. All crossings are listed within a crossing schedule provided as **Appendix 5.1** to this chapter.

5.6.1.5.1 Trenchless crossings

284. Major crossings, such as major roads, river and rail crossings will be undertaken using trenchless crossings techniques such as HDD. The HDD process involves drilling underneath the feature being avoided. The process uses a drilling head to drill a pilot hole along a predetermined profile based on an analysis of the ground conditions and cable installation requirements. This pilot hole is then widened using larger drilling heads until the hole is wide enough to fit the cable ducts. Bentonite is pumped to the drilling head during the drilling process to remove drill cuttings and to stabilise the hole and ensure that it does not collapse. Once the HDD drilling has taken place the ducts are pulled through the drilled hole. When crossing main rivers or Internal Drainage Board (IDB) maintained watercourses the cable entry and exit pits will be at least 9m from the banks of the watercourse, and the cable will be at least 2m below the channel bed.

5.6.1.5.2 Minor road crossings

285. Where the onshore cable corridor crosses minor roads, tracks and public rights of way, open cut trenching methods are proposed in combination with traffic management. Where appropriate, single lane traffic management would be utilised during installation with signal controls to manage traffic movement. Where the width of the road does not permit single lane traffic management, alternative methods such as temporary road closure or diversion could be required. Where standard traffic management techniques are not deemed to be suitable it may be necessary to revert to a trenchless crossing solution. The proposed crossing method for each road crossing is provided in the crossing schedule (**Appendix 5.1**).

286. The approach for each crossing would be agreed with the relevant authority prior to works beginning. Temporary closures or diversions would only be required for the duration of time that duct installation takes place in that location (no more than 1-2 weeks for a minor road crossing). Temporary crossings of the onshore cable corridor could then be installed to allow public access to continue where the haul road is required to remain in service. The crossings would be managed to allow safe operation.

287. Re-instatement of the trench would broadly follow the same process described for the cable duct installation in **Section 5.6.1.3**; however the road surface would be reinstated to a specification agreed with the local highway authority.

5.6.1.5.3 Minor watercourse crossings

288. Where minor watercourses, which are not maintained by IDB, such as field drains, are to be crossed, the approach will be open cut trenching combined with temporary damming and diverting of the watercourse. The suitability of this method would be agreed at detailed design.

289. The watercourse would be dammed at either side of the cable crossing point, typically using sandbags and ditching clay, and the water within the watercourse would be pumped or piped across the dammed section to effectively maintain flow across the dammed section. The cable trenches would then be excavated within the dammed section in the manner described in **Section 5.6.1.3** but ensuring that watercourse bed materials are stored separately to subsoils. Ducts would typically be installed to 2m below the channel bed to avoid impacts to the active channel bed. Reinstatement of the trench would be conducted to the pre-construction depth of the watercourse, taking care to reinstate the channel bed material and subsoils in the order that they were removed. The dams would then be removed. Temporary dam and divert would only be required for the duration of time that duct installation takes place in that location (typically no more than 1-2 weeks for a minor watercourse crossing).

290. The haul road could also require culverting or temporary bridging in these locations to allow continued access up and down the working corridor. These would remain in place for the duration that the haul road is required and would be removed once cable duct installation is complete. Some sections of the haul road may need to be retained to maintain access for the subsequent cable pulling phase.

5.6.1.6 Construction compounds

291. Temporary construction compounds are required to support the onshore cable installation. This will include several secondary compounds and up to two main compounds. In addition, the landfall and substation works would have their own dedicated construction compounds.

292. Up to two main compounds will be required to support the cable duct installation and cable pulling works. These would operate as hubs for the onshore construction works and would house the central offices, welfare facilities, and stores, as well as acting as staging posts and secure storage for equipment and component deliveries.

293. The site selection process for the main compound(s) is currently ongoing. We are currently investigating areas of existing surface infrastructure to reduce the need for initial site establishment works. The size of the main compound(s) will be up to 60,000 m^2, however it may be preferable to use two smaller sites. In order to minimise disruption to the local road network we are identifying the most suitable accesses to and from the compounds.

294. The construction works will also require a series of secondary construction compounds that will operate as support bases for the onshore construction works as the cable work fronts pass through an area. They may house portable offices, welfare facilities, localised stores, as well as acting as staging posts for localised secure storage for equipment and component deliveries.

295. Each secondary compound (up to approximately eight in total) would be approximately 2,500m^2 in size with direct access into the construction easement. One of the secondary compounds could be up to 5,000m^2 to provide a second base for welfare and offices given the length of the onshore cable corridor.

296. Other works compounds include the substation construction compound at approximately 10,000m^2, the landfall compound at approximately 5,750m^2, and each trenchless crossing will require its own compound ranging in size between 1,500m^2 - 4,500m^2.

297. Where there is no existing hard standing construction compounds would be constructed by laying a geotextile membrane or similar directly on top of the subsoil which will have stone spread over the top of it to a depth of approximately 350mm of stone chip.

5.6.1.7 Operations and Maintenance

298. There is no ongoing requirement for regular maintenance of the onshore cables following installation, however access to the onshore export cables would be required to conduct emergency repairs, if necessary. Access to each field parcel along the cable corridor would be from existing field entry points where possible or accessing the cable corridor from road crossings.

5.6.1.8 Decommissioning

299. No decision has been made regarding the final decommissioning policy for the onshore cables, as it is recognised that industry best practice, rules and legislation change over time. It is likely the cables would be removed from the ducts and recycled, with the transition pits and ducts capped and sealed then left in situ.

5.6.2 Onshore Substation

300. The onshore substation will be an air insulated (AIS) switchgear design where the high voltage equipment is installed outdoors with open air terminations. Air is acting as dielectric medium between the phase conductors.

301. Two substation site options have been identified and assessed within this PEIR – each option is of sufficient size to accommodate the maximum footprint required for both DEP and SEP. Only one of these two options will be taken forward for the DCO application. The decision on the preferred option will be informed by stakeholder feedback on the information provided in this PEIR, as well as further technical studies and ongoing environmental survey and assessment work.

302. The onshore substation will be constructed to accommodate the connection of both DEP and SEP to the transmission grid. If only one project comes forward the substation will be up to 3.25ha in size. If both projects are taken forward a single substation will be constructed to accommodate both connections and will be up to 6ha in size in the concurrent build out scenario and up to 6.25ha in the sequential scenario (the additional area required in the sequential scenario is to maintain safe standoff distances once the first project goes live).

303. A new permanent operational access will be required to access the onshore substation, The exact location of this permanent access will be determined post-PEIR but will be located within the existing PEIR boundary.

304. The substation will include:

- Control building;
- Static var compensator (SVC) building if required;
- Transformers;
- Switchgear;
- Shunt reactors;
- Harmonic filters if required;

- Access roads – for operation and maintenance access to equipment; and
- Associated connections between equipment via busbar and cabling, including lightning protection and buried earthing system.

305. The largest structures within the onshore substation listed above will be the control building and SVC building with an approximate height of 15m. The main electrical equipment (transformers etc.) will not exceed a height of 15m. The tallest features within the onshore substation site will be the lightning protection masts at a height of 30m above ground level.

5.6.2.1 Onshore substation parameters

306. **Table 5-31** shows the main construction parameters for the onshore substation.

Table 5-31: Onshore substation construction parameters

Onshore substation	Worst case parameters		
	DEP/SEP in isolation	DEP/SEP together – concurrent	DEP/SEP together – sequential
Operational compound (excluding access)	Up to 3.25ha	Up to 6ha	Up to 6.25ha
Substation control / switchgear building	30m long x 14m wide x 15m high	50m long x 14m wide x 15m high	2 x (30m long x 14m wide x 15m high)
Maximum building height	Up to 15m		
Lightning protection masts	Up to 30m		
All other external equipment	Up to 15m		
Construction compound	Up to 1ha		

5.6.2.2 Location

307. The two onshore substation site options are located in arable land south of the existing Norwich Main substation (**Figure 5.10**). Site 1 is located approximately 250m south of Norwich Main, immediately west of the Norwich to Ipswich rail line, and approximately 600m north of the nearest village (Swainsthorpe). Site 2 is located approximately 150m south west of Norwich Main and approximately 1km east of the nearest village (Swardeston).

308. Only one of these options will be taken forward within the DCO application. The exact location of the preferred substation site option, and associated operational access, will be established post-PEIR.

5.6.2.3 Onshore substation construction method

309. The site would be stripped and the ground levels graded as required by the final design. Stripped material would be reused on site where possible, potentially as part of any identified bunding or screening identified through the impact assessment process.

310. Deeper soils would be excavated from areas where the ground profile needs to be lowered (cut) and moved into the areas where the ground level needs to be raised (fill). The thickness of each fill layer would need to be determined in accordance with the specification of the material and the design of the substation platform. Where the specification of the existing soils is not up to the required load bearing standard additional material may need to be imported to the site. Any excess material would be disposed of at a licenced disposal site.

311. After grading of the site is complete, excavations would then proceed associated with the laying of foundations, trenches and drainage. At this stage it is not known whether the foundations would be ground-bearing or piled. This will be determined by geotechnical ground investigation post-consent that will inform the detailed design. However, for the purposes of the assessment piled foundations are assumed to be required at the substation.

312. Following completion of the cut fill exercise and installation of drainage and foundations the substation platform will need to be finished with a layer of imported stone fill combined with a concrete pour. The thickness of this concrete platform would be determined during detailed design based on the geotechnical ground investigation.

313. The buildings would likely be constructed from a steel frame with cladding panels. The steel frame would be fabricated off site and then erected at the substation location with the use of cranes. The cladding would be fitted once the framework is in place.

314. The substation electrical equipment would then be delivered to site and installed. Due to the size and weight of assets such as the transformers, specialist delivery methods would be employed and assets would be offloaded at site with the use of a mobile gantry crane.

315. The onshore substation would be enclosed by a temporary perimeter fence for the duration of the construction period with a permanent fence installed as part of the construction works.

316. The 400kV cables from the onshore substation to the existing Norwich Main substation would be typically installed by direct bury method. This method will require a trench to be excavated between the onshore substation and Norwich Main (up to approximately 250m in length) for the cables to be laid directly and jointed before being reinstated. Should any sensitive features be located along the route from the preferred substation location to the existing substation at Norwich Main then trenchless crossings may also be required. The working width, trench depth, trenchless crossing width, and other dimension for the 400kV installation would be the same as those described for the main cable duct installation (**Section 5.3.2**).

5.6.2.4 Drainage

317. A surface water drainage system would be required for the operational substation and would be designed to meet the technical requirements set out in the National Planning Policy Framework (NPPF) through the use of infiltration techniques which can be accommodated within the area of development and surface water discharge rates controlled to prevent any increase in flood risk to surrounding land from present day levels.

318. Some form of surface water attenuation would be required with sufficient capacity to retain a peak rainfall event (100 year event + climate change)with controls to ensure that water discharge back to the surrounding area matches the existing greenfield runoff rates, discharging into the closest watercourse or sewer connection. The full specification for the water attenuation and drainage system would be addressed as part of detailed design post-consent.

319. Foul drainage would be collected through a mains connection to an existing local authority sewer system if available or septic tank located within the development boundary. The specific approach would be determined during the detailed design phase with consideration for the availability of mains connection and the number of visiting hours for site attendees during operation.

5.6.2.5 Screening

320. The onshore substation site benefits from existing hedgerows and woodland blocks within the local area. However, it is expected that additional planting to further screen the substation will be identified as part of the final application.

5.6.2.6 Operations and maintenance

321. The onshore substation would not be manned, however access would be required periodically for routine maintenance activities, estimated at an average of one visit per week. Normal operating conditions would not require lighting at the onshore substation, although low level movement detecting security lighting may be utilised for health and safety purposes. Temporary lighting during working hours will be provided during maintenance activities only.

5.6.2.7 Decommissioning

322. No decision has been made regarding the final decommissioning plan for the onshore project substation, as it is recognised that industry best practice, rules and legislation change over time.

323. A full EIA will be carried out ahead of any decommissioning works being undertaken. The programme for decommissioning is expected to be similar in duration to the construction phase of 24-30 months. The detailed activities and methodology for decommissioning will be determined later within the project lifetime, in line with relevant policies at that time, but would be expected to include:

- Dismantling and removal of electrical equipment;
- Removal of cabling from site;
- Removal of any building services equipment;
- Demolition of the buildings and removal of fences; and
- Landscaping and reinstatement of the site.

324. The decommissioning methodology cannot be finalised until immediately prior to decommissioning, but would be in line with relevant policy at that time.

5.7 Construction Programme

5.7.1 Offshore Construction

325. A high-level indicative construction programme including the offshore works is presented in **Plate 5-23** and **Plate 5-24** below. The earliest any construction works would start is assumed to be 2024, however there would be a two year period of onshore construction prior to the start of offshore construction. Offshore construction works would require up to two years per project (excluding pre-construction activities such as surveys), assuming DEP and SEP were built at different times. If built at the same time, offshore construction could be completed in two years. Accounting for the development scenarios described in **Section 5.1.1**, there could be a gap of up to one year between the completion of offshore construction works on the first Project and the start of offshore construction works on the second Project.

326. It should be noted that the construction programme is dependent on numerous factors including consent timeframes and funding mechanisms. The final design of DEP and SEP (including for example whether the integrated or separated grid option is taken forward, the number and type of turbines, OSP/s, cables, etc.) will also affect the construction programme, as well as weather conditions once construction starts. As such, details of the construction programme are indicative at this stage in order to provide a reasonable and realistic basis for undertaking the environmental assessments.

327. Offshore (seaward of mean low water) working hours during construction are assumed to be 24/7.

5.7.2 Onshore Construction Programme

5.7.2.1 Pre-construction works

328. Pre-construction works are expected to take place from 2024. The main pre-construction activities are noted below and would be applicable to the onshore substation and works to install the onshore export cables:

- Ground investigations and pre-construction surveys;
- Road/junction modifications and any new junctions off existing highways;
- Pre-construction drainage – installation of buried drainage along the cable corridor and at the substation, which requires an understanding of the existing agricultural drainage environment;
- Hedge and tree removal – hedge and tree removal is seasonal and can be influenced by ecological factors. Removing these ahead of the main works mitigates against potential programme delays;
- Ecological mitigation – any advanced pre-construction mitigation activities, for example installation of great crested newt fencing; and
- Archaeological mitigation – pre-construction activities agreed with Historic England and Norfolk Historic Environment Services.

5.7.2.2 Main works

329. A high-level indicative construction programme including the onshore works is presented below. The programme illustrates the likely duration of the major installation elements, and how they may relate to one another in the three potential build out scenarios, i.e. either DEP or SEP in isolation, DEP and SEP built concurrently, and DEP and SEP build sequentially.

330. The earliest construction start date for the main works is expected to be 2025 and the latest is 2028.

331. Onshore construction (landward of mean low water) would normally only take place between:

- 0700 hours and 1900 hours Monday to Friday, and 0700 hours to 1300 hours on Saturdays, with no activity on Sundays or bank holidays.

332. Outside of these hours onshore construction work may be required for essential activities including but not limited to:

- Continuous periods of operation, such as concrete pouring, drilling, and pulling cables through ducts; and
- Delivery of abnormal indivisible loads that may otherwise cause congestion on the local road network.

Plate 5-23: Construction Programme – DEP and SEP built in isolation or DEP and SEP built together concurrently

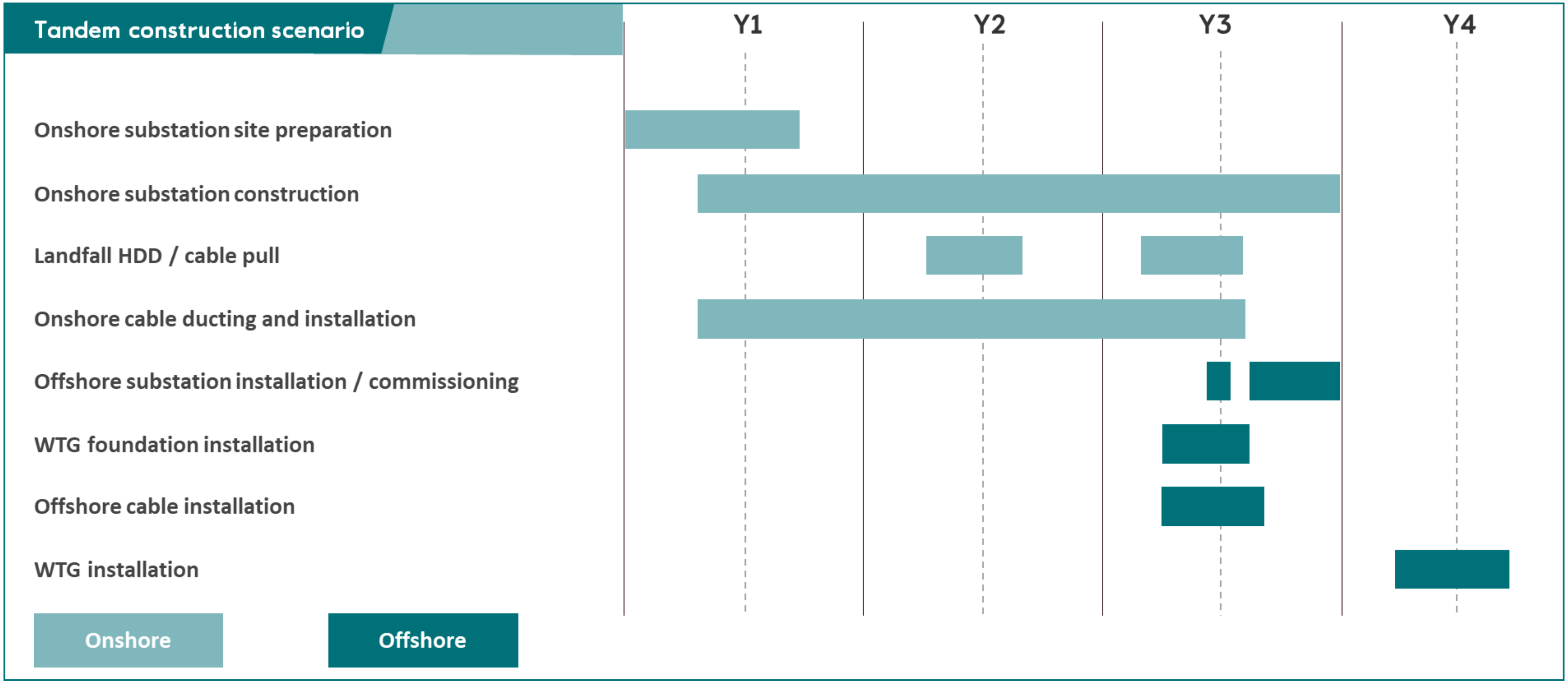
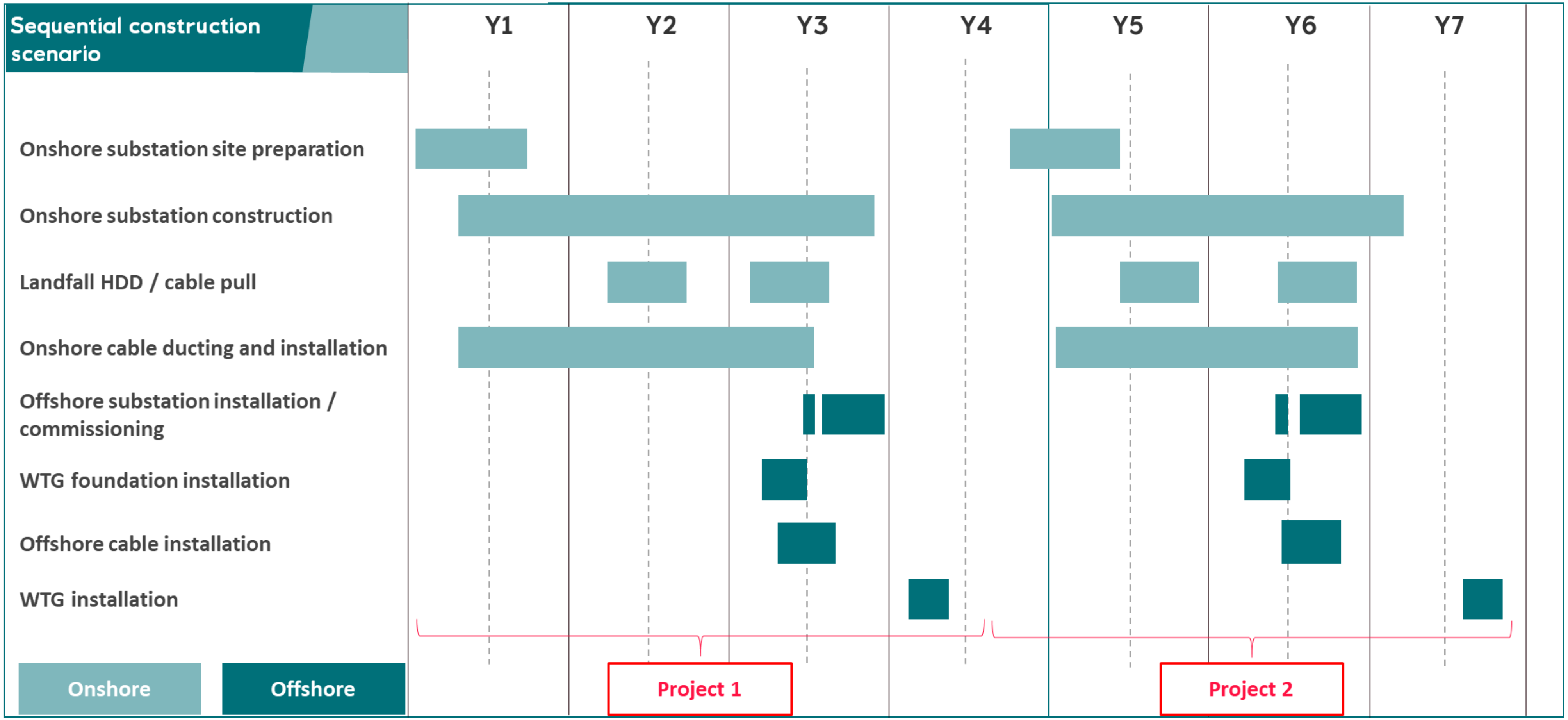


Plate 5-24: Indicative Construction Programme – DEP and SEP built sequentially with up to a 4 year gap between construction start dates



5.7.3 Major Accidents and Disasters

333. The Infrastructure Planning (Environmental Impact Assessment) Regulations 2017 (the EIA Regulations 2017) require the Applicant to consider significant risks to the receiving communities and environment, for example through major accidents or disasters. Similarly, significant effects arising from the vulnerability of the proposed development to major accidents or disasters should be considered. Relevant risks are covered in the topic chapters within this PEIR.

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

335. Offshore wind developments have an intrinsically low risk of causing major accidents. The turbines, blades towers and foundation bases of OWFs have an excellent safety record with a very low failure rate and are positioned many kilometres offshore away from populated areas and the public. On the rare occasion that offshore turbine blades have been lost into the sea or damage has been caused to a turbine by a fire within the nacelle, this has resulted without injury. The performance of each turbine is constantly monitored through the SCADA system sending performance data through to a central, partly automated monitoring and control centre. As a result a problem can be quickly detected and pre-prepared safety management action plans rapidly enacted.

336. Whilst exposed power cables on the seabed can pose a snagging risk to shipping and fishing vessels, the offshore cables will be buried where possible to protect the cables and remove the snagging risk. This is discussed in detail in **Chapter 14 Shipping and Navigation**, which also discusses the risk that the increased vessel movement to and from the site may pose to navigational safety during construction and operational phases.

337. The buried cables onshore and offshore pose very little risk to the public as they are designed to 'trip out' automatically should any failure in insulation along the cable be detected.

338. The risk of substation fires is historically low; however, substation fires can impact the supply of electricity and create a localised fire hazard. The highest appropriate levels of fire protection and resilience will be specified for the onshore project substation to minimise fire risks. The onshore project substation is also located away from populated areas.

339. The small quantities of lubricants, fuel and cleaning equipment required within the Project will be stored in suitable facilities designed to the relevant regulations and policy design guidance.

340. The offshore wind industry strives for the highest possible health and safety standards across the supply chain. However, there have been incidents including a small number of worker fatalities during the construction and operation of OWFs. Risks to the public onshore and sea users offshore during construction have been minimised through the use of controlled construction sites onshore and vessel safety zones offshore.

341. Safety zones are temporary exclusion areas enacted during construction, allowing the Applicant and its contractors to control vessel movements to enable safe construction works to proceed.

342. Onshore, controlled or closed construction sites will be operated where construction works are undertaken, in sections where access is strictly controlled during periods when the works are ongoing.

343. The Applicant recognises the importance of the highest performance levels of health and safety to be incorporated into the Project. There is a commitment to adhere to a high level of process safety, from design to operations and for all staff, contractors and suppliers to have a high level of safety awareness and knowledge of safety and safe behaviour. The Applicant will enact a Code of Conduct for suppliers, contractors and subcontractors. They must all comply with the Code as well as health and safety legislation. The Applicant will ensure that employees have undergone necessary health and safety training.

344. With a commitment to the highest health and safety standards in design and working practices enacted, none of the anticipated construction works or operational procedures is expected to pose an appreciable risk of major accidents or disasters.

345. In conclusion, the risk of 'major accidents and/or disasters' occurring associated with any aspect of the Projects, during the construction, operation and decommissioning phases is negligible.

5.8 References

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