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Offshore Transmission: Cost assessment for the Lincs transmission assets

Decision

Publication date:
4 November 2014

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Overview:

This document sets out our cost assessment for the Lincs transmission assets and the key principles that we have applied in our cost assessment process for the second transitional tender round. The Authority has used the assessment of costs to determine the value of the Lincs transmission assets. The Authority has granted an offshore transmission licence to TC Lincs OFTO Limited, incorporated by the consortium of Transmission Capital Partners Limited Partnership and International Public Partnerships Limited.

TC Lincs OFTO Limited has incorporated the assessed transfer value as set out in this report into their tender revenue stream. The appendices published alongside this report are available on the Ofgem website. They include correspondence between Ofgem and the developer as part of the cost assessment process and external consultants' reports referred to in this document.

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 transitional tender regime has been designed for projects that were under development, in construction or constructed at the time of the announcement of the regime[1].

The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2010 (the Tender Regulations") provide the legal framework for the process which Ofgem run for the grant of offshore electricity transmission licences and apply to tender exercises that met the qualifying project requirements set out in the Tender Regulations by 31 March 2012. The Electricity (Competitive Tenders for Offshore Transmission Licence) Regulations 2013 ("the 2013 Tender Regulations") came into force on 22 February 2013. The 2013 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 apply to the Lincs 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.

This is the tenth cost assessment report for offshore transmission published by Ofgem, and the second relating to the second transitional tender round.

Associated documents

- Kema report on benchmarking Link
- Ernst and Young report on Interest During Construction Link
- The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2010 Link
- Offshore Transmission: Tender Rules Link

[1] http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/Main.pdf

- Interest During Construction for Transitional Tender Rounds Link
- Offshore Transmission: Guidance for Cost Assessment Link

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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 Lincs 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 initial estimate was £310.5m ("the initial transfer value"). This was communicated to the Developer and published in the preliminary information memorandum (PIM) in November 2010.

- The indicative estimate of costs was £281.6m ("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 July 2011. The indicative transfer value was published in the project information memorandum (IM) and was the transfer value assumed for the purpose of Invitation To Tender (ITT) stage submissions.

- The assessment of costs is £307.7m ("the assessed costs"). This compares to the Developer's final submission of £335.2m, a reduction of £27.5m. Part of this reduction is due to inefficiencies by the developer. 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. This is also 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 (together with the Developer's submission of the latter) values are given in table 1 below, followed by a summary of the reasons for movements between the indicative and the final transfer value.

Table 1: Summary of cost components

Category	Initial Transfer Value Nov 2010 (£m)	Indicative Transfer Value Jul 2011 (£m)	Developers Proposed Transfer Value 2013 (£m)	Final Transfer Value Dec 2013 (£m)
Capex	210.7	206.8	246.5	234.4
Development	18.2	18.1	40.9	35.6
Contingency	43.8	22.4	0	0
IDC	37.8	34.3	45.1	35.0
Transaction	0	0	2.7	2.7
Total	**310.5**	**281.6**	**335.2**	**307.7**

Capital expenditure (Capex)

The Capex component of the final transfer value increased by £27.6m since the indicative transfer value. This includes increases of:

- £14.8m for export cable supply and installation costs;
- £8m for onshore substation costs;
- £5.7m for nearshore consents costs;
- £1.5m for cable remedial works; and
- £0.6m for onshore and offshore spares.

These increases were offset by a number of reductions:

- £1.8m reduction for offshore substation costs;
- £1m for offshore boundary changes between generation and transmission;
- £0.1m for land cable costs; and
- £0.1m for onshore connection contract changes.

Development costs

The Project's development costs have increased by £17.5m to £35.6m since the indicative transfer value. The increase relates mainly to project management costs for sourcing and managing additional contractors to carry out the nearshore cable laying operations.

Contingency

The entire contingency allowed in the indicative transfer value has been used in addressing additional Capex costs.

Interest during construction (IDC)

The IDC amount has increased by £0.7m as a result of extended Project duration and an increase in the Project's Capex and development costs.

Transaction costs

The transaction costs are composed of both internal and external resource costs arising from the Developer's participation in the tender process. The transaction costs have been assessed to be £2.7m.

Capital Allowances

The Developer has confirmed that the incoming OFTO will be able to obtain the full benefit of all available capital allowances.

Final transfer value for the Lincs transmission assets

In accordance with Regulation 4(2)(b) of the Tender Regulations, the assessed costs of the Lincs transmission assets are £307,728,310.36. The final transfer value as determined by the Authority under Regulation 4(6) of the Tender Regulations is £307,728,310.36.

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 projects in the transitional tender rounds and the reasoning for such principles can be found in the document 'Offshore Transmission: Guidance for Cost Assessment'[2] (hereafter "the Guidance").

1.4. We intend to apply these principles in our cost assessment process for all projects in the transitional tender rounds. However, we may need to review them where appropriate in light of the analysis undertaken in respect of project specific circumstances.

[2] 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 developers in the form of cost reporting templates, contract values, asset cost schedules and cash flows. Developers also provide supporting evidence to substantiate their cost submissions including, amongst other things, contract documentation, supplier payment lists, bank statements, invoices and receipts.

1.7. The data collection to inform the cost assessment process for all projects in the transitional tender rounds commenced in December 2008 and continues to date. Throughout this period we have worked closely with developers, gathering 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) stage of the tender process. The letter we send to developers 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 indicative transfer value for the commencement of the 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 developers confirming the indicative transfer value indicates that the calculation might be updated as a result of any further information provided by the developers and our continuing analysis. For all

projects other than Barrow, this letter provides comfort (subject to certain matters) that the minimum transfer value the developer will receive for the transmission assets once their project is complete is 75% of the indicative transfer value.

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 modification 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 conclusion of the section 8A consultation and the Authority has determined to grant an offshore transmission licence to the successful bidder.

Final transfer value

1.15. The assessed costs are used by the Authority to determine the final transfer value, which 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 final transfer value.

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 developers 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 developers provide cost information to us on an ongoing basis. Where we identify discrepancies in how the developer has allocated these costs we check with developers 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 developers. 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 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 other projects in the transitional 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 the cost estimate exercise to derive the indicative transfer value we undertake a benchmarking exercise using comparable costs across all projects in the transitional tender rounds to identify any cost outliers across the main cost categories. Any cost outliers we identify through the benchmarking exercise are subject to further review. This exercise examines individual cost categories including:

- total cost of transmission assets as a percentage of overall project cost;
- total cost of transmission assets per MW kilometre;
- cost of offshore substation per MW;
- cost of offshore substation (platform and electrical) per installed MW;
- cost of submarine cable supply and installation per kilometre;
- cost of transformer per MVA;
- cost of reactive equipment per kilometre of cable; and
- development cost as a percentage of transmission assets.

1.24. This benchmarking exercise informs our communication to the developer in our letter which sets out the indicative transfer value.

1.25. We also consider the procurement processes adopted by the developer to obtain economic and efficient transmission asset costs. We note the differing procurement approaches taken by developers for projects in the transitional tender rounds. We will keep the efficiency of developer procurement and contract management approaches under close review for future cost assessments.

1.26. When undertaking the assessment of costs to derive the final transfer value, where Capex or development costs have increased since the indicative transfer value, developers are asked to provide supporting documentation to justify these increases. Depending on the nature of the increase, we may undertake a technical investigation which focuses on, for example, a particular cost increase in a contract or multiple increases across several contracts.

2. Lincs Cost Assessment

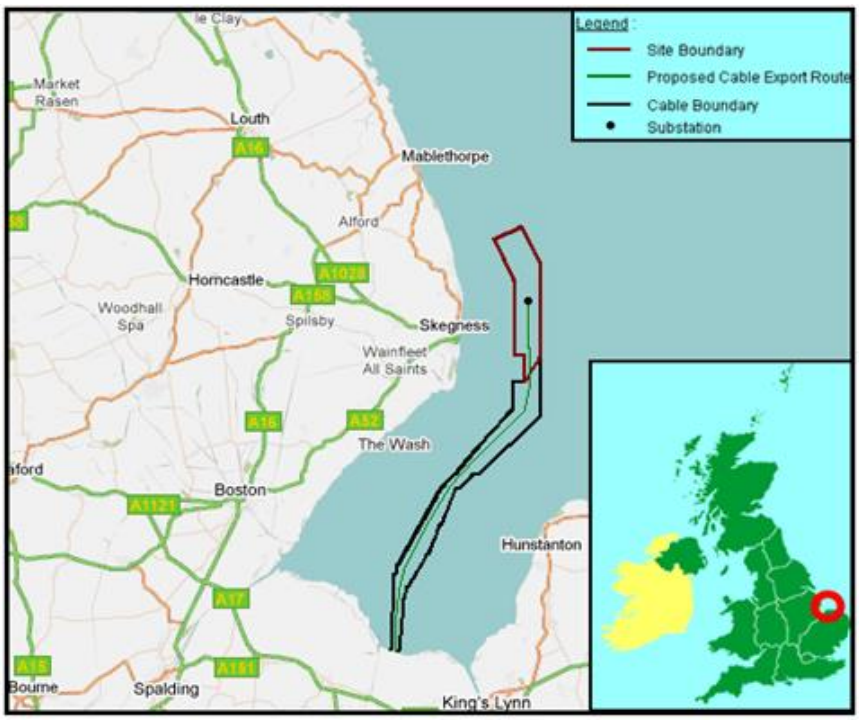
Chapter Summary

This chapter summarises how we have undertaken our cost assessment for the Lincs transmission assets from the initial transfer value to the final transfer value, with an emphasis on the difference between the indicative and final transfer value. It provides a breakdown of the key cost categories that we have considered and highlights the decisions that we have made.

Lincs Transmission Assets

2.1. The Lincs Wind Farm is located approximately 8km off the coast of Lincolnshire near to Skegness in East England, as illustrated in Figure 1 below. The Lincs Wind Farm consists of 75 wind turbine generators of 3.6MW, with an installed capacity of 270MW. The Lincs transmission assets became operational in July 2012.

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



Source: Independant Lender's' Engineer's Report, Lenders' Technical Adviser 2010

2.2. Lincs Wind Farm Limited ("the Developer") is a joint venture between three companies, Centrica Renewable Energy Ltd (50%), Dong Energy (Lincs) UK Ltd (25%) and Siemens Project Ventures GmbH (25%).

2.3. The Lincs transmission assets connect to the Lincs Wind Farm at an offshore platform. The transmission assets that are transferring to the OFTO comprise of:

- one offshore platform and associated substation;
- two 132kV subsea export cables, each approximately 48km in length;
- two 132kV onshore cables, each approximately 12km in length; and
- one onshore substation at Walpole.

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

- Offshore: Located at the offshore substation 33kV Gas Insulated Switchgear (GIS); and
- Onshore: Located at the point where the 400kV GIS busbars in Walpole will terminate at the disconnectors of the circuit breaker bays owned by National Grid Electricity Transmission (NGET).

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

- Offshore and onshore substation strategic spares from the electrical contractor;
- Lengths of 630mm and 1000m spare cables and sections of 132kV cables;
- Various cable joints (630mm, 630-1000mm and 1000mm size joints);
- Export cable seals and consumables; and
- Associated miscellaneous spares.

Lincs cost assessment process overview

2.6. Since September 2010, 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.

- September 2010: Developer Information Request (DIR) sent to the Developer.
- October 2010: Developer submitted DIR.
- October - November 2010: Ofgem analysis of the Developer information and benchmarking.
- November 2010: Initial Transfer Value (£310.5m) published.
- November 2010 - July 2011: Further information received from the Developer and analysed by Ofgem.

- July 2011: Indicative Transfer Value (£281.6m) published.
- November 2011 - May 2013: Cost reporting updates performed with the Developer over the course of construction of the Project.
- December 2011 – May 2012: Technical investigation of onshore substation costs.
- December 2012 - April 2013: Forensic and technical investigations undertaken.
- May 2013 - July 2013: Closure on issues raised by forensic and technical consultants.
- December 2013: Draft cost assessment report released to the Developer for comment and the preferred bidder for information.
- September 2014: Draft cost assessment report published alongside the section 8A consultation.
- November 2014: 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 November 2010 was £310.5m. 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 indicative transfer value of £281.6m was established in July 2011, comprising estimated Capex, development and contingency costs of £247.3m and IDC of £34.3m. The difference from the initial transfer value was due to cost changes arising from our estimate of the accuracy and allocation of the Developer's cost submissions, and estimating whether the Developer's costs were economic and efficient. Our estimate was supported by our forensic accounting advisor, Grant Thornton ("GT"), and our technical advisor Noble Denton.

Process for determining the assessed costs

Accuracy and Allocation

2.9. 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.

2.10. This investigation considered the main contracts in respect of the transmission assets for the following: (1) the export cable supply; (2) the export cable installation; and

(3) the onshore and offshore substations. In addition to the contract analysis we asked GT to conduct a review of the project management costs.

2.11. We also checked that the costs were allocated to the correct asset category and that they had been allocated correctly 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
- cash flow payments related to the transmission assets.

Efficiency

2.12. After costs had been appropriately identified and allocated, we performed an assessment of whether these costs had been incurred economically and efficiently. We took into consideration the following:

- the findings of the forensic accounting investigations by GT (appendices 5 and 6); and
- the findings of technical investigations by Noble Denton, Kema and Tractebel Engineering (appendices 4, 7 and 8 respectively).

Summary of assessment

2.13. Following completion of the construction and development of the transmission assets, the Developer submitted costs amounting to a proposed final transfer value of £335.2m. The 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 £307.7m. Table 2 below provides a breakdown of the cost categories for the Project at each stage and the reasons for change between the indicative transfer value and the final transfer value.

Table 2: Summary of cost categories

Category	Initial Transfer Value: Nov 2010 (£m)	Indicative Transfer Value: Jul 2011 (£m)	Final Transfer Value: Dec 2013 (£m)	Reasons for change between Indicative Transfer Value and Final Transfer Value
Capex	210.7	206.8	234.4	Includes increases of: £14.8m for cable supply and installation (covers 2010 ,2011 & 2012 nearshore campaign, cable plough incident, vessel costs & jointing works) £8m for onshore substation £5.7m for nearshore consents costs £1.5m for cable remedial works £0.6m for onshore and offshore spares Offset by decreases of: £1.8m for the offshore substation costs £1m for offshore boundary change £0.2m for other cost reductions
Development	18.2	18.1	35.6	Increase of: £17.5m in project management costs due to increased Project duration and managing multiple contractors
Contingency	43.8	22.4	0	Contingency in the indicative transfer value was used in addressing additional cable supply and installation Capex costs.
IDC	37.8	34.3	35.0	IDC increased as result of a longer construction period and an increase in Capex costs
Transaction	0.0	0.0	2.7	Transaction costs have been added, which are assessed at the end of the cost assessment process
Total	**310.5**	**281.6**	**307.7**	

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

Capex

2.15. The Capex element of the final transfer value is £234.4m. Overall the Capex has increased by £23.7m from the initial transfer value to the final transfer value. The majority of the Capex increase is related to the Project's cable installation process.

2.16. Table 3 below provides an overview of the Capex costs submitted by the Developer for the purpose of the final transfer value and the Capex costs allowed in the final transfer value.

Accuracy and allocation of Capex costs

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

- Nexans Norway AS (Nexans) – export and onshore cable supply;
- Siemens Transmission and Distribution Limited (Siemens) – onshore and offshore substations; and
- Technip – export cable installation.

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. Where costs were shared between generation and transmission assets, the Developer allocated the percentage to the transmission assets using cost drivers, which differ depending on the nature of the work undertaken. Only those costs related to the transmission assets were allowed in the indicative and final transfer values.

2.19. In conducting our own analysis of these costs there were a number of items that were identified which we have discussed with the Developer. These items are set out below.

Change of boundary point

2.20. The invoices paid by the Developer to Siemens originally included the sum of £1.0m for 33kV switchgear which the Developer anticipated would form part of the transmission assets. As a result of a boundary point change, the 33kV switchgear forms part of the generation assets and the Developer reduced the size of the submitted transfer value accordingly.

Ofgem's view

2.21. We agree that the Developer was correct to remove the costs from their submission as a result of the boundary point change.

Exchange rate movements

2.22. The contract for the supply of the export cable by Nexans was exposed to foreign exchange risk for 470m Norwegian Kroner. The exchange rate altered between the time of entering the contract with Nexans and the time when payments were made under the contract.

2.23. The Developer managed the exposure to foreign exchange movements through forward exchange contracts. The use of forward exchange contracts is consistent with the Guidance in respect of hedging for foreign currency movements.

2.24. The Developer adjusted their final cost submission for any foreign exchange gains or losses on their contract, as noted by GT in their report.

Ofgem's view

2.25. We agree that it was appropriate for the Developer to make this adjustment.

Efficiency of Capex costs

2.26. The Developer submitted increased Capex costs associated with the Project's cable installation process, the onshore substation, the acquisition of spares and obtaining consents. For the purposes of informing our assessment of the efficiency of the Capex costs, our technical adviser, Tractebel, investigated the cost increases related to the Project's nearshore cable installation, while Kema examined the onshore substation cost increases. We also undertook further investigations to gain a better understanding of the issues to inform our views on whether the increases proposed by the Developer were economic and efficient. We have detailed below the main issues that were considered and how we have assessed these costs.

Export cable installation: 2010 campaign - Horizontal Directional Drilling (HDD)

2.27. The Project's export cable route is through the Wash. Cable installation in the nearshore is across long inter-tidal areas and a salt marsh. The route passes through a number of conservation and environmentally sensitive sites and the Developer faced strict consenting arrangements including a tight timeframe for undertaking nearshore cable works. The consenting body (Natural England) insisted that the Developer should use Horizontal Directional Drilling (HDD) to lay the nearshore cable. The Developer was granted a consent window to undertake works from 15 May 2010 to 31 August 2010.

2.28. The Developer contracted with Subocean Limited for a number of work packages, one of which involved sea defence and salt marsh ducts to be installed by HDD. The HDD landfall campaign began in June 2010 but was halted after the drill became stuck. Subsequent attempts to complete HDD failed due to drill holes collapsing. It was decided to abandon the HDD methodology after six attempts, as a stable drill hole could not be established by the time that the consent window expired. At the time of this decision the Developer had committed £10m of expenditure to the 2010 HDD campaign. In January 2011 Subocean Limited went into administration and the Developer was forced to seek alternative contractors to progress the nearshore works.

Tractebel's conclusions

2.29. Tractebel investigated these matters further to gain a better understanding of the issues and to inform our views on whether the costs proposed by the Developer were economic and efficient. They considered that HDD was not a suitable means of installing the cable in the nearshore area, given the challenging environmental

conditions and the absence of a detailed local site conditions assessment. Accordingly, Tractebel's view is that the installation difficulties experienced during the 2010 HDD campaign should have been anticipated by the Developer and therefore planned for. In addition, they conclude that insufficient pre-installation risk assessment and mitigation procedures were in place prior to the commencement of the cable installation works. Consequently, Tractebel suggested that £10m of the nearshore cable costs incurred in the 2010 HDD campaign which did not achieve any of its proposed objectives should be removed from the Developer's submission.

Ofgem's view

2.30. The Developer provided us with a detailed overview of the nearshore cable installation process. We also asked for clarity on the consenting arrangements that were imposed on the Project and the rationale for the chosen connection point. The analysis provided by the Developer suggested that the decision to lay cables through the Wash was informed by technical studies which considered, in particular, the National Grid connection options. We note that the consenting arrangements with Natural England at that time precluded alternatives to HDD and that a tight window to complete the HDD works was also stipulated.

2.31. We note that the failure of the HDD works was directly attributable to the sensitive site and soil conditions. However, due to consenting restrictions, the Developer was unable to examine in detail the site and soil conditions in the nearshore area. As such, the consenting conditions forced the Developer into performing a difficult procedure with insufficient knowledge of the prospects of success. The failed campaign had a 'knock-on effect' on the Project and led to increased costs and delays to the Project's cable installation campaign.

2.32. Given the significant uncertainty around the HDD process as applied in this instance, we asked to review the Developer's risk management for the HDD campaign. The Developer was not able to provide any evidence that they had carried out a risk assessment for the HDD campaign, nor was it able to provide evidence of any mitigation plans if it became clear that HDD was encountering difficulties.

2.33. We acknowledge that the Developer was obliged to proceed with HDD under difficult circumstances, and that it would have incurred significant costs even if it had stopped the process early in the consenting window. Therefore, we consider that it would be disproportionate to exclude all of the 2010 HDD campaign costs. However, we believe that it is not appropriate for consumers to bear all the cost overruns. Project risks should sit with those best placed to manage them; and only efficient costs for doing so should be remunerated. In this case a proportion of the Project's failed HDD costs should be the Developer's responsibility. The lack of appropriate risk mitigation and planning has increased Project costs for no discernible gain, and it would be inappropriate to consider the full amount as economic and efficient. On balance we have decided to remove £3m from the Developer's submission of £10m.

<u>Export cable installation: 2011 campaign - use of rollers</u>

2.34. After the failed 2010 HDD campaign and as a result of Subocean Limited going into administration, the Developer was forced to seek additional consents and source alternative contractors. This involved a multi contract approach, with the development of a revised installation methodology in the nearshore area and additional consents being sought. The alternative methodology was developed in conjunction with a third party contractor at a cost of £5.7m. The cable installation method employed chain trenching involving the use of rollers provided by third party contractors with an all terrain vehicle that was designed to navigate the nearshore area. The nearshore campaign trials began in May 2011 and it was decided to use rollers to facilitate unloading the cable into position.

2.35. The cable trenching vehicle became stuck when it was offloaded from a support vessel as the ground conditions were much softer than anticipated. This led to further delays. When works recommenced, cable tensioning issues resulted in a tightened cable loop developing in the cable's armour wires. The damaged section of cable was cut and a new cable end was prepared for landing the cable. Works were stalled as the Developer considered whether to continue using rollers.

2.36. The Developer decided to abandon the use of rollers as the ground conditions were very soft and the chosen roller spacing made the deployment of rollers difficult and time consuming. It was decided to float the cable in and another contractor was appointed to do so. The nearshore installation commenced again in July 2011 and during operations the trenching vehicle again became stuck in soft ground conditions.

2.37. The Developer obtained an extension to the consent window and was able to complete laying the first export cable in September 2011, using the revised methodology of floating in the cable.

Tractebel's conclusions

2.38. Tractebel's view is that given the knowledge of the surface conditions gained from the previous season's work, it should have been clear that it was unlikely that rollers would have succeeded in that terrain. They also noted that the rollers were not employed in line with the manufacturer's recommendation, in particular, they were too spaced out and so did not offer sufficient support to the cable while it was being unloaded. This lack of support was a contributory factor to the formation of the cable loop and the associated extra costs. In response to Tractebel's view that the Developer should have considered the float-in method from the start of the 2011 campaign, the Developer has stated that the tidal conditions were not suitable for this method early on in the 2011 consent window and it was estimated that there would be insufficient water along the cable route. Tractebel concluded that the float in method was prematurely abandoned. Tractebel notes that the mean high water level was indicated on drawings that it reviewed, therefore, the tidal conditions were acceptable during the consent window.

Ofgem's view

2.39. We note that the Developer was operating under a tight timeframe to source contractors and implement an alternative installation methodology for 2011, while still restricted to a short construction consent window. However, the evidence provided to us suggests that insufficient planning took place for the 2011 campaign, and lessons were not learnt from the 2010 campaign. We note in particular that there appears to have been limited preparatory evaluation of the roller set up, and in particular, no robust justification for the spacing that was applied in contradiction of supplier recommendations. We note our consultant's position regarding the Developer's claim that the tidal conditions were insufficient for use of the float-in method at the early stage, since it appears to have been successfully employed at that period in the following year's campaign. The decision to deploy rollers increased costs for no discernable gain, in circumstances where the Developer had experience of the difficulties likely to arise given the failed 2010 campaign. We have therefore decided to reduce the Developer's submission by £800k which represents the costs of sourcing the rollers. We have allowed costs of £5.6m for undertaking the nearshore works.

Export cable installation: 2012 campaign - contractor mobilisation and demobilisation costs

2.40. Due to the difficulties encountered during 2010 and 2011, the Developer had only completed the installation of one export cable by the end of 2011. To complete the second cable installation in 2012 required new consents, additional contractors, and amendments to extend contracts that were already in place. The second cable was laid using the float-in method in the 2012 season, without any major incident.

Tractebel's conclusions

2.41. Tractebel concluded that the 2012 costs could have been avoided if the appropriate installation methodology was adopted at the outset during the 2011 campaign, as there would then have been sufficient time to lay both cables. Accordingly, it recommended disallowing all £6.7m of the 2012 campaign costs. Tractebel noted that the 2012 campaign which utilised the cable float in methodology was completed with minimal problems.

Ofgem's view

2.42. We are concerned that the Developer took three seasons to lay two export cables. We recognise that cable installation is an area of difficulty and a number of projects in the transitional tender rounds have experienced construction overruns and delays in this respect. However, we have to consider in all cases whether it is appropriate for consumers to bear all of the risks associated with offshore construction. In this case, the length of time taken to lay the Project's cables in the nearshore is much longer that we have seen on other comparable projects in the transitional tender rounds. Whilst we recognise the difficulties that the Project faced, we consider that the Developer should bear a proportion of the cost overruns that were experienced. We have concluded that three seasons is an inefficient length of time taken by the Developer to install the two cables and consequently we have decided that the

avoidable cost of the Project's 2012 contractor mobilisation and demobilisation costs should not be included in the assessed costs. This represents a reduction of £2m from the Developer's submission of £6.7m.

Export cable installation: plough incident/jointing works

2.43. The Developer faced additional costs arising from incidents that took place during the main export cable installation. These works were undertaken by Technip who were appointed after Subocean Limited went into administration. When offloading the cables from the quay in Norway they were observed to be damaged as a result of factory testing and required repairs. This led to delays to the main export cable installation process and increases in vessel costs.

2.44. When cable installation works restarted, the cable was damaged by a plough (at KP 18) and a section was cut which required a field joint. This led to delays to the main cable installation process, increased jointing and vessel costs. The plough incident jointing works were part of a campaign undertaken by the Developer for various sections of the export cable and involved a number of contractors. The total costs submitted, including vessel costs, were £8.2m.

Ofgem's view

2.45. We requested information from the Developer to substantiate the costs that were incurred. We also asked for clarity on the decisions and actions that were taken at the time. We have concluded that the incidents that took place were outside the Developer's control. The evidence presented to us, suggests that the Developer took reasonable and prudent steps to minimise the arising costs and delays to the Project, for example, a number of insurance claims were made. On this basis we have concluded that the additional costs of £8.2m should be included in the assessed costs.

Export cable installation: Insurance claims

2.46. In the course of the cable laying process four incidents occurred which resulted in insurance claims being raised. The total materiality of the insurance claims was £11.6m, of which the four claims had deductibles of £500k per event, totalling £2m and the insurers paid out a total of £6.1m. The remaining amount of £3.5m was disputed by the insurers and not paid to the Developer. The Developer included this difference in its final Capex cost submission.

Ofgem's view

2.47. In line with our Guidance, we have accepted the claims for insurance premiums and deductibles in the assessed costs. It is the Developer's responsibility to ensure that it gets appropriate recompense from the insurer, so we have concluded not to include the £3.5m in dispute with the insurer in the assessed costs.

Export cable installation: Nearshore consent costs

2.48. The Project's original consent requirement was to use HDD to install ducts for the cable landfall with a consent window from 15 May 2010 to 31 August 2010. Following the failure of the 2010 HDD campaign, the Developer investigated other options for landfalling the export cables. This involved seeking extensions and where appropriate new consents for the revised installation methodology. The Developer engaged in discussions with Natural England and various other agencies including the Maritime Marine Operator and the Local Planning Authority in respect of the saltmarsh and inter-tidal area. Revising and obtaining the necessary consents for the 2011 and 2012 cable installation was a costly and resource intensive process. The Developer's proposed cost increase was £5.7m.

Tractebel's conclusions

2.49. Tracetebel's report notes that the Project faced strict consent arrangements especially in the 1 km long saltmarsh area (which is environmentally sensitive). For example, minimal disturbance to animal life, minimum impact on creeks and gullies and restrictions on the use of machinery and personnel passage. Tractebel noted that the original consent obtained by the Developer only permitted the use of HDD to cross the saltmarsh and the sea defences. They concluded that the Developer should have challenged the restrictive nature of the original consents and noted that the Developer eventually obtained consents for the revised installation methodologies after the HDD campaign failed.

Ofgem's views

2.50. We requested information from the Developer to substantiate the cost increases. We also asked for clarity on the decisions and actions that were taken at the time. We note that the Developer faced strict consenting arrangements which imposed a HDD solution. Following the failure of the HDD campaign the Developer had to formulate and implement a revised cable installation methodology for the nearshore. To carry this out, the Developer required amendments to existing consents and new consents to carry out additional works which were obtained at short notice to enable works to be progressed during the planning consent windows for 2010 to 2012.

2.51. We conclude that the Developer was faced with no alternative but to obtain the necessary consents to minimise delays to the Project's construction. The evidence presented to us suggests that the Developer took reasonable and prudent steps to minimise the additional costs and delays to the Project. On this basis we have concluded that the additional consenting costs of £5.7m should be included in the assessed costs.

Export cable installation: Cable remedial works

2.52. The Developer faces additional costs for undertaking post cable installation remedial works to protect joints and sections of the cable that require additional protection

and in some cases remains unburied. The Developer set aside a provisional sum for these works which involves rock placement, mattressing, gabion bagging and associated vessel/port costs. The Developer's initial estimate was less than the actual scope and costs for these works. The net increase proposed was £1.5m.

Ofgem's view

2.53. We requested information from the Developer to substantiate this increase. The Developer provided detail regarding the events that led to the works, the intended scope of the works and procurement information. We note that the need for the works is due to matters outside the control of the Developer and that under their contractual arrangements, the Developer is obliged to meet these costs. Under the circumstances and based on the information presented, we consider that the Developer has acted prudently and has sought to minimise costs in this respect. We consider that the Developer has managed this situation in an appropriate manner, such that the associated costs have been economically and efficiently incurred. We have therefore allowed £1.5m in the assessed costs.

Onshore Substation Gas Insulated Switchgear (GIS) and Transformer Costs

2.54. Our technical advisors at the indicative transfer value stage, Noble Denton, considered that the acquisition costs for the onshore substation's transformer and associated GIS were excessive. Following further analysis, we removed £12m from the onshore substation element of the Developer's cost submission of £51.5m. At the request of the Developer, additional work was undertaken to consider the Developer's supporting evidence. We employed Kema to carry out this further review.

Kema's conclusions

2.55. In conducting this analysis, Kema engaged closely with Centrica, the Project's lead developer to understand, amongst other things, the Project's design and technical issues, including verification of assets, equipment configuration, transformer selection and the procurement approach for major cost items.

2.56. Kema conducted a further bottom-up review of the costs for the onshore transformer and GIS, as well as scrutinising how the Developer's procurement policies had been applied in this instance. By considering the levels of cost uncertainty around the transformer elements, it concluded that the contracts for the originally specified transformer with air-insulated switchgear had been procured efficiently. However, it considered that the Developer had incurred excessive payments when the design had been changed over to GIS. Kema estimated the scale of this design cost excess to

be in the range of £2.3m – £4.0m, and that overall, the onshore substation cost submission exceeded the expected efficient costs by between £2.0m – £3.7m.

Ofgem's view

2.57. Since we set the indicative transfer value the Project's onshore substation costs have reduced. Following the review undertaken by KEMA, we have concluded that it was appropriate to revisit the estimate made for the indicative transfer value and following a detailed review of all information provided we have decided that £2.85m should be removed from the Project's assessed costs. We consider that this reflects the economic and efficient costs when considering the procurement exercise that was undertaken for the Project's onshore substation. Given that we had originally made a £12m reduction to the Developer's indicative transfer value submission, this revised position represents a £8m variance to the indicative transfer value Capex allowance.

Onshore and Offshore spares

2.58. For the indicative transfer value, the Developer included just under £1.9m for spares. For the final transfer value, the Developer requested £2.6m for onshore and offshore spares following a request from the preferred bidder to purchase a larger list of spare parts. We sought further information and clarification of the proposed costs. The value of the additional spares requested for inclusion in the final transfer value was £667k. The Developer confirmed that this cost covered the preferred bidder's additional spares requests and procurement costs incurred by a supplier, which were not covered by contractual arrangements.

Ofgem's view

2.59. We note that the Developer and preferred bidder have reached a negotiated position on the Project's required spares. We have accepted the Developer's position on the procurement fees as this was an unavoidable Project cost. We have accepted the substantiation provided by the preferred bidder and we have concluded that the costs of acquiring the spares have been incurred economically and efficiently. Therefore, we have included the additional cost of £667k in the assessed costs.

Development costs

2.60. The assessed development cost for the Lincs transmission assets is £35.6m. These are costs incurred by the Developer which were outside the scope of the main construction contracts. For the purpose of informing our cost assessment, GT investigated the Project's development costs. The main outcome of the investigation was to confirm the basis for cost allocation metrics between the transmission and generation assets.

Accuracy and allocation of development costs

2.61. When the indicative transfer value was set in July 2011, development costs were estimated at £18.1m[3]. The Developer has submitted a final claim for development costs of £40.9 million.

2.62. For the Project's indicative transfer value, a ratio of 25:75 was used to allocate shared costs between the transmission assets and the generation assets. The Developer has applied this ratio to some shared costs in their final cost submission. Where actual data is available, OFTO related costs have been used.

Ofgem's view

2.63. We have reviewed and considered the rationale for these allocations and consider that the costs have been appropriately allocated, on the basis of the detailed timesheets supplied by the Developer.

Efficiency of Development Costs

2.64. The development costs submitted by the Developer have increased relative to the value in the indicative transfer value by £22.8m. The Developer has stated that this is due to an increase in project management costs, caused by extended construction timelines and additional contractual interfaces.

2.65. The Project experienced construction delays, largely as a result of the nearshore installation problems. This has extended the length of time taken to complete construction and also increased the amount of project management resource required to manage a number of technical issues.

2.66. When the cable installation contractor Subocean Limited went into administration, the Developer was required to source replacement contractors. No single contractor was able to perform the cable installation contract, so a number of contractors were appointed

2.67. The Project required additional project management time and resources to manage this multi-contract solution.

Ofgem's view

2.68. We have considered the Developer's submission and the level of their proposed increase in development costs. We agree that given the increased scale and complexity of the operation following the withdrawal of Subocean Limited, it is appropriate for additional development costs to be included in the assessed costs. However, some of these costs are associated with activities that we have already

[3] We arrived at this sum after making reductions from its submission of £0.9 million for unsubstantiated general development costs and £1.3 million for project risk costs that were within the Developer's control.

deemed inefficient: elements of the HDD operation, the use of rollers and the mobilisation costs of the 2012 campaign.

2.69. We have considered how to implement a reduction from the Developer's submission that reflects the costs expended on these inefficient activities. We have decided that the submitted development cost increase since the indicative transfer value should be scaled back in the same proportion as we have scaled back the Capex increase associated with these extra cable-laying works. Accordingly, we are not including £5.3m of submitted development costs in the assessed costs.

Interest during construction

2.70. The Developer's proposed IDC was £45.1m. This is based on the Developer's calculation of the interest rate to completion of the assets over a period from November 2007 to end of November 2012. The main change from the indicative transfer value is a result of the inclusion of additional Capex arising from the cable installation process.

We reviewed the Developer's IDC submission which has resulted in a number of IDC changes. The net impact of these changes was a £10.1m reduction to the Developer's IDC claim. The total IDC calculated for the Lincs transmission assets after reductions is £35.0m.

Accuracy and allocation of IDC

2.71. The Lincs transmission assets were constructed over the period November 2007 to November 2012. In July 2011, Ofgem consulted on the interest rate to be used to calculate the level of IDC for projects in the transitional tender rounds. We published our decision letter and explained that we will apply a capped rate[4] of 8.5 per cent from 1 December 2011. IDC incurred prior to this date is capped at a rate of 10.8 per cent. Two different IDC rates have been applied across that period: 10.8 per cent from November 2007 until November 2011, and 8.5 per cent from December 2011 until November 2012.

Completion of transmission assets

2.72. In determining the Project's IDC we have discussed with the Developer the operational status of the transmission assets. In particular, we reviewed the IDC submission and identified that the Developer had claimed IDC for the period November 2007 to the end of November 2012 on elements of the transmission assets that were in service and operational. IDC can only be recovered for financing costs incurred by a Developer in the period of developing and constructing the transmission assets. The Lincs transmission assets became operational in July

[4] We will apply the developer's rate (subject to economic and efficiency assessment), if that is below the capped rate

2012; therefore, we removed the IDC claimed on these operational elements. This resulted in a reduction of £4.7m.

Efficiency of IDC

2.73. The IDC caps were applied to the Developer's indicative transfer value and for the assessed costs these caps remain. Accordingly, we consider that the rates applied to the Developer's submission are acceptable.

2.74. By considering our own modelling of the likely time required to develop and construct assets of this nature and the time taken by other developers on the projects in the transitional tender rounds, we have concluded that three seasons is an inefficient length of time taken by the Developer to install the cables. Therefore, we have considered whether a curtailment of the Developer's IDC submission is appropriate. We note the difficulties that the Developer experienced during the nearshore cable laying process.

2.75. Following our comparison of Projects as described above our decision is to reduce the period for which the Developer is entitled to IDC by three months. The reduction in IDC has been scaled across the entire construction overrun period to avoid disproportionate effects arising from varying cash flows over that period. The impact of this adjustment is a reduction of £3.4m on the Developer's final cost submission. This adjustment is in addition to the accuracy adjustment noted above.

2.76. The Capex and project management reductions relative to the Developer's submission, as set out in previous sections, have resulted in a further reduction of £2m to the Developer's IDC claim.

Transaction costs

2.77. The indicative transfer value did not contain any transaction costs as they were not known at the time. The Developer has subsequently submitted a firm estimate of the costs they expect to incur to asset transfer. The total of these items results in the transaction cost element of the submitted transfer value being £2.7m.

Accuracy and allocation of transaction costs

2.78. 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, e.g. legal, accountancy and technical. We have concluded that the costs provided by the Developer were allocated appropriately.

Efficiency of transaction costs

2.79. Transaction costs can only be provided to us by developers to a reasonable degree of accuracy towards the end of the tender process. The transaction costs submitted by the Developer represent approximately 1 per cent of the total Capex and development costs. We have considered the types of resource costs incurred in relation to this Project's tender process and these transaction costs appear reasonable.

Contingency

2.80. The assessed costs do not contain a separate contingency value. The contingency provision of £22.4 million at the indicative transfer value stage has been utilised to deal with the cable installation issues.

Confirmations in relation to tax benefits

2.81. The indicative transfer value 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 final transfer value we would reduce the assessment of costs for an amount that reflects the value of the tax benefit retained by the Developer. For the final transfer value the Developer has confirmed that the purchaser will be able to obtain the full benefit of all available capital allowances and therefore it has not been necessary to reduce the assessment 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 Lincs transmission assets to be £307,728,310.36.

Appendices

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Appendix 1 - Glossary

A

Authority

The Gas and Electricity Markets Authority

C

Capex

Capital Expenditure

D

Developer

Lincs Wind Farm Limited

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

MEGAVOLTAMPEREO

OFTO

Offshore Transmission Owner

P

Project

The development and construction of the Lincs offshore transmission assets

PTRA

Post Tender Revenue Adjustment

Q

QTT

Qualification to Tender