Offshore Transmission: Cost Assessment for the Burbo Bank Extension transmission assets

Draft decision

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Overview:

This document sets out the cost assessment for the Burbo Bank Extension (BBE) offshore transmission assets. This assessment of costs will be used by the Authority to determine the value of the BBE transmission assets to be transferred to the successful bidder.

The assessed costs are reflected in the tender revenue stream which is published in the section 8A licence consultation and we do not expect any further changes to the assessed costs. However, we do not intend to finalise the transfer value until the Authority has determined to grant an offshore transmission licence to the successful bidder.

Context

A key part of the offshore electricity transmission regime is that an offshore electricity transmission licence will be granted to an Offshore Transmission Owner (OFTO) following a competitive tender process run by Ofgem.

The Electricity (Competitive Tenders for Offshore Transmission Licence) Regulations 2015 ("the Tender Regulations") came into force on 3 August 2015. The Tender Regulations set out the tender process framework for granting an OFTO licence, including how Ofgem will run future tenders under both the generator build and OFTO build options.

The Tender Regulations set out the requirement for the Authority to calculate, based on all relevant information available to it, the economic and efficient costs which ought to be, or ought to have been, incurred in connection with developing and constructing the offshore transmission assets in respect of a project. The Tender Regulations provide for an estimate, followed by an assessment of costs, in relation to offshore transmission assets.

Where the Authority has determined to grant an offshore electricity transmission licence to the successful bidder in respect of a particular project, the assessment of costs shall be used by the Authority to determine the value of the transmission assets to be transferred to the successful bidder. This value will be reflected in the revenue stream in the offshore electricity transmission licence granted to the OFTO.

Associated documents

- The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 Link
- Offshore Transmission: Tender Rules Link
- Interest During Construction for Transitional Tender Rounds Link
- Offshore Transmission: Guidance for Cost Assessment Link

Contents

Executive Summary

This document sets out Ofgem's assessment of the economic and efficient costs which ought to have been incurred in connection with the development and construction of the transmission assets for the Burbo Bank Extension (BBE) offshore transmission project ("the Project"). It also details the cost assessment process we have undertaken.

The cost assessment process involved the three key stages set out below:

- The initial calculation of costs based on the Developer's (Burbo Extension Ltd) initial estimate was £230.2m ("the initial transfer value"). This was communicated by Ofgem to the Developer and published in the preliminary information memorandum (PIM) in April 2016;

- The indicative estimate of costs was £180.6m ("the indicative transfer value"). The estimate was calculated as a result of further information regarding the development and construction of the Project being made available by the Developer and continuing analysis by Ofgem and its advisors. This updated calculation was communicated to the Developer in February 2017. The indicative transfer value was made available to bidders at the Enhanced Pre-Qualification (EPQ) stage of the tender process and was the transfer value assumed for the purpose of Invitation To Tender (ITT) stage submissions; and

- The final assessment of costs is £193.9m ("the assessed costs"). This is a reduction of £1.9m from the Developer's final submission of £195.8m. The Developer has confirmed that the incoming Offshore Transmission Owner (OFTO) will be able to obtain the full benefit of all available capital allowances. Therefore, the final assessed cost of £193.9m is the amount to be paid to the Developer by the OFTO for the transmission assets ("the final transfer value").

The key components of the initial, indicative and final transfer values, together with the Developer's submission for the latter, are given in table 1 below.

Table 1: Summary of cost components

Category	Initial Transfer Value March 2016 (£m)	Indicative Transfer Value February 2017 (£m)	Developer Proposed Transfer Value October 2017 (£m)	Final Transfer Value December 2017 (£m)
Capex	155.6	141.6	148.7	152.6
Development	42.9	25.3	29.7	24.1
Contingency	13.3	0.6	-	-
IDC	16.1	10.8	14.8	14.6
Transaction	2.3	2.3	2.6	2.6
Total	**230.2**	**180.6**	**195.8**	**193.9**

Capital expenditure (Capex)

The Capex component of the final transfer value (FTV) has increased by £11m since the indicative transfer value (ITV), due to a number of increases and decreases as set out below.

Increases of:

- £7.7m due to reallocation of costs from Development to Capex;
- £2.5m due to inclusion of onshore substation and offshore substation travel and project management costs that were disallowed at ITV;
- £2.8m due to inclusion of offshore platform fabrication costs that were disallowed at ITV;
- £0.3m due to inclusion of onshore substation site running costs that were disallowed at ITV;
- £1.3m due to inclusion of sea cable installation costs that were disallowed at ITV;
- £0.7m in foreign exchange movements.

These increases were offset by the following reductions:

- £2.6m due to various cost variations;
- £1.1m in disallowed onshore substation costs;
- £0.3m in disallowed spare subsea cable costs;
- £0.3m in disallowed foreign exchange losses.

Development costs

The Project's development costs have decreased by £1.2m since the ITV. The decrease is mainly due to the inclusion of Development costs that were disallowed at ITV being offset by the reallocation of construction costs, included in the submitted Development costs, to Capex, and the reallocation of some Development costs to generation assets.

Contingency

£0.6m of contingency was allowed in the ITV. This has been removed by the Developer in its final cost submission.

Interest during construction (IDC)

The IDC amount has increased by £3.8m since the ITV. This increase is mainly due to changes to the Project's cash flow as set out above.

Transaction costs

The transaction costs are composed of both internal and external resource costs arising from the Developer's participation in the tender process. These have increased by £0.3m since the ITV. The increase is due to additional resource being required to close out the project. Transaction costs have been assessed at £2.6m.

Final transfer value for the BBE transmission assets

In accordance with Regulation 4(2)(b) of the Tender Regulations, the assessed costs of the BBE transmission assets are £193,903,035. The final transfer value as determined by the Authority under Regulation 4(6) of the Tender Regulations is £193,903,035.

1. The cost assessment process

Chapter Summary

The Tender Regulations set out the requirement for the Authority to calculate, based on all relevant information available to it, the economic and efficient costs which ought to be, or ought to have been, incurred in connection with developing and constructing the offshore transmission assets in respect of a project. This chapter sets out the process that we followed in carrying out the cost assessment for the Project.

Overview of the cost assessment process

1.1. The Tender Regulations provide the legal framework for the process which Ofgem follows for the grant of offshore electricity transmission licences. This process includes calculating the economic and efficient costs of developing and constructing the offshore transmission assets to be transferred to the new OFTO.

1.2. The calculation of those costs shall be:

- Where the construction of the transmission assets has not reached the stage when those transmission assets are available for use for the transmission of electricity, *an estimate* of the costs which ought to be incurred in connection with the development and construction of those transmission assets; and

- Where the construction of the transmission assets has reached the stage when those transmission assets are available for use for the transmission of electricity, *an assessment* of the costs which ought to have been incurred in connection with the development and construction of those transmission assets.

Cost assessment principles

1.3. The cost assessment principles and overall process we have adopted in relation to various cost categories for tender rounds and the reasoning for such principles can be found in the document 'Offshore Transmission: Guidance for Cost Assessment'[1] (hereafter "the Guidance").

1.4. We have applied these principles in our cost assessment process for all the projects and, where appropriate, we have taken into account project specific circumstances.

[1] Offshore Transmission: Guidance for Cost Assessment, July 2017

1.5. The remainder of this chapter describes some of the key elements of the cost assessment process. Chapter 2 provides the detail as to how these have been applied to the specifics of the Project.

Data collection

1.6. To undertake cost assessments we gather and review a range of information and supporting evidence. These relate to the forecast and actual costs of developing and constructing the transmission assets that will transfer to the OFTO. Detailed cost information is provided by the Developer in the form of cost reporting templates, contract values, asset cost schedules and cashflows. The Developer also provides supporting evidence to substantiate its cost submissions including, amongst other things, contract documentation, supplier payment lists and invoices and receipts.

1.7. We have worked closely with the Developer and gathered information relating to the following cost categories in the development and construction of the transmission assets:

- Capital expenditure;
- Development costs;
- Contingency provisions;
- Interest during construction; and
- Transaction costs.

Process stages for cost assessment

1.8. The cost assessment process involves the key stages set out below.

Initial transfer value

1.9. The initial transfer value is based on cost submissions by the Developer for the project. This value is made available to bidders at the Pre-Qualification (PQ) or Enhanced Pre-Qualification (EPQ) stage of the tender process. The letter we send to the Developer at this time indicates that the calculation might be updated as a result of any further information provided by the Developer and our continuing analysis.

Indicative transfer value

1.10. We provide the ITV for the commencement of the Invitation to Tender (ITT) stage of the tender process. This value is used as an assumption underlying the tender revenue stream (TRS) bids submitted by bidders at the ITT stage. The letter we send to the Developer confirming the ITV indicates that the calculation might be updated as a result of any further information provided by the Developer and our continuing analysis.

Assessed costs

1.11. Once the transmission assets are complete or are close to completion and the Developer indicates that they have documentation to support an assessment, we commence an exercise to determine the assessed costs.

1.12. Following this assessment exercise, Ofgem sends the Developer a draft cost assessment report setting out the amount of the assessed costs. This gives the Developer the opportunity to correct factual errors and propose redaction of commercially sensitive information.

1.13. The draft report is also sent to the preferred bidder, to allow it to incorporate the assessed costs into their estimate of the TRS payable to the OFTO. This TRS amount, incorporating the assessed costs, is published in a consultation pursuant to section 8A of the Electricity Act 1989, by which the Authority proposes modifications to the standard conditions of the licence on a project specific basis ("the section 8A consultation")

1.14. The draft cost assessment report is published alongside the section 8A consultation. The report remains in draft form until the conclusion of the section 8A consultation and the Authority has determined to grant an offshore transmission licence to the successful bidder.

Final transfer value (FTV)

1.15. If the Developer retains some of the benefit of the available capital allowance we will reduce the relevant amount from the assessed costs before we derive the final transfer value. The FTV is confirmed once the Authority has determined to grant an offshore transmission licence to the successful bidder. After licence grant the final cost assessment report and supporting appendices is published on the Ofgem website.

1.16. Ofgem normally finalises the assessment of costs prior to commencement of the section 8A consultation, with the section 8A TRS accounting for 100% of the FTV.

Cost assessment analysis

1.17. We apply two tests when calculating the estimate and assessment of costs:

<u>Test 1 - Assessing the accuracy and allocation of Developer's cost submissions</u>

1.18. As a first test, we check the accuracy of the data provided by the Developer and the appropriateness of cost allocations, in particular, between the offshore generation and transmission assets. Throughout the cost assessment process the Developer provides cost information to us on an ongoing basis. Where we identify discrepancies in how the Developer has allocated these costs we check with the Developer to assess if they have been allocated to the correct asset category and make adjustments accordingly.

1.19. To support the cost assessment process we undertake a forensic accounting investigation. The scope of this investigation is shared with the Developer in advance. This investigation is based on the final costs that the Developer provides to us and applies to a sample of contract costs. The actual sample for each project varies due to the different contracting strategies adopted by the Developer and the specific needs of the project, but generally focuses on the most expensive contract and/or contracts which materially increase in cost.

1.20. The forensic accounting investigation scrutinises the cost allocations provided by the Developer. This may indicate the need for amendments to the Developer's submissions to reflect, for example:

- The actual costs incurred (e.g. in respect of exchange rates on foreign currency payments); and
- More relevant metrics for the allocation of shared service costs.

1.21. Where amendments in our opinion are required and in the absence of further evidence from the Developer to substantiate the original allocation, we incorporate the recommended changes from the forensic accounting investigation.

<u>Test 2 - Assessing if a Developer's incurred costs are economic and efficient</u>

1.22. Under the second test, we seek to assess, through appropriate analysis, whether the costs have been economically and efficiently incurred by the Developer. Where possible, we apply benchmarking and where industry wide cost indices are unavailable we review data from projects in the tender rounds. This analysis includes benchmarking across the projects and analysis in relation to funding interest rates. We consider such approaches to be an important tool in assisting us in determining what the economic and efficient costs should be.

1.23. To inform our cost estimate and assessment we undertake a benchmarking exercise. This is carried out using comparable costs across all transitional and enduring projects and any wider industry data to identify any cost outliers across the main cost categories. Any cost outliers we identify through the benchmarking exercise are subject to further review.

1.24. We also consider the procurement processes adopted by the Developer to obtain economic and efficient transmission asset costs. We will keep the efficiency of Developer procurement and contract management approaches under review for future cost assessments.

1.25. When undertaking the assessment of costs to derive the FTV, we review updated information provided by the Developer. Where Capex or development costs have increased since the ITV, the Developer is asked to provide supporting documentation to justify these increases. We may undertake a technical investigation which focuses on, for example, a particular cost component, such as an increase of costs in a contract or multiple increases across several contracts.

2. BBE Cost Assessment

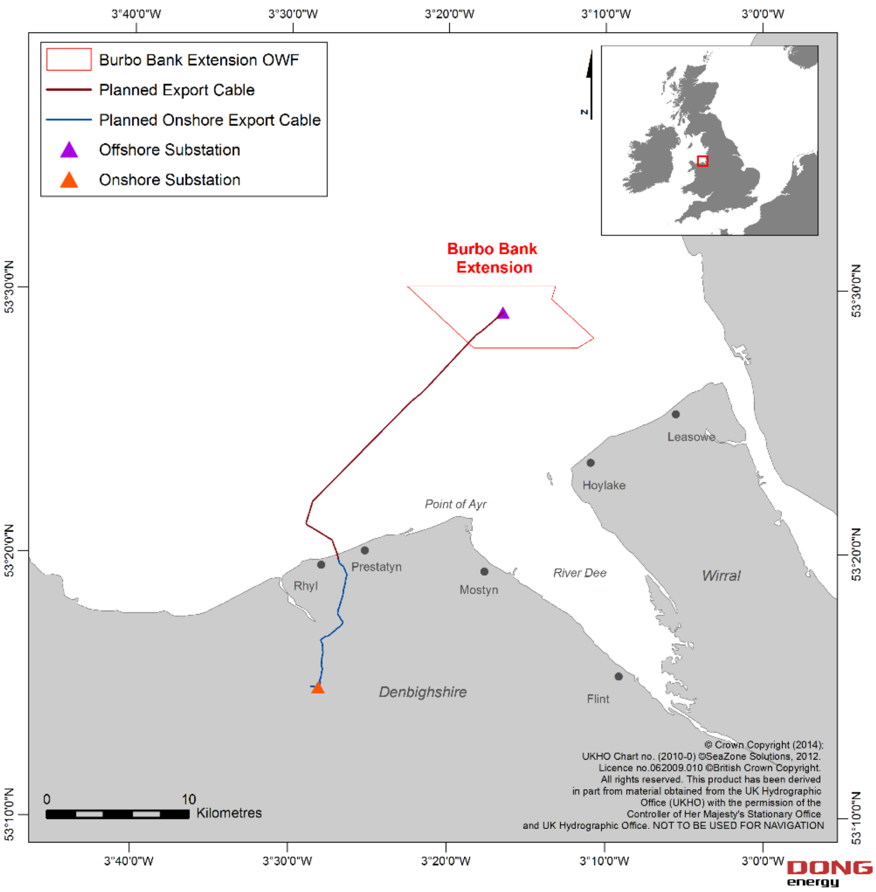
Chapter Summary

This chapter summarises how we have undertaken our cost assessment for the BBE transmission assets from the initial transfer value to the final transfer value. It provides a breakdown of the key cost categories that we have considered and highlights the decisions that we have made.

BBE Transmission Assets

2.1. The BBE Wind Farm is located in the Bay of Liverpool, approximately 20km from Liverpool, as shown in Figure 1 below. The BBE Wind Farm consists of 32 8MW WTGs with a Transmission Entry Capacity ("TEC")[2] of 254.2 MW, which will be connected to an offshore substation platform ("OSS") located within the boundaries of the BBW02 Offshore Wind Farm[3].

Figure 1 – Location of the BBE Wind Farm and Transmission Assets



[2] Transmission Entry Capacity (TEC) is a CUSC term that defines a generator's maximum allowed export capacity onto the transmission system.

[3] The difference between installed and connected capacity is attributed to transformer and array cable losses. NGET has agreed a figure of 250MW which can be exported at the onshore boundary point (Transmission interface point – TIP).

2.2. The BBE Wind Farm is owned by Burbo Extension Ltd, which is jointly owned by Ørsted A/S (50%), KIRKBI A/S (25%) and PKA[4] A/S (25%) (collectively 'the Developer').

2.3. The BBE transmission assets connect to the BBE Wind Farm at one offshore platform. The transmission assets that are transferring to the OFTO comprise:

- One offshore platform and associated electrical equipment;
- One subsea export cable of approximately 24.3km;
- One onshore cable of approximately 10.4km; and
- One onshore substation at St Asaph.

2.4. The boundary points for the BBE transmission system are defined below:

- Offshore: located at the 33kV LV terminals of the 220/34kV transformer; and
- Onshore: located in the gas barrier zones of both the main and reserve 400kV bus bars contained within the existing NGET Bodelwyddan 400kV substation.

2.5. The spares included in the transmission assets that are transferring to the OFTO are:

- 1.4km of subsea cable;
- Various joints (transition, straight and cable repair joints);
- Cable terminations; and
- Other miscellaneous spares.

BBE cost assessment process overview

2.6. We received the first cost information from the Developer in January 2016. We have worked with the Developer and our advisers to reach an assessment of the costs which ought to have been incurred in connection with the development and construction of the transmission assets. Set out below is an outline of the steps taken in the cost assessment process for the Project.

- March 2016: initial transfer value (£230.2m) published.
- February 2017: indicative transfer value (£180.6m) determined.
- March 2017 – June 2017: Cost reporting updates by the Developer over the course of the construction of the project and Ofgem's investigation of allocation methodology for shared costs and overall level of resource costs.

[4] Being the three funds: The State Registered Nurses' and Medical Secretaries' Fund, The Healthcare Professionals' Pension Fund and The Social Workers' Social Pedagogues' and Office Staff Pension Fund.

- July 2017: Forensic accounting for FTV undertaken.
- September-October 2017: Final cost reporting updates and final supporting information received from the Developer.
- February 2017: Draft cost assessment report released to the Developer for comment and the preferred bidder for information.
- March 2018: Draft cost assessment report published alongside the section 8A consultation.
- [TBC] 2018: The Authority determines the final transfer value when it determines to grant the licence to the successful bidder. The final cost assessment report is published after licence grant.

Summary of Indicative Transfer Value determination

2.7. The initial transfer value calculated in March 2016 was £230.2m. This value was based on information received from the Developer at an early stage in the construction and development of the Project. A number of the Developer's contracts were in the process of being finalised at the initial transfer value stage and these were considered in greater detail when the indicative transfer value was set.

2.8. The ITV of £180.6m was established in February 2017. Our estimate was supported by our forensic accounting advisors, Grant Thornton ("GT"), our internal analysis and the supporting information provided by the Developer.

2.9. When we set the ITV we reduced Development costs by £16.9m, to bring these costs in line with the level observed on comparable projects.

2.10. At the ITV stage, we agreed to further review the overall level of Development costs, along with the methodology applied to apportion the costs of resources which are shared between transmission and generation assets, at the FTV stage.

Process for determining the final assessed costs

Accuracy and Allocation

2.11. The Project was constructed on a multi-contract basis. A forensic accounting investigation was undertaken by GT to ensure that the costs reported to us by the Developer were accurate, in that they represented the actual costs incurred by the Developer during the development and construction of the Project.

2.12. This investigation considered the main contracts in respect of the transmission assets for the following:

- The offshore substation and platform;
- The offshore cable supply and installation;

- The land cable supply and installation;
- Onshore civil engineering works; and
- Onshore connection costs.

2.13. We also checked that the costs were allocated to the correct asset category, in particular between generation assets and transmission assets. To assess whether the costs were allocated correctly we took into consideration the following:

- Metrics used when allocating costs between generation and transmission;
- The Developer's submissions using our cost reporting template;
- The findings of the forensic accounting investigation; and
- Cashflow payments related to the transmission assets.

Efficiency

2.14. After costs had been appropriately identified and allocated, we performed an assessment of whether these costs had been incurred economically and efficiently. This involved an internal benchmarking review and a technical investigation undertaken by our advisors.

Summary of assessment

2.15. Following completion of the development and construction of the transmission assets, the Developer submitted costs amounting to a proposed final transfer value of £195.8m. Our assessment of the economic and efficient costs which have been or ought to have been incurred, in connection with developing and constructing the transmission assets, has established a final transfer value of £193.9m. Table 2 below provides a breakdown of the cost categories for the Project at each stage and change between the indicative transfer value and the final transfer value.

Table 2: Summary of cost categories

Category	Initial Transfer Value March 2016 (£m)	Indicative Transfer Value February 2017 (£m)	Final Transfer Value December 2017 (£m)	Reasons for change between Indicative Transfer Value and Final Transfer Value
Capex	155.6	141.6	152.6	Increases of: £7.7m due to reallocation of costs from Development to Capex; £2.5m due to inclusion of onshore substation and offshore substation travel and project management costs that were disallowed at ITV; £2.8m due to inclusion of offshore platform fabrication costs that were disallowed at ITV; £0.3m due to inclusion of onshore substation site running costs that were disallowed at ITV; £1.3m due to inclusion of sea cable installation costs that were disallowed at ITV; £0.7m in foreign exchange movements. Offset by decreases of: £2.6m due to various cost variations; £1.1m in disallowed onshore substation costs; £0.3m in disallowed spare subsea cable costs; £0.3m in disallowed foreign exchange variations.
Development	42.9	25.3	24.1	Increase of: £11.7m net of inclusion of costs that were disallowed at ITV and cost variations. Offset by decreases of: £7.7m due to reallocation to Capex; £5.2m due to recalculation of the metrics for allocating the costs of resources which are shared between generation and transmission assets.
Contingency	13.3	0.6	-	Decrease of: £0.6m due to export cable contingency being released.
IDC	16.1	10.8	14.6	Increase of: £4.0m due to cash flow adjustments. Offset by decrease of: £0.2m due to cash flow adjustments from disallowed costs.
Transaction	2.3	2.3	2.6	Increase of: £0.3m due to transaction budget increase
Total	**230.2**	**180.6**	**193.9**	

2.16. The issues we have considered in setting the final transfer value are detailed below.

Capex

2.17. The Capex element of the final transfer value is £152.6m. Overall the Capex has increased by £11m from the ITV to the FTV. As discussed in more detail below, the increase is largely due to reallocating costs from development to Capex; reinstating Capex removed at the ITV stage; and, movements in the exchange rates used to convert costs denominated in foreign currency into GBP. This is offset by reductions reflecting inefficiently incurred costs; the reallocation of costs to generation assets; and, the recalculation of foreign exchange rates.

2.18. GT undertook a forensic investigation of a selected number of Capex contracts. The main Capex contracts investigated were:

- ABB AB - supply of the offshore cable;
- Seaway Heavy Lifting B.V. – installation of the offshore platform;
- JV Cofely Fabricom-Iemants – fabrication of the offshore platform;
- Jan De Null NV – installation of the offshore cable; and
- Balfour Beatty Civil Engineering Ltd– civil works construction of the onshore substation.

Accuracy and allocation of Capex costs

2.19. For the majority of Capex costs incurred on the Project, it was clear whether they should be allocated to the transmission or the generation assets in their entirety. For costs shared between generation and transmission assets, the Developer allocated certain proportions to the transmission assets using cost allocation metrics, which differ depending on the nature of the work undertaken. Only those costs related to the transmission assets were allowed in the final transfer values.

2.20. In conducting our own analysis of these costs there were a number of items whose accuracy and allocation we have discussed with the Developer. These items are set out below.

Foreign Exchange movements

2.21. A number of contracts were denominated in either Euros or Danish Krone. Total exposure amounted to €112.5m (circa. £88m) and DKK282.5m (circa. £29m).

2.22. The Developer stated that it did not hedge against foreign exchange movements, at either a project or a group level, when it made its Final Investment Decision; instead, it sought further clarification from us on the treatment of currency exchange movements. In May 2016, we clarified how we would treat the impact of foreign exchange movements during the cost assessment process. The Developer then placed hedges for the remainder of the committed project costs.

2.23. In its final submission, the Developer included foreign exchange movements of £3.5m from the ITV, for the period between FID and May 2016. These movements were offset by £2.7m of hedging gains. The gains were subsequently re-allocated to the relevant Capex category.

2.24. We reviewed the Developer's foreign exchange contracts and considered the additional information submitted by the Developer to ensure that these foreign exchange movements were calculated correctly. As a result of this review we removed £0.3m from the Developer's submission, reducing the Developer's net claim for foreign exchange movements from £0.7m to £0.4m.

Ofgem's views

2.25. For the period between Final Investment Decision and May 2016, we understand that the Developer placed no hedges, and therefore used the spot rate to calculate values in pounds. For the period from May 2016 to the end of the Project, we included the Developers hedges in the calculation of costs in pounds. This is based on confirmation from the Developer that they did not place any hedges, at either a project or a group treasury level, during this period to cover foreign exchange exposures arising from this project.

2.26. We reviewed the forward rates submitted by the Developer and concluded that a more favourable rate could have been obtained. Therefore, we have removed £0.3m of foreign exchange movements from the Developer's submission, relating to the period between May 2016 to the end of the Project.

<u>Re-allocation of shared Capex from Development</u>

2.27. Since the ITV stage, the Developer indicated that a number of Capex costs had been incorrectly allocated to Development. These are largely costs which are shared between generation and transmission assets and include: construction insurance costs, offshore substation and export cable commissioning costs and offshore construction site and vessels costs.

Ofgem's view

2.28. For the purpose of informing our assessment of the Project's FTV, we have further reviewed these costs and considered the additional information submitted by the Developer. We agree these are Capex costs. As a result, we have a reallocated £7.7m from Development to Capex.

<u>Re-allocation of shared Capex to generation assets</u>

2.29. Shared Capex costs are costs that are not directly attributable to the transmission assets. These costs are shared according to a methodology that is reviewed by Ofgem. In its final cost submission, the Developer allocated circa 33% of shared Capex costs to transmission. We have reviewed the developer's proposed methodology used to allocate shared costs. This review is discussed in more detail in para 2.60 to 2.64, alongside Development costs. Following this review, the Developer agreed to recalculate the metrics used in the final cost submission.

Ofgem's view

2.30. We consider appropriate that a proportion of these costs should be assigned to transmission assets. However, as discussed in more detail in para 2.60 and 2.64, we consider that the allocation should be based on a metric that is robust, transparent and reflects the level of Capex cost directly attributable to transmission assets. We have verified the revised metrics calculated by the Developer and are satisfied they reflect the generation-transmission ratio based on direct Capex only, which for BBE is circa. 25%. As a result, £0.3m of shared Capex costs have been re-allocated to generation assets and excluded from the Project's FTV.

Efficiency of Capex costs

2.31. Following the reallocation of Capex costs from Development, the Developer's final cost submission included a capex increase of £11m.

2.32. The Developer has provided additional information to support these costs. For the purposes of informing our assessment of the efficiency of the project's Capex costs, we have reviewed these costs along with the additional information submitted by the Developer. Our views on whether these increases have been incurred in an economic and efficient manner are discussed below.

<u>Onshore substation costs</u>

2.33. In its final cost submission, the Developer included an increase in onshore substation costs of £2.0m since the ITV. We investigated the factors that led to this increase, and reviewed additional evidence supplied by the Developer. Based on the information provided, we understand the insufficient procurement of land at the start of the Project to be the main driver behind this cost increase.

2.34. The Developer considered that at the start of the Project it purchased enough land for the footprint of the final substation. Early during the construction it became evident additional land was required surrounding the substation to allow an efficient programme of works; this land was subsequently procured. This resulted in additional costs for the procurement and preparation of the additional land as well as additional management resource required to manage the associated additional works. It also had a knock on impact on the programme of works in that some works were delayed due to resource prioritisation.

2.35. The Developer argued that it acted prudently and chose to incentivise its contractors by raising additional variation orders to complete and manage additional works alongside the original programme of works to keep construction on track and to mitigate the possibility of delays.

Ofgem's views

2.36. While we recognise the risks faced by the Project, we are of the view that some of these costs could have been avoided if the selection of the original site was managed efficiently. We do not consider the additional costs to be an economic and efficient spend. Accordingly, we have removed £1.1m from the Developer's submission.

Export cable costs

2.37. The Developer included 2.3km of spare cable for transfer to the OFTO in its final submission. Analysis of the length of spare cable required for a single subsea cable fault for this project was undertaken by a third party's technical consultant, taking into account the project specific conditions along the cable route. They recommended that a minimum of 1.4km of spare cable is required for a worst case repair, in light of the length of the horizontal direction drilling section of the cable.

Ofgem's views

2.38. Our view is that the length of spare cable to carry out a typical subsea cable fault repair on a typical project is 1km. We have considered the rationale for including an additional length of spare cable in the FTV. Based on the view of the technical consultant, taking into account project specific conditions, we agree with the consultants that a length greater than 1km of spare cable is required for BBE. We have therefore only included the cost of 1.4km of spare cable (the minimum recommended length for a worst-case repair). This has resulted in the removal of £0.3m from the Developer's final submission.

Capex disallowed at ITV

2.39. The Developer's final cost submission included a total of £6.9m of Capex costs which were disallowed at the ITV stage.

2.40. Since we set the Project's ITV, the Developer has provided additional information to support these costs. For the purposes of informing our assessment of the efficiency of the project's Capex costs, we have reviewed this information, conducted further analysis and discussed the findings with the Developer.

2.41. We also asked our technical consultant OWC ("consortium between Offshore Wind Consultant Ltd and Xero Energy Ltd") to carry out a detailed investigation of the Project's Capex costs. In particular, our technical consultant investigated, amongst other things, whether the level of project management cost incurred by the Developer was reasonable for a project with the characteristics of BBE.

2.42. The findings from the OWC technical review have been used to inform our assessment of the efficiency of the Project's Capex costs. We have detailed below the main issues that were considered and how we have assessed these costs.

Export cable installation costs

2.43. At the ITV stage we removed £1.3m from the Project's export cable installation costs, based on benchmarking. In setting the FTV, additional work was undertaken to consider these costs and the Developer's supporting evidence.

2.44. The Developer provided additional information and explained that the method for installing the export cable was based on initial assumptions and provisional seabed data. As the Project developed further, more detailed sea mobility studies became available. When seabed characteristics were fully understood, it became clear the methodology chosen for the installation of the cable would not achieve the required depth of burial in some areas of the cable route. Therefore, a change in installation methodology was required in order to achieve the optimal burial depth throughout the entire cable route. The Developer also explained additional mattresses were required in order to meet the requirement of various crossing agreements with third parties. This resulted in higher installation costs, which account for the level of costs submitted by the Developer.

Ofgem's views

2.45. Following the review and careful consideration of the justification provided by the Developer, we are satisfied with the level of costs submitted. Therefore, we have included the additional £1.3m in the FTV.

<u>Offshore platform fabrication and supply costs</u>

2.46. At the ITV stage we removed £2.8m from the Project's offshore platform supply and installation of foundations and topsides as the costs incurred were higher than expected for a 258MW project, based on benchmarking. In setting the final transfer value, additional work was undertaken to consider these costs.

2.47. The Developer provided additional information explaining the offshore platform was sized in order to accommodate 220kV electrical apparatus, which is significantly bigger in size than that used on previous projects. We have considered the additional information provided by the Developer and conducted further analysis.

Ofgem's views

2.48. Based on the information provided by the Developer, we are satisfied that a 220kV system is cost effective for BBE due to the cost savings from a reduced number of sea cables outweighing the cost increase from a larger offshore platform, compared to a 132kV system. Following the review of costs of the offshore platform supply and installation of foundations and topsides, we are satisfied with the level of costs submitted. Therefore, we have included the additional £2.8m in the FTV.

<u>Onshore substation construction site costs</u>

2.49. At the ITV stage we removed £1m of costs related to the onshore substation construction site. A proportion of these costs, £0.3m, have been resubmitted as part of the Project's final transfer value, along with additional explanation and supporting evidence.

2.50. The Developer explained that these are construction costs related to the setting up, running and winding down of the onshore substation construction site. The Developer submitted additional information indicating that the commissioning of the onshore substation electrical apparatus could not be completed until all the turbines had been installed, given a number of tests are performed at "full load". Since construction of the wind farm was completed in April 2017, the onshore substation site was required until 2017, longer than anticipated, in order to complete the parallel commissioning of the onshore substation electrical apparatus.

Ofgem's views

2.51. Following the review and careful consideration of the justification provided by the Developer, we are satisfied these costs were incurred in order to complete the onshore substation commissioning programme. Therefore, we have included additional £0.3m in the project FTV.

<u>Onshore substation and offshore substation project management costs</u>

2.52. While establishing the project ITV, we had significant concerns around the level of project management costs incurred by the Developer, which we considered high for a project of the size and complexity of BBE. In the absence of robust justifications, onshore substation and offshore substation project management costs had been brought in line with those of comparable projects, and were therefore reduced by £12.4m, to circa. 8% of the asset value.

2.53. Since the ITV stage, we have further reviewed the level of project management costs incurred by the Developer, and asked our technical advisor OWC to establish what a reasonable level of project management costs for a project of the size and complexity of BBE should be.

OWC's views

2.54. OWC reviewed the level of project management costs incurred by the Developer in relation to the Project and estimated the standard level of project management costs for such a project would range between 7% and 10% of the cost of the entire project.

Ofgem's views

2.55. We have conducted further analysis and discussed the findings of the OWC review with the Developer, who explained the construction programme of the onshore substation and offshore substation was delayed as a result of storm Gertrude and storm Jonas. As discussed in the previous section, the Developer also explained the project incurred issues during construction of the onshore substation, which required greater project management effort. As a result of further discussion, the Developer agreed to reduce the level of onshore substation and offshore substation project management costs included into its final cost submission to circa 10% of asset value.

2.56. After careful consideration of the justification provided by the Developer, we are satisfied with the reduced level of onshore substation and offshore substation project management costs included into the Developer's final cost submission. We recognise some of these costs were due to events, such as adverse weather conditions, which are outside the Developer's control. As a result, an additional £2.5m, relative to the ITV position, has been included into the Project's FTV.

Development costs

2.57. The assessed development expenditure for the BBE transmission assets is £24.1m. This represents a reduction of £1.2m relative to the costs that were included in the ITV. As discussed in more detail below, the decrease is largely due to the reallocation of costs from Development to Capex and the reallocation of shared resource costs to generation assets. The decrease in Development costs is offset by an increase due to the reinstatement of costs which were excluded from the Project's ITV.

2.58. For the purpose of informing our cost assessment, we have reviewed the cost information provided by the Developer. We also asked our advisors to investigate the Project's resource costs, which was the main component of the submitted Development costs. In particular, we requested OWC to review the way the costs of resources which are shared between transmission and generation assets have been allocated to transmission.

Accuracy and allocation of development costs

2.59. As discussed in paragraphs 2.27 and 2.28 following a further review of the information submitted by the Developer, we have reallocated £7.7m of construction costs from Development to Capex.

<u>Reallocation of shared resource costs to Generation assets.</u>

2.60. Since the ITV, we have undertaken a broad review of the costs of resources which are not directly attributable to either generation or transmission assets. These costs are incurred in relation to a number of activities, including planning and consent, SCADA and Project and Programme Management (PPM) etc., and account for the majority of the Project's Development costs. Since these costs are incurred in relation to the project as a whole, they must be apportioned between transmission and generation via appropriate metrics.

2.61. Historically, developers have used a high-level allocation methodology which assigns the cost of shared resources (along with shared Capex costs) on the basis of the value of the transmission assets compared to the value of the overall wind farm assets (which is typically at a rate of circa. 25%).

For BBE, however, the Developer has allocated a higher proportion of shared resources (and Capex) costs to transmission on the basis of a new, more complex methodology which makes use of a number of different methods of cost allocations. This new allocative approach has resulted in approx. 36% of shared resource (and 33% of shared Capex) costs being assigned to transmission.

2.62. For the purpose of informing our assessment of the Project's FTV, we asked our advisor OWC to review appropriateness of the methods used by the Developer to apportion these costs, amongst other things.

OWC's views

2.63. OWC have identified that a number of different methods have been combined for apportioning the costs of shared resources. These include, amongst others: the area occupied by the transmission assets; ratios based on either contract values or asset values; levelled (weighted) averages; and, judgment by the package manager. OWC have also identified that different methods have been used for allocating resources within the same cost group, e.g. consents and PPM. OWC have raised concerns around the validity of the overall approach, considering it as: somewhat complex; inconsistent; not easily auditable; and, subjective. OWC has recommended that different cost codes should be used for transmission and generation activities in order to reduce the need for allocating costs, and that when an allocation is required, a rate based on relative proportions of direct Capex should be applied more generally.

Ofgem's views

2.64. We have also assessed the basis for the new allocations and we have serious concerns around the lack of objectivity and robustness of the proposed allocative approach. We found significant inconsistencies in the way costs have been split between generation and transmission, with up to 7 different methods used to allocate the same types of costs, and have noted identical types of costs being allocated differently over time. Equally, an allocation based on judgment by the package manager is not only subjective but it also can't be verified. Therefore, in the absence of more robust and reliable allocations, we consider a direct Capex split is a more appropriate method for allocating these costs. Following further discussion, the Developer reallocated the allocation metrics used in its final cost submission, to bring them in line with a split based on direct Capex, which for BBE is circa. 25%. As a result, £5.2m of shared resource costs have been reallocated to generation assets and excluded from the Project's FTV.

Efficiency of Development Costs

<u>Development costs disallowed at ITV</u>

2.65. Development costs submitted at the ITV stage were £42.9m. When setting the Project's ITV, we were concerned by the level of these costs as they appeared well above the level we have observed on other projects. Following discussion with the Developer and in the absence of it being able to provide robust justifications, we reduced Development costs to 15% of Capex. This resulted in the removal of £16.9m from the Project's ITV. However, it was agreed these costs would be reviewed at the FTV stage, when more information would become available.

Ofgem's views

2.66. We have conducted further analysis and further reviewed the level of Development costs submitted. Following the reallocation of costs to Capex and generation assets, we are satisfied with the level of Development costs submitted by the Developer, 15.7% of Capex, which is broadly in line with what we observed on other comparable projects. As a result, £11.7m of costs excluded at the ITV stage have been included in the Project's FTV.

Contingency

2.67. The assessed costs do not contain a separate contingency value. £0.6m of the contingency that existed at the indicative transfer value stage has not been used and therefore it has been removed by the Developer from its final cost submission.

Interest during construction

2.68. In its final submission, the Developer included £14.8m of IDC, a £4.0m increase since ITV. This is based on the Developer's calculation of the IDC to completion of the assets over a period from November 2010 to October 2016. The change since ITV is mainly due to the inclusion of costs disallowed at ITV altering the cash flow.

2.69. The decisions that we made with respect to the Project's Capex costs for the FTV have resulted in a £0.2m reduction in IDC to the Developer's submission. The total IDC calculated for the BBE transmission assets in the assessed costs is £14.6m.

Transaction costs

2.70. The Developer has submitted a firm estimate of the transaction costs they expect to incur to asset transfer. We have reviewed this estimate and assessed transaction costs at £2.6m.

Accuracy and allocation of transaction costs

2.71. We noted that transaction costs included in the Developer's final costs submission included £2.7m of hedging gains.

Ofgem's view

2.72. We consider hedging gains as Capex. Therefore, we have re-allocated the £2.7m hedging gains to the Capex section and considered it there.

Efficiency of transaction costs

2.73. Transaction costs increased by £0.3m since the indicative transfer value. The Developer explained the increase is largely due to the transaction budget being revised up to account for more resources being needed to reach asset transfer.

Ofgem's view

2.74. Transaction costs can only be provided to us by developers to a reasonable degree of accuracy towards the end of the tender process. We have considered the types of resource costs incurred in relation to this Project's tender process and the level of transaction costs incurred appear reasonable in comparison with other projects.

Confirmations in relation to tax benefits

2.75. The ITV was calculated on the basis that the purchaser would obtain the full benefit of all available capital allowances. If this was not the case for the FTV we would reduce the assessment of costs for an amount that reflects the value of the tax benefit retained by the Developer. The Developer has confirmed that the purchaser will be able to obtain the full benefit of all available capital allowances and therefore FTV will be the same as the assessed of costs.

3. Conclusion

3.1. In conclusion, in accordance with Regulation 4 of the Tender Regulations, the Authority has assessed the economic and efficient costs which ought to have been incurred in connection with developing and constructing the BBE transmission assets as £193,903,035.

Appendices

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Appendix	Name of Appendix	Page Number

Appendix 1 - Glossary

A

Authority

The Gas and Electricity Markets Authority

C

Capex

Capital Expenditure

D

Developer

BBE Limited

Xero

A consortium between Xero Energy Ltd and Offshore Wind Consultant Ltd

G

GT

Grant Thornton

I

IDC

Interest During Construction

IM

Information Memorandum detailing the projects details released to QTT bidders through the tender portal.

ITT

Invitation to Tender

M

MW

Megawatt

MVA

Megavolt-Ampere

O

OFTO

Offshore Transmission Owner

P

Project

The development and construction of the BBE offshore transmission assets

PTRA

Post Tender Revenue Adjustment

Q

QTT

Qualification to Tender