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Offshore Transmission: Draft Cost Assessment for the Humber Gateway transmission assets

Draft decision

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Overview:

This document sets out the cost assessment for the Humber Gateway (HG) offshore transmission assets. This assessment of costs will be used by the Authority to determine the value of the HG 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 Electricity Act 1989 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

Ofgem and the Department of Energy and Climate Change have developed a regulatory regime for offshore electricity transmission. A key part of this 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 2013 ("the Tender Regulations") sets out the tender process framework for granting an OFTO licence. The Tender Regulations apply to the HG transmission assets.

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 2013 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 Humber Gateway (HG) 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 (E.ON Climate & Renewables UK Humber Wind Limited) initial estimate was £194.7m ("the initial transfer value"). This was communicated to the Developer and published in the preliminary information memorandum (PIM) in February 2014;

- The indicative estimate of costs was £173.3m (the indicative transfer value (ITV)). 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 March 2015. The ITV was the transfer value assumed for the purpose of Invitation To Tender (ITT) stage submissions; and

- The assessment of costs is £160.3m ("the assessed costs"). Compared to the Developer's final submission of £184.6m, this is a reduction of £24.3m. The assessment is the Authority's calculation of the costs which ought to have been incurred in connection with the development and construction of the Project. The Developer has confirmed that the OFTO in respect of the transmission assets will be able to obtain the full benefit of all available capital allowances. Therefore, this is the amount to be paid to the Developer by the OFTO for the transmission assets (the final transfer value (FTV))

The key components of the initial transfer value, ITV and FTV, together with the Developer's submission for the latter, are given in table 1 below, followed by a summary of the movements between the ITV and the FTV.

Table 1: Summary of cost components

Category	Initial transfer value Feb-14 (£m)	Indicative transfer value Mar-15 (£m)	Developer's proposed transfer value Oct-15 (£m)	Final transfer value May-16 (£m)
Capex	142.2	118.6	136.8	128.0
Development	16.2	27.4	22.7	14.3
Contingency	12.0	6.1	2.8	-
IDC	22.3	18.7	19.6	14.8
Transaction	2.0	2.5	2.6	3.2
Total	**194.7**	**173.3**	**184.6**	**160.3**

Capital expenditure (Capex)

The Capex component of the FTV increased by £9.4m since the ITV, due to a number of increases and decreases as set out below.

Increases of:

- £3.1m for offshore substation commissioning;
- £1.4m for unexploded ordnance clearance;
- £1.1m for 'waiting on weather' costs;
- £1.9m for laying cable duct on nearshore;
- £2.0m for subsea cable storage and installation;
- £0.7m on various minor costs; and
- £11.3m in transfers from Development costs.

These increases were offset by the following reductions:

- £0.9m of land costs; and
- £11.2m of overestimated costs.

Development costs

The Project's development costs have decreased by £13.1m to £14.3m since the ITV. The decrease is mainly due to the reallocation of development costs to Capex, but also includes costs that were overestimated in the ITV.

Contingency

The contingency allowed in the ITV has been used in addressing additional Capex and development costs, while unused contingency has been removed.

Interest during construction (IDC)

The IDC amount has decreased by £3.9m due to: the removal of IDC entitlement during periods of project delays; the reduction of IDC during an extended development phase; and, capex reductions.

Transaction costs

The transaction costs are composed of both internal and external resource costs arising from the Developer's participation in the tender and sale process. These have increased from £2.5m to £3.2m since the ITV. The increase is due to costs continuing to firm-up during the final stages of the project, such as additional legal and technical costs being incurred to prepare the project for transfer.

FTV for the HG transmission assets

In accordance with Regulation 4(2)(b) of the Tender Regulations, the assessed costs of the HG transmission assets are £160,297,985. The FTV as determined by the Authority under Regulation 4(6) of the Tender Regulations is £160,297,985.

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.

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, Ofgem ref 183/12, Dec 2012

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 provided supporting evidence to substantiate their 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.

ITV

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.

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 FTV. 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:

Test 1 - Assessing the accuracy and allocation of Developer's cost submissions

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.

Test 2 - Assessing if a Developer's incurred costs are economic and efficient

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 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. Were 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. HG Cost Assessment

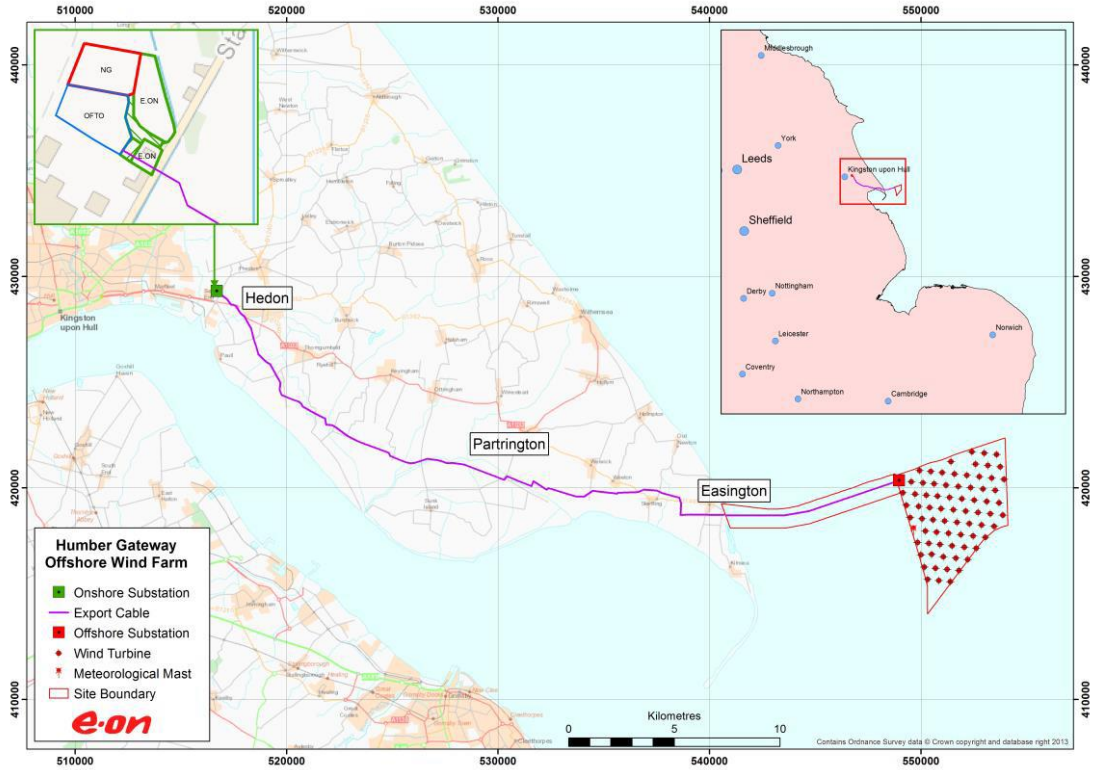
Chapter Summary

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

HG Transmission Assets

2.1. The Humber Gateway Offshore Wind Farm (HGOWF) is located in the UK North Sea, approximately 8km off the coast of the East Yorkshire, as shown in Figure 1 below. The HGOWF consists of 73 3MW wind turbine generators, with a maximum output of 219MW at the OFTO point of connection to the onshore system.

Figure 1 – Location of the HG Offshore Wind Farm and Transmission Assets



2.2. The HGOWF is wholly owned by the Developer, E.ON Climate & Renewables UK Humber Wind Limited, which is a subsidiary of E.ON UK plc and which project forms part of the renewable business of E.ON Climate & Renewables.

2.3. The HG transmission assets connect to the HGOWF at one offshore platform. The transmission assets that are transferring to the OFTO comprise:

- One offshore platform and associated electrical equipment;
- Two subsea export cables of approximately 9km each;
- Two onshore cables of approximately 30km each; and
- One onshore substation at Staithes Road, Salt End, Hull.

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

- Offshore: Located at the 33kv cable box "bushings" on each feeder isolator; and
- Onshore: Located at the 275kV bus bar "clamps" for each of the 4 line isolators.

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

- A 2km length of spare subsea cable;
- Offshore marine repair joints;
- Onshore cable spares; and
- Other substation and miscellaneous spares.

HG cost assessment process overview

2.6. We received the first cost information from the Developer in November 2013. Since then, 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.

- February 2014: Initial transfer value (£194.7m) published.
- March 2015: ITV (£173.3m) published.
- October 2015 – February 2016: Cost reporting updated by the Developer over the course of the construction of the project.
- December 2015: Forensic accounting and technical investigations for FTV undertaken.
- May 2016: Final cost reporting update (including reallocation of Capex from development) and final supporting information received from the Developer.
- June 2016: Draft cost assessment report released to the Developer for comment and the preferred bidder for information.
- [July 2016]: Draft cost assessment report published alongside the section 8A consultation.
- [TBC]: The Authority determines the FTV when it determines to grant the licence to the successful bidder. The final cost assessment report is published after licence grant.

Summary of ITV determination

2.7. The initial transfer value of £194.7m was set in February 2014. 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 ITV was set.

2.8. The ITV of £173.3m was established in March 2015. 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. At the ITV stage, the Project's costs were reduced by £21.4m from the initial transfer value. This comprised reductions of £12.3m for the offshore substation, £3.8m for IDC, £3m for supply and storage of spare cable, £1.2m for land costs and £0.7m for crop compensation costs. There was a further reduction of £2.4m for estimated costs not incurred, offset by an increase of £2.0m in development costs to correct an error in the Developer's submission.

Process for determining the assessed costs

Accuracy and Allocation

2.10. 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.

2.11. 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; and
- The onshore substation.

2.12. 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

2.13. 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 detailed analysis of the costs submitted by the Developer.

Summary of assessment

2.14. Following completion of the development and construction of the transmission assets, the Developer submitted costs amounting to a proposed FTV of £184.62m. 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 FTV of £160.3m. Table 2 below provides a breakdown of the cost categories for the Project at each stage and change between the ITV and the FTV.

[2] This included the £12.3m of offshore substation costs that we had reduced at the ITV stage

Table 2: Summary of cost categories

Category	Initial transfer value Feb-14 (£m)	ITV Mar-15 (£m)	FTV May-16 (£m)	Reasons for change between ITV and FTV
Capex	142.2	118.6	128.0	**<u>Includes increases of:</u> £3.1m for offshore substation commissioning £1.4m for Unexploded Ordnance clearance £1.1m for waiting on weather costs £1.9m for laying nearshore duct for subsea cable £2.0m for subsea cable storage and installation costs £0.7m for various minor costs £11.3m reallocation from development costs <u>Offset by decreases of:</u> £0.9m for land costs £11.2m for reductions to estimated costs[3]**
Development	16.2	27.4	14.3	**<u>Due to decreases of:</u> £11.3m for reallocating costs to capex £1.8m from reductions to estimated costs[4]**
Contingency	12.0	6.1	-	**Contingency in ITV was mostly used in addressing additional Capex and transaction costs.**
IDC	22.3	18.7	14.8	**IDC entitlement periods were reduced due to periods of project delay and reducing the initial entitlement period.**
Transaction	2	2.5	3.2	**Transaction costs have been added and are normally assessed at the end of the cost assessment process.**
Total	**194.7**	**173.3**	**160.3**	

2.15. The issues we have considered in setting the FTV are detailed below.

[3] Largely around subsea cable related costs and a reduced cost of expected claims
[4] Mostly staff/contractor costs and engineering & design costs

Capex

2.16. The Capex element of the FTV is £128.0m. Overall the Capex has increased by £9.4m since the ITV. As discussed in more detail below, the increase is largely due to increases in respect to laying the subsea cable and reallocations of costs from development. These cost increases were offset by reductions to estimated costs.

Accuracy and allocation of Capex costs

2.17. GT undertook a forensic investigation of the highest value Capex contracts. The Capex contracts investigated were:

- CG Power and Harland & Wolf – supply and installation of the offshore platform
- ABB and VSMC – supply and installation of the export cable
- Balfour Beatty – supply and install the onshore cable
- CG Power – installation of the onshore substation (including reactive)

2.18. 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 FTV.

2.19. In conducting our own analysis of these costs there was one substantive issue in respect of the land costs to be included in the FTV.

Onshore land

2.20. The Project's onshore substation is located at a site that was close to National Grid's (NGET) local system. The Developer decided to purchase the whole site of 8.49 acres, which is in excess of the project's requirements. The Developer's indicative cost submission included a cost of £2.6m for the entire land purchase costs (less the land costs for the Developer's control room).

2.21. At the ITV stage we noted that the land costs included the land to be leased to NGET. This was in excess of the requirements of the Project's transmission assets and was a cost that should not be included in the cost assessment. For this reason, we removed from the ITV the costs of both the Developer's unused land and the land rented to NGET. This resulted in a reduction of £1.2m from the ITV.

2.22. In considering the Developer's final cost submission, we became aware that the ownership of the land for the transmission assets will not transfer to the OFTO.

Ofgem's view

2.23. In light of the fact that the ownership of the land is not passing to the OFTO as part of the transfer arrangements, we do not think it appropriate that the acquisition cost of the land should be included in the FTV. However, we consider that the Developer can include costs for use of the land during construction of the transmission assets as part of the transfer value. Removing the land purchase cost but allowing an appropriate rate[5] for use of the land during construction results in a net deduction of £0.9m from the Developer's FTV submission.

2.24. The Developer will be able to charge an annual rental to the OFTO to reflect the cost of access to, and use of, the land being occupied by the transmission assets. This has been agreed on a commercial basis between the two parties.

Exchange rate movements

2.25. The majority of the major contracts in the project were in sterling and therefore there is no exchange rate impact. Some smaller contacts were in euros and the developer hedged for these.

Ofgem's view

2.26. We have reviewed the Developers hedging strategy for foreign exchange movements on the smaller contracts. This was done in line with our Guidance document and so we consider that this was done economically and efficiently.

Reallocations to Capex

2.27. When the Developer provided its final cost submission, development costs were estimated at £22.7m; this represents circa 14% of the Project's total cost submission. We were concerned by the level of these costs as they appeared well above what we have observed on other projects. Following review with the Developer, we agreed that some of the costs were more appropriately classified as Capex.

Ofgem's view

2.28. We have agreed with the Developer that £11.3m of the costs originally categorised as development costs are more correctly categorised as Capex, and we have reallocated them accordingly. For instance, costs for boulder clearance have been moved to the subsea cable cost category, and both land agent fees and entry payments have been reallocated to the land cable.

[5] We estimated this using land rental costs from a similar development in the area

Efficiency of Capex costs

2.29. The Developer's final cost submission included a number of increases in Capex costs. Some of these related to costs which had been disallowed at the ITV stage. There were also costs for additional construction activities.

Offshore Platform (OSP) related costs

2.30. At the ITV stage we made a reduction of £12.3m based on our assessment of the economic and efficient costs for the OSP. In particular, the installation costs were significantly in excess of levels seen for similar projects. The main reason for this increase was that the Developer had chosen a modular OSP design. The rationale was to eliminate the need for a heavy lift vessel and the associated high cost. The intention was that a smaller jack up vessel that was already chartered and on site would be used, reducing the installation cost.

2.31. However, the modular design of the OSP topside and jacket required the installation vessel to make multiple trips to site to complete the OSP installation. The additional trips involved significantly increased the OSP's costs beyond what a comparable project using a heavy lift vessel would have been expected to incur.

2.32. In its final cost submission the Developer re-submitted the £12.3m costs we had excluded and included an increase of £5.1m. This additional amount was to cover the costs of an accommodation vessel for the Project's commissioning team who worked on the OSP during the winter period.

2.33. The Developer explained that the use of this accommodation vessel was necessary to avoid project delays that could arise due to adverse weather conditions.

Ofgem's view

2.34. We asked the Developer for any new information to support the re-introduction of the OSP costs that were excluded from the ITV. We also asked for a justification of the further costs in relation to the jack-up vessel.

2.35. We revisited our benchmarking analysis and took into account the proposed increases. The analysis concluded that the OSP was a noticeable outlier when compared to other projects of a similar size and scale. We presented this analysis to the Developer who was unable to provide sufficient justification to support the inclusion of the costs that were removed at the ITV stage.

2.36. We consider that the high levels of costs are as a direct result of the Developer's design choice and do not align with what ought to have been incurred efficiently on the OSP. Consequently, we have removed the £12.3m costs that were previously excluded at the ITV stage.

2.37. We have reviewed the commissioning costs incurred by the Developer, along with its rationale for utilising a jack-up vessel. Our conclusion is that while it was a

rational response to the events, this level of costs is well in excess of what we would normally expect on a substation of this size and complexity. Again, this is as a result of the Developer's design choice and the knock-on effects on the commissioning schedule. We have reviewed our data on costs for both commissioned offshore substations and typical jack-up vessel costs, and concluded that the submitted costs were excessive. Consequently, we have only allowed £3.1m of the submitted £5.1m cost for the commissioning accommodation vessel, as we considered that this was a more appropriate level of cost for this activity.

Unexploded ordnance clearance

2.38. At the ITV stage the estimated costs for the unexploded ordnance (UXO) was £1.0m. As the project progressed, the actual costs went from estimated to firm. The developer included the final cost of £2.4m for the disposal of UXO in the cost of the submarine cable.

Ofgem's view

2.39. The final level of costs, and the allocation methodology between transmission and generation, were reviewed and are considered to be appropriate for this level of clearance. We have therefore allowed the extra £1.4m in the FTV.

Waiting on Weather costs

2.40. The installation of the export cable began on the 12th of October 2013 and was concluded on the 30th of November 2013. The Developer submitted a claim of £3.1m for associated waiting on weather costs.

2.41. The Developer explained that although its preferred installation start date was during the summer of 2013, it agreed with the cable installer to wait until it had completed its previous job. When the cable laying vessel arrived much later than originally expected, the Developer had the option to delay installation until the 2014 season. It decided to proceed in 2013 to avoid the risk of potential construction delays that may disrupt works programmed for 2014.

Ofgem's view

2.42. By choosing to reduce this potential future project risk, the likelihood of incurring substantial waiting on weather delays was increased significantly. This was backed up by studies made by MetOcean Data Systems (the Developers geotechnical consultant), which indicated that October, November and December were the worst months for installation in this area, in terms of weather and sea conditions.

2.43. Our analysis of the costs involved in the installation found that a total of 554 hours (equivalent to 23 days) of weather delays were incurred during this installation process. This is almost three times the level that would have been expected had the cable been installed during the earlier planned installation

window. Deferral of the cable laying period to beyond the actual period chosen would have expected to result in a similar reduction in the level of weather delays.

2.44. We have included £1.1m of the waiting on weather payments in the FTV. This value is a more likely level of what the Developer could have expected to incur if the cable had been laid during a more appropriate time window, ie post-Winter.

Subsea cable issues

2.45. The Developer's initial plan had been to use a plough to dig a trench for the cable along the nearshore area of the route. However, this area was subject to access restrictions during the summer months. In addition, the tidal flows created a number of access restrictions for cable laying barges which further limited the periods in which the cables could be laid. After further consideration, the Developer decided to alleviate these issues by extending the range of its near shore sub-surface ducts by a further 700m towards the sea. This relieved the access issues and allowed for a more flexible siting of the cable barge. The incremental cost associated with this revised plan was £1.9m.

2.46. The Developer incurred a number of unplanned costs during the subsea cable campaign. Firstly, the cable laying barge was not available to pick up the cable as planned, so the Developer was charged extra costs for storage until the cable was loaded onto the barge. In addition, installation costs were more than planned, in part due to the fact that the Developer had taken the option of choosing which contractor they were going to use to carry out the transition jointing after the cables were installed. This incurred an additional charge from the onshore cable contractor. The total of these unforeseen and additional costs was £2.0m.

Ofgem's view

2.47. We have included the £1.9m cost for the installation of sub-surface ducting in the FTV. The Developer took a prudent approach to the management of a number of interrelated risks which, had they materialised, could have resulted in far greater cost increases and significant delays to the Project.

2.48. We have also included the £2.0m cost of dealing with cable delay/jointing issues in the FTV. The Developer had planned for the cable to be manufactured ahead of the scheduled vessel availability in order to avoid the scenario where the vessel is waiting for the cable, since vessel waiting costs are significantly greater than cable storage costs. The additional storage costs for the cable were largely unavoidable, being the result of a constrained market for cable laying vessels and are not reasonably controllable by the Developer. Similarly, the additional jointing costs were recognised at the start of the project, but were an additional cost from the ITV stage that we have allowed.

Various Minor Costs

2.49. In the time between the submission of the cost template for the ITV and that for the FTV, there have been a large number of changes to costs. This report highlights the main movements, but there were a large number of small changes, such as variation orders, which increased capex by £0.7m.

Ofgem's view

2.50. While we have not reviewed all of these changes in detail, we are content that they are representative of the variations that occur between ITV and FTV, and so we have included them in the assessed cost.

Development costs

2.51. The assessed development expenditure for the HG transmission assets is £14.3m. These are costs incurred by the Developer outside the scope of the main construction contracts.

2.52. For the purpose of informing our cost assessment, we reviewed the cost information provided by the Developer in connection with developing the Project. We also asked our advisors to investigate the Project's development costs.

Accuracy and allocation of development costs

Reallocations to Capex

2.53. Following review of the Developer's submission, we agreed that some costs were more appropriately classified as capex. This resulted in the reallocation of £11.3m for Development costs to the capex cost category. See paragraph [2.27] above for further details.

Efficiency of Development Costs

2.54. The overall level of development costs (following reallocation) is just over 9% of the FTV. This is in keeping with the levels seen in other offshore projects and so we consider efficient.

Contingency

2.55. The assessed costs do not contain a separate contingency value. £6.1m of the contingency that existed at the ITV stage has primarily been utilised to deal with unforeseen capex costs. The remaining was removed by the Developer from its final cost submission.

Interest during construction

2.56. The Developer's proposed IDC was £19.6m. This is based on the Developer's calculation of the IDC to completion of the assets over a period from February 2005 to January 2015. The changes from the ITV are as a result of a review of the initial Capex at the beginning of the project and adjustments to the IDC periods due to delays on the project.

2.57. We reviewed the Developer's IDC submission which has resulted in a number of changes. The net impact of these changes was a £4.8m reduction to the Developer's IDC claim. The total IDC for the HG transmission assets after reductions is £14.8m.

Accuracy and allocation of IDC

IDC rates used

2.58. The Project incurred Capex from early 2005 to January 2015. Three different IDC rates have been applied across the period of the Project:

- 10.8% from February 2005 until November 2011;
- 8.5% from December 2011 until March 2014; and
- 8% from April 2014 to January 2015.

Ofgem's view

2.59. We have concluded that the IDC rates used by the Developer were correct for the relevant portions of the project.

Efficiency of IDC

Initial spend profile

2.60. A review of the spend profile showed that over the first six years there was very little investment (~£2.1m) but that because the Developer was receiving the highest rate of IDC, the interest payments had reached almost half (£923K) of the investment amount. The Developer took 81 months before making its Financial Investment Decision (FID) for the project.

Ofgem's view

2.61. The capex spent up to the point of FID is largely speculative in nature, as up to that point, the project has no certainty. IDC is meant to remunerate Developers for funding an active ongoing project, rather than incentivising a developer to benefit from an advantageous locked-in IDC rate. Therefore, we do not consider it appropriate that the pre-FID investment should be remunerated to the extent that the Developer has claimed.

2.62. The HG Project achieved FID within a couple of months that it reached the 5% project spend level. We have reviewed our data on the times taken by other developers during the previous 14 offshore transmission projects to achieve a similar spend level. We have concluded that 30 months is a more appropriate time to reach 5% spend on this project. Consequently, we have scaled back the IDC over each of the first 83 months by 30/83, and this has reduced the Developer's IDC claim by £1.2m.

Project delays

2.63. The project encountered a number of delays with key components. The OSP installation experienced a significant delay, but notwithstanding this delay, the Developer took the decision to install the subsea cable in 2013 and laid it down on the seabed until the OSP was in place.

Ofgem's view

2.64. The Tender Regulations require us to make "...an assessment of the costs which ought to have been incurred in connection with the development and construction of those transmission assets". The Offshore Transmission: Guidance for Cost Assessment (and prior cost assessment reports) states that if we consider that there is evidence of inefficient and uneconomic delays during the construction or commissioning programme for the transmission assets, the period of IDC applicability may be curtailed to reflect this.

2.65. For the OSP, it is clear to us that there were construction delays which meant that the top side was sitting dormant for a considerable time. We have made allowances for the fact that in a normal construction timeline, there will be some periods where major assets of this type will be dormant either due to bad weather or while waiting for other interacting elements to be in place. Accordingly, we have reduced IDC on this component for 4 months of the 12 that it lay dormant. This has reduced the Developer's IDC entitlement by £0.6m.

2.66. In assessing the efficiency of the subsea cable, it is with reference to what an efficient transmission operator would be expected to do in the same circumstances. We recognise that from a generation perspective, it may have been a suitably risk averse action to install the cable a year or more in advance of need, but from a transmission perspective, we do not consider that generator risk is part of efficient costs. Therefore we have suspended the IDC for the period while the cable was laid down, which has reduced the IDC by £2.0m.

Capex reductions

2.67. The Developer submitted a cost template with a project spend of £164.9m. This included £12.3m of costs relating to the OSP which Ofgem has excluded from the ITV. After our review of costs, the efficient project spend is deemed to be £145.5m. The effect of the reductions in spend being fed through the cashflow is a further reduction of £1.0m from the Developer's IDC submission.

Transaction costs

2.68. The ITV included an estimate of £2.5m for transaction costs. The Developer has subsequently submitted a firm estimate of the costs it expects to incur to asset transfer as being £3.0m.

Accuracy and allocation of transaction costs

2.69. The developer provided information regarding both internal and external costs. For their internal costs they provided information on the personnel who were involved and their day rate relating to the work undertaken and time spent on the tender process as opposed to the construction of the project or generation activities. The external costs related to professional services in respect of the tender, eg legal, accountancy and technical. We have concluded that the costs provided by the developer were allocated appropriately.

Efficiency of transaction costs

2.70. Transaction costs can only be provided to us by the developers to a reasonable degree of accuracy towards the end of the tender process. We have analysed and considered the types of resource costs incurred in relation to this tender process and these transaction costs appear economic and efficient on the basis that this is in line with the transaction cost element of other similar offshore projects.

Confirmations in relation to tax benefits

2.71. The ITV was calculated on the basis that the OFTO would obtain the full benefit of all available capital allowances. For the FTV, the Developer has confirmed that the OFTO will be able to obtain the full benefit of all available capital allowances and therefore the FTV will be the same as the assessed 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 HG transmission assets is £160,297,985.

Appendices

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GT

Grant Thornton

I

IDC

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ITT

Invitation to Tender

ITV
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MW

Megawatt

O

OFTO

Offshore Transmission Owner

P

Project

The development and construction of the HG offshore transmission assets

Q

QTT

Qualification to Tender