Offshore Transmission: Cost Assessment Report for the Robin Rigg Transmission Assets

Document Type: Decision Document

Ref: Insert Reference

Date of Publication: 03 March 2011

Target Audience: All those interested in offshore transmission

Overview:

This document describes our cost assessment for the Robin Rigg transmission assets and the key principles that we have applied in our cost assessment process for the first transitional tender round. The Authority has used the assessment of costs to determine the transfer value of the Robin Rigg transmission assets. The Authority has granted an offshore transmission licence to TC Robin Rigg OFTO Limited which is incorporated by Transmission Capital Partners (a consortium of Transmission Capital, International Public Partnerships and Amber Infrastructure Group). Transmission Capital Partners 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.

Contact name and details: Roger Morgan, Senior Manager, Developer Engagement; Tom Suddaby, Manager, Developer Engagement

Tel: 020 7901 0525; 0207 7901 7263

Email: roger.morgan@ofgem.gov.uk; tom.suddaby@ofgem.gov.uk

Team: Offshore Transmission

Context

Ofgem[1] and the Department for Energy and Climate Change (DECC) have developed a regulatory regime for offshore electricity transmission. A key part of this regime is that offshore electricity transmission licences will be granted to Offshore Transmission Owners (OFTOs) 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[2].

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. 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 in the transitional regime. The Tender Regulations provide for an estimate and 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 successful bidder.

At the time we commenced the cost assessment process the transmission assets of the projects in the first transitional tender round, other than Barrow, were still under construction. For these projects we carried out an estimate of costs under the Tender Regulations before commencing the assessment of costs.

Associated Documents

- Offshore Transmission: Notice under section 8A(3) of the Electricity Act 1989 (Robin Rigg)
- The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2010
- Offshore Electricity Transmission: Tender Rules
- Offshore Electricity Transmission: Final statement on competitive tender process
- Draft cost assessment report for the Robin Rigg Transmission Assets

1 The Gas and Electricity Markets Authority is the regulator of gas and electricity markets in Great Britain. Ofgem is the Office of Gas and Electricity Markets, which supports the Authority in performing its statutory duties and functions. Whilst the terms "Ofgem" and "The Authority" are used interchangeably in this report, it is the Authority which is responsible for exercising the relevant statutory powers.

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

Table of Contents

Appendices (provided as separate pdf documents)

Summary

This document is a cost assessment report for the first transitional tender round (TR1). It sets out the assessment of costs which ought to have been incurred in connection with the development and construction of the transmission assets for the Robin Rigg project and details the cost assessment process we have undertaken in this respect.

Key stages of the cost assessment process for Robin Rigg

The cost assessment process involved three key stages set out below.

- The initial calculation of costs for the Robin Rigg project was £58.7m. This was communicated to the developer in July 2009 and published in the preliminary information memorandum in September 2009 (the initial transfer value).
- The initial calculation was updated as a result of further information and continuing analysis. The updated calculation, which was £57.3m, was communicated to the developer in September 2009 (the indicative transfer value). The indicative transfer value was published in the information memorandum.
- At this stage of the cost assessment process we have reached a final decision on the assessment of costs of £65.5m (the assessed transfer value).

The Robin Rigg project

The table below shows the movement between the initial, indicative and assessed transfer values, and the reasons for these movements, broken down across the cost categories.

Table 1: Summary of cost breakdown history

Category	Initial transfer value (July 09) £m	Indicative transfer value (Sept 09) £m	Assessed transfer value (Nov 10) £m	Reasons for development
Capex	49.2	50.1	49.5	Reduction from indicative due to removal of contingency and foreign exchange hedging gains
Development	5.3	4.4	4.4	No change in overall value. However, inclusion of £0.2m for extra works required for NGET reporting
IDC	4.1	2.8	10.9	Increase due to evidence of higher interest rate and updated split cashflows for both phases with separate IDC end dates
Transaction	0.0	0.0	0.7	Transaction costs not assessable until end of cost assessment process
Total	**58.7**	**57.3**	**65.5**	The increase is largely a result of the higher IDC value

Capex

Capex costs have altered slightly from the initial transfer value to the assessed transfer value. This is a result of forecast figures becoming actual figures in combination with the removal of hedging gains related to contracts which were in Euros.

Development costs

The reduction in development costs from the initial transfer value is largely a result of the removal of contingency which was included in the developer's original submission for the initial transfer value.

Interest during construction

The IDC allowance has increased from the initial transfer value to the assessed transfer value. This is a result of two factors. The first is an increase in the interest rate used. E.ON submitted a higher rate than used for the initial transfer value and provided the evidence to support this. The second is the result of calculating IDC using split cashflows for each phase of the project, which result in a longer overall period of application.

Transaction costs

The transaction costs are composed of both internal and external resource costs of the tender process for the developer as well as tender fees that the developer has paid to Ofgem through the tender process. We have checked these costs to ensure that they have been correctly allocated by the developer.

Confirmations in relation to tax benefits

The developer has confirmed that the incoming OFTO will be able to obtain the full benefit of all available capital allowances. Therefore, no reduction to the assessment of costs has been made.

Assessed transfer value for Robin Rigg

The assessed transfer value of the Robin Rigg project transmission assets is £65,516,330.

1. Cost assessment process for TR1

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 in the transitional regime. This chapter sets out the process that we followed in carrying out the TR1 cost assessment.

Overview of the TR1 cost assessment process

1.1. The Tender Regulations provide the legal framework for the process which Ofgem will run for the grant of offshore electricity transmission licences. This process includes assessing the economic and efficient costs of constructing and developing 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.
- 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.

Data collection

1.3. To undertake this exercise we have gathered and reviewed a range of information and supporting evidence. Detailed cost information was provided by developers in the form of cost reporting templates, contract values, asset cost schedules and cash flows. These relate to the actual/forecast costs of construction contracts and development costs related to the transmission assets being transferred to the successful bidders.

1.4. The data collection to inform the cost assessment process commenced in December 2008 and has continued to date. Throughout this period we have worked closely with the developers of the relevant offshore transmission assets. The information we have gathered relates to the following cost categories that are involved in the development and construction of the transmission assets:

- Capital expenditure
- Development costs
- Interest during construction
- Transaction costs.

1.5. Developers have also provided supporting evidence to substantiate their cost submissions including, amongst other things, contract documentation, supplier payment lists and asset schedules. We have been supported throughout this process by Ernst and Young as financial advisers and KEMA as technical advisers.

Process stages

1.6. The cost assessment process for the first transitional tender round involves the key stages set out below.

Initial transfer value

1.7. The initial transfer value calculated in July 2009 was based on cost submissions by the developer of each project. This value was made available to bidders at the Pre-Qualification (PQ) stage of the tender process. The letter we sent to developers at this time (appendix 3) indicated that this calculation might be updated as a result of any further information provided by the developer and our continuing analysis.

Indicative transfer value

1.8. In September 2009, we provided the indicative transfer value for the commencement of the Qualification to Tender (QTT) stage of the tender process. This value was also used for the tender revenue stream bids submitted by bidders at the Invitation to Tender (ITT) stage. The letter we sent to developers in September 2009 (appendix 4) indicated that this calculation might be updated as a result of any further information provided by the developer and our continuing analysis. For projects where the transmission assets were not yet available for the use of transmission (being all projects other than Barrow), this letter also provided a guarantee (subject to certain matters) that the minimum transfer value they would receive for the transmission assets once their project was completed would be 75% of the indicative transfer value.

Assessed transfer value

1.9. Once the transmission assets are complete or are close to completion and the developer has indicated that they have documentation to support an assessment, we will commence an exercise to determine the assessed transfer value.

1.10. A draft of the cost assessment report, including the amount of the assessed transfer value, will be sent to the developer and the preferred bidder for the relevant project. This enables either of these parties to comment on the factual nature of the report prior to the cost assessment being finalised by Ofgem.

Updated indicative transfer value

1.11. Where it is not possible for us to complete the cost assessment prior to the asset transfer we will determine what proportion of the indicative transfer value the developer should receive on transfer of the transmission assets. This may be greater than or equal to the 75% minimum transfer value referred to in 1.8. We will also consider whether the indicative transfer value itself should be updated in light of further evidence arising from our cost assessment process since the indicative transfer value was published.

1.12. The indicative transfer value (updated where relevant) will then be incorporated into the tender revenue stream of the preferred bidder for the project along with the relevant cash flow reflecting the staged payment of the transfer value to the developer.

1.13. Once final costs are known and the developer can provide documented evidence, we will proceed to finalise our cost assessment. The deferred consideration (being the difference between the assessed transfer value and the proportion of the indicative transfer value received by the developer on transfer) will then be paid by the OFTO to the developer and the Post Tender Revenue Adjustment (PTRA) mechanism in the licence will be used to reflect the assessed transfer value.

Cost assessment analysis for TR1

1.14. Throughout the stages described above we have applied two tests.

<u>Test 1 - Assessing the accuracy and allocation of developers cost submissions</u>

1.15. As a first test we have checked the accuracy of developers' data and the appropriateness of cost allocations in particular between the offshore generation and transmission assets. Throughout the cost assessment process, developers have provided cost information to us on an ongoing basis. Where we have identified discrepancies in how developers have allocated these costs we have checked with them to assess if they have been allocated to the correct asset category and made adjustments accordingly.

1.16. To support the cost assessment process we have also undertaken a forensic accounting investigation (appendix 7). The scope of this investigation was shared with developers in advance. This investigation was based on the final costs that the developer has provided to us and was applied to a sample of contract costs. The actual sample for each project varied due to the different contracting strategies adopted by the developer and the specific needs of the project, but generally focussed on the most expensive contract and/or contracts which had material increases in costs such as export cable supply and installation contracts.

1.17. The forensic accounting investigation was undertaken primarily to validate the cost allocations provided by developers. This may have indicated the need for amendments to the developer's submissions to reflect, for example:

- the actual costs incurred (eg in respect of exchange rates on foreign currency payments)
- more relevant metrics for the allocation of shared service costs.

1.18. Where amendments were required we incorporated the recommended changes from the forensic accounting investigation unless the developer was able to provide further evidence to substantiate the original allocation.

Test 2 - Assessing if developer's costs are economic and efficient

1.19. Under test two we sought to assess through appropriate analysis whether the costs had been economically and efficiently incurred by the developer. Where possible, we have sought to apply benchmarking and where industry wide cost indices were unavailable we have reviewed data from other projects within the first transitional tender round. This analysis has included benchmarking across the projects (see 1.21 below) in the first transitional tender round and analysis in relation to funding interest rates (see 2.14 - 2.20 below). We consider such approaches to be an important tool in assisting us to ensure these costs are economic and efficient.

1.20. To help us calculate the indicative transfer value we undertook a benchmarking exercise (appendix 5) using comparable costs across all projects in the first transitional tender round to identify any cost outliers across the main cost categories. Any cost outliers identified through the benchmarking exercise were then subject to further review. This exercise examined 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 secure 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
- development cost as a percentage of transmission assets.

1.21. This benchmarking exercise informed our communication to developers in our letter of September 2009 which set out the indicative transfer value.

1.22. We have also considered the procurement processes adopted by developers to obtain economic and efficient transmission asset costs. We have noted the differing procurement approaches taken by developers for the transmission assets in the first transitional tender round. We will keep the efficiency of developer procurement and contract management approaches under close review for future cost assessments.

1.23. Where capex or development costs have increased since the indicative transfer value was set, developers have been asked to provide supporting documentation and justify why these increases incurred. Depending on the nature of the increase, we have undertaken a technical investigation which focussed on, for example, a particular cost increase in a distinct contract or multiple increases across several contracts.

2. Cost assessment principles

Chapter Summary

This chapter sets out the cost assessment principles we have adopted in determining the assessed transfer value for the first three projects within TR1 (Barrow, Robin Rigg and Gunfleet Sands). We intend to apply these principles in our cost assessment process for other projects in TR1. However, we may need to vary them or apply additional principles where appropriate in light of the analysis undertaken in respect of such projects.

Introduction

2.1. This chapter sets out the cost assessment principles we have adopted in relation to various cost categories for TR1 and the reasoning for such principles.

2.2. The principles set out in this chapter are:

- allocation of costs
- economically and efficiently incurred costs
- interest during construction
- treatment of contingency
- spares
- tax - VAT
- tax - capital allowances
- depreciation of operational projects
- transaction costs
- outstanding costs
- capitalisation of operating costs.

Allocation of costs

Capital expenditure

2.3. On all projects, there were some costs submitted by developers that have been split between generation and transmission. An example of this is where the cable installation contract covers both the export cables (transmission) and the inter array cables (generation) or if a seabed surveys cover the entire wind farm. In such instances we have requested the allocation methodology and metrics that the developer has used to determine what proportion of the costs have been allocated as transmission costs. Such a methodology may be based on the relative proportion of direct equipment costs (ie excluding all shared costs) for the transmission assets compared to the project as a whole. We have then cross-checked that the allocation of cost was based on the methodology and considered metrics applied in order to ensure accuracy.

Development costs

2.4. Developers submitted a range of differing development costs, such as the cost of undertaking design studies, seabed surveys, project management, costs related to gaining consents and the cost of acquiring the development rights from another party.

2.5. With support from our technical advisers we have analysed developers' initial cost submissions for development costs (see appendix 5). At the time of this work our analysis showed that the range of development costs represented a high percentage of the total project costs (excluding financing). Our advisers have indicated that development costs typically represent between 10-15% of total project costs (for projects in the first transitional tender round). In calculating the assessed transfer value we have reviewed whether development costs are broadly in line with the range provided by our advisers. Where these differ markedly we have undertaken additional analysis to ensure that only appropriate development costs are allowed.

2.6. Given the wide range of different costs submitted across projects, it is important that these costs are allocated appropriately. We have required developers to identify these cost allocations. In some instances, costs have been identified that are more appropriately classified into other cost categories. Where this is the case developers were required to reallocate them.

Economically and efficiently incurred costs

Capital expenditure

2.7. Offshore transmission development and construction is a relatively new industry and industry wide cost indices are not yet readily available. In order to assess whether the capex totals proposed by developers were economically and efficiently incurred, we initially undertook a benchmarking exercise across all projects included in the first transitional tender round (appendix 5). This benchmarking exercise covered each of the main components of the transmission assets (ie cables, transformers, reactive equipment and onshore and offshore substations) and on an overall basis (eg cost per MW and as a percentage of the overall project including generation). Where any item of cost appeared to be an outlier above the norm, we carried out further investigations with the developer to assess if the costs were incurred on an economic and efficient basis.

2.8. Where expenditure on any main cost category or development costs had risen by a material sum since the indicative transfer value, further work was undertaken by our technical advisers to specifically review such cost items.

2.9. Together with the benchmarking data, we have noted the procurement and contract management approaches adopted by developers for the transmission assets. At this stage in the first transitional tender round we have decided not to apply a cap to any items of capital expenditure due to the limited comparable data at our disposal. However, we will keep this approach under review during TR1 and beyond as more data becomes available from completed projects.

Development costs

2.10. The development costs provided by developers may not be easily attributable to either the generation or transmission construction activities as they relate to the process of developing and constructing the offshore project (generation and transmission assets). We have therefore focussed our analysis on ensuring the allocation proposed by the developer is appropriate and that we have clarity on the reasons why costs may have changed during the cost assessment process.

2.11. At the indicative transfer value stage we compared the proportion of total costs represented by development costs on each project in order to identify specific areas for further review across all projects. At this stage in the first transitional tender round we have decided not to use this analysis to apply a cap on development costs due to the limited comparable data at our disposal. However, we will keep this approach under review during TR1 and beyond as more data becomes available from completed projects.

Changes in ownership

2.12. Many of the projects in the first transitional tender round have undergone changes in ownership (ie the original developer has sold the rights arising from initial development) in the period from the initial award of the Crown Estate lease up to the completion of the transmission assets. The shareholdings in some projects have been amended during the period in which the cost assessment has been undertaken. We consider that an appropriate allowance (one that is representative of the relevant development costs and which is included within the acquisition costs of these projects) can be included in the assessed transfer value. This is subject to the allowance representing only the underlying costs (including financing costs) of the development work undertaken up to the acquisition date. In checking that overall development costs are within an appropriate range (as set out in 2.5) this also provides a check that the costs incurred are appropriate, in light of project specific circumstances.

Interest during construction

2.13. IDC refers to the financing costs incurred by a developer in the period of developing and constructing the transmission assets. The total IDC for a project is driven by four key variables each of which needs to be economic and efficient. These are set out below and discussed in detail in the following sections:

- interest rate applied to the project
- duration of the financing
- cost items to which interest was applied
- resulting cash flow curve.

Interest rate

2.14. We have calculated IDC on a pre-tax nominal basis. The use of a pre-tax rate ensured that developers received a rate that enables them to meet the expected level of tax in the chargeable gain arising from the inclusion of financing costs in the assessed costs. This use of a pre-tax nominal basis is consistent with practice in onshore transmission price controls on reasonably incurred additional outlays not covered by the scope of the preceding price control.

2.15. For calculating the total IDC, developers were initially requested to provide cash flow information and the interest rates signed off on their project, supported by relevant internal (ie board level) documentation to verify the applicable rates. The first responses from developers were based on the rates sanctioned as part of their financial commitment to the project. These were used in calculating the indicative transfer value. We carried out further analysis on the interest rates for projects in the first transitional tender round and wrote to developers in April 2010 with the results.

2.16. This further analysis was required as the developers had provided a wide range of interest rates to be considered for the purposes of IDC and it was difficult to be confident that the variation could be explained by underlying economic factors. Given the wide range of interest rates proposed, we considered what an appropriate cost of financing for such assets should be and whether there were reasonable grounds to impose a cap on the interest rate. In the absence of comparable benchmark data from other projects we decided to use appropriate wider industry data as explained below. We used our own internal assessment in conjunction with a report by our financial advisers (appendix 6) to come to a conclusion on the appropriate cost of financing. The period considered by our financial advisers for their assessment of funding costs was 2005 - 2009.

2.17. As part of our assessment of appropriate interest rates, a number of factors were considered. Other than the first project completed (Barrow), the remaining projects in the first transitional tender round have largely been constructed and financed in the "credit crunch" period. One of the features of this was a reduction in the liquidity of project finance, making corporate funding the main if not the only funding source for projects. The entire transmission element of construction for projects in this tender round has been financed by the generation arm of an integrated European energy utility (ie Centrica, Dong, E.ON, RWE, SSE, or Vattenfall). These companies have on average a much smaller proportion of debt in their total funding than either a regulated European transmission utility (eg National Grid, Red Electrica and Terna) or the special purpose vehicle (SPV) usually used for energy projects (but for which liquidity was poor at this time).

2.18. The E&Y report concluded that the range of interest rates for the upper end of appropriate financing costs was 9.4-10.8%. Given the relative impact of the credit crunch and associated funding volatility, the gearing and beta levels proposed by our advisers and in order to be consistent across projects funded in the same period, we concluded that adopting the top end of the range would be appropriate. In April 2010 we wrote to the developers whose project interest rates were above 10.8% to inform them that, based on our analysis at that time, their rates were to be capped at 10.8%.

2.19. Where the developers provided evidence of a rate below the cap, their proposed level of interest rate has been used.

2.20. We have noted in 2010 that the liquidity of funding for projects improved. The level of debt available for prospective bidders for the transmission assets provides an illustration of this. Where project delivery programmes are delayed such that the majority of project funding falls outside the period examined by our advisers we may consider reviewing the appropriate interest rate cap for such TR1 projects.

Duration of financing

2.21. Regulation 4 of the Tender Regulations provides that the Authority must calculate the economic and efficient costs of developing and constructing the transmission assets. We consider that construction ceases once the transmission assets are commissioned. The commercial supply of electricity to the transmission system which follows commissioning also indicates that the assets are complete and operational.

2.22. Each transitional project developer will have a project specific commissioning programme for the assets that it is constructing. It is important to differentiate between commissioning activities that are associated with the transmission assets and the wind farm generation assets. Before generation assets can be fully commissioned, the commissioning of the transmission assets will need to have reached a stage that permits safe energisation of the transmission system and provides an offshore transmission system that is ready to transport electricity on a commercial basis. There may be occasions where transmission asset and generation asset commissioning activities occur in parallel.

2.23. With these distinctions in mind, we have determined that IDC should be allowed up to the point where the transmission assets have been constructed and are fit for use as a system, or as part of a system, for the use of transmission of electricity. Where projects are phased, IDC will cease at the completion of each individual phase in accordance with the same principles. If we consider there is evidence of inefficient and uneconomic delays in the construction or commissioning programme for the transmission assets, the period of applicability may be curtailed to reflect this.

2.24. Where projects have been purchased from other developers, we consider that the IDC should commence on the date of the acquisition. IDC is not applied to the period over which the previous developer incurred costs because the purchase cost will reflect this.

Cost items to which interest was applied

2.25. IDC is only applicable to the cash flow that represents the capital expenditure and development costs. Where the project has been purchased from another developer IDC is calculated on the allowance included in accordance with 2.12. Where amendments have been made to the developers submitted cost information from either the allocation or efficiency test this has been reflected in the cash flow. This ensures that the IDC calculated for the transmission assets reflects the economic and efficient cost of developing and constructing the assets.

Cash flow curve

2.26. IDC is calculated on the actual cash flow which represents when payments were made against the contracts for developing and constructing the transmission assets. Some developers have sought to apply IDC to accounting data rather than their actual cashflows. This has not been used to calculate IDC as it does not represent the actual cost to the developer and includes non cash elements such as retentions, accruals for work completed and provisions. Where developers have provided accounting data or this has been identified during the forensic accounting investigation we have sought the correct information from the developer.

Treatment of contingency

2.27. For projects still in the design or construction phase, developers' cost data forecasts for the initial and/or indicative transfer values have tended to include contingency amounts to deal with future uncertainty over the actual cost and timing of construction. The assessed transfer values do not include any contingency because construction has been completed and all costs should be either settled or agreed with suppliers or the developer should have provided a firm estimate (eg on tender costs). As a result, contingency has reduced to zero for the assessed transfer value.

Spares

2.28. Where spares for the transmission assets are to be transferred to the OFTO then we will allow them as part of the assessed transfer value, provided that they can be demonstrated to be economic and efficient.

Tax - VAT

2.29. HMRC have provided guidance in relation to whether the transfer of transmission assets can be viewed as a transfer of a business as a going concern (TOGC). HMRC have indicated that they would expect (subject to exceptional circumstances) that any transmission assets that are currently operational or fully constructed up to the point of operation at transfer would meet the TOGC conditions. Should any circumstances occur in which the transfer does not meet TOGC conditions and therefore is not free of VAT (eg as a result of further discussions between the developer, preferred bidder and HMRC), then the parties should seek arrangements with HMRC to minimise the working capital consequences of such a situation. This will have no impact on the assessment of costs or assessed transfer value.

Tax - capital allowances

2.30. Each transfer of assets from a developer to an OFTO under the transitional tender round is for a set of assets on an as-built basis, based on actual expenditure. We have therefore assumed for the cost assessment process that the purchaser will obtain the full benefit of all available capital allowances and that the transfer value should be reduced where such benefits do not fully pass across. This position was referenced in our letter to developers in September 2009 (appendix 4). The indicative transfer value has been calculated on the basis that the purchaser obtains the full benefit of all available capital allowances. Where benefits do not fully pass across and any such tax benefit is retained by the developer (eg as a result of agreement reached between the developer and preferred bidder), which results in the purchaser not being able to obtain the full benefit of all available capital allowances, we will reduce the assessment of costs. This reduction will be for an amount that reflects the value of the tax benefit retained by the developer.

Depreciation of operational projects

2.31. There are some projects in the first transitional tender round that have been operational for a period of time prior to the assets being transferred to the OFTO. We have considered depreciation in relation to such projects.

2.32. The design life indicated by manufacturers for offshore transmission assets is greater than 20 years. Therefore, based on the assumption that the assets are capable of satisfying the 20 year life applicable to the revenue entitlement set out in the OFTO licence, and in the absence of evidence to suggest they will not do so, we therefore consider it reasonable not to apply depreciation to the assets.

Transaction costs

2.33. Transaction costs relate to the costs that the developer has had to incur as a result of the tender process. These can be split into two categories:

- tender fees
- developer's external and internal costs.

Tender fees

2.34. Tender fees relate to the fees charged to the developer by Ofgem as part of its cost recovery methodology. We are including these costs as transaction costs in the assessed transfer value. This is consistent with the costs incurred in the development and construction of a set of assets that are being prepared for sale immediately following completion of construction.

2.35. Regulation 5 of the Tender Regulations set out that where the Authority has undertaken an estimate of costs under the Tender Regulations, the developer has to make a payment in accordance with the Authority's cost recovery methodology[3] in relation to the Authority's costs in this respect.

2.36. Regulation 7 of the Tender Regulations sets out that the developer is required to make a payment for the Authority's tender costs as calculated in accordance with the Authority's cost recovery methodology for that tender exercise. For the first transitional tender round, developers have been required to pay the Authority an administration fee of £50,000. This fee is considered to be a transaction cost and is recoverable by the developer.

2.37. Regulation 7 also sets out that developers are required to provide security in relation to the Authority's tender costs. For the first transitional tender round this was set on a sliding scale commencing at £500k per project. Developers were required to either provide this amount to Ofgem to be placed in an escrow account or in the form of a letter of credit (LOC). The costs of putting this LOC in place are included as transaction costs. Where security was provided into an escrow account, the developer will be entitled to the interest that the account has received. Where the security is returned to the developer any interest incurred along with the principle sum will also be returned.

Developer's external and internal costs

2.38. To support their activities in the tender process developers may have had to utilise a range of resources or services including, for example, the production of legal documents or provision of financial advice to support the cost assessment. The use of external and internal resources by developers to support the tender process in this way is consistent with the costs incurred in the development and construction of a set of assets that are being prepared for sale immediately following completion of construction.

2.39. For the purposes of undertaking a cost assessment we have required developers to submit evidence to support the level of external and internal costs that they have submitted. These may be reviewed as part of the forensic accounting investigation.

2.40. For internal costs, developers are required to submit the names of personnel involved, the activities that they worked on, their day rates and the number of days spent on tender activities versus the number of days spent on the total project (non tender related activities) in order to substantiate any claims for such costs.

2.41. There may also be internal specialised staff charged directly to the project for undertaking work directly related to the tender process, eg this could include engineers, accountants, etc. Where this is the case we would similarly require the appropriate evidence of this.

[3]http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Offshore%20Electricity%20Transmission%20Tender%20Rules.pdf

Exchange rates

2.42. We recognise that developers will have adopted different approaches for paying contracts in foreign currency. For example, the developer may have hedged by fixing the forward exchange rate in advance. The payment of their contracts should then be based on such fixed rates. If the developer has not used this approach then the exchange rate must be based on the day rates applicable when payments were made out against the contract in line with the standard accounting application of temporal rates. We have asked developers to outline their approach and provide supporting documentation as necessary. Where developers are unable or unwilling to provide the relevant calculations then we will determine the rate based on the forward rates applicable at the time that the contract approval was made.

Outstanding costs

2.43. When the cost assessment process is completed, cash payments made by the developer may not equal the assessed transfer value because there may be a number of outstanding non-cash items such as retentions, accrued invoices and provisions for work that is yet to be completed. If the level is significant (eg greater than 5%), we have delayed our final assessment until a lower and more accurate figure is available. Where these non-cash items have been assessed to be reasonable and do not amount to a significant percentage of the assessed transfer value they are treated as a firm commitment by the developer to allow the assessment to be completed.

Capitalisation of operating costs

2.44. We have decided not to allow the capitalisation of operating costs as this is not within the scope of the cost of developing and constructing the transmission assets. Examples of these costs include set up costs relating to ongoing operational costs (eg maintenance) that may have been capitalised.

3. Robin Rigg Cost Assessment

Chapter Summary

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

Robin Rigg transmission assets

3.1. The Robin Rigg Wind Farms (East and West) are located in the Solway Firth and have a combined installed capacity of 180MW. The Robin Rigg West transmission assets were commissioned in September 2009 and the Robin Rigg East transmission assets were commissioned in January 2010. The Robin Rigg Transmission Assets and the Robin Rigg Wind Farms (East and West) are owned by E.ON Climate and Renewables UK Robin Rigg East Limited and E.ON Climate and Renewables UK Robin Rigg West Limited respectively.

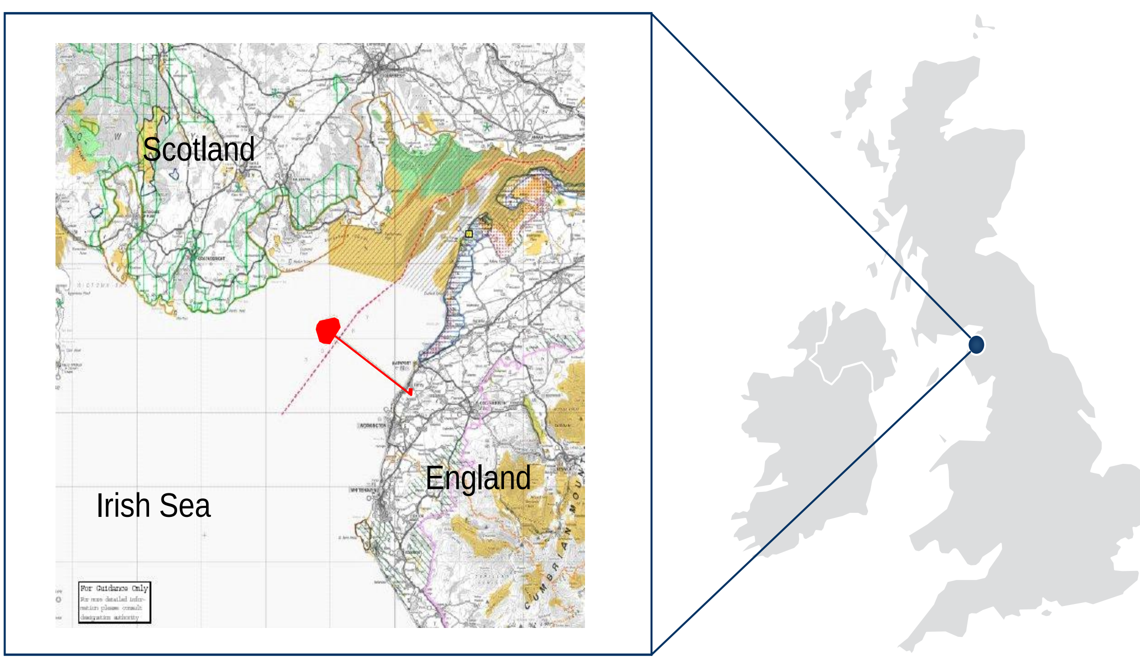


Figure 1: Location of the Robin Rigg transmission assets

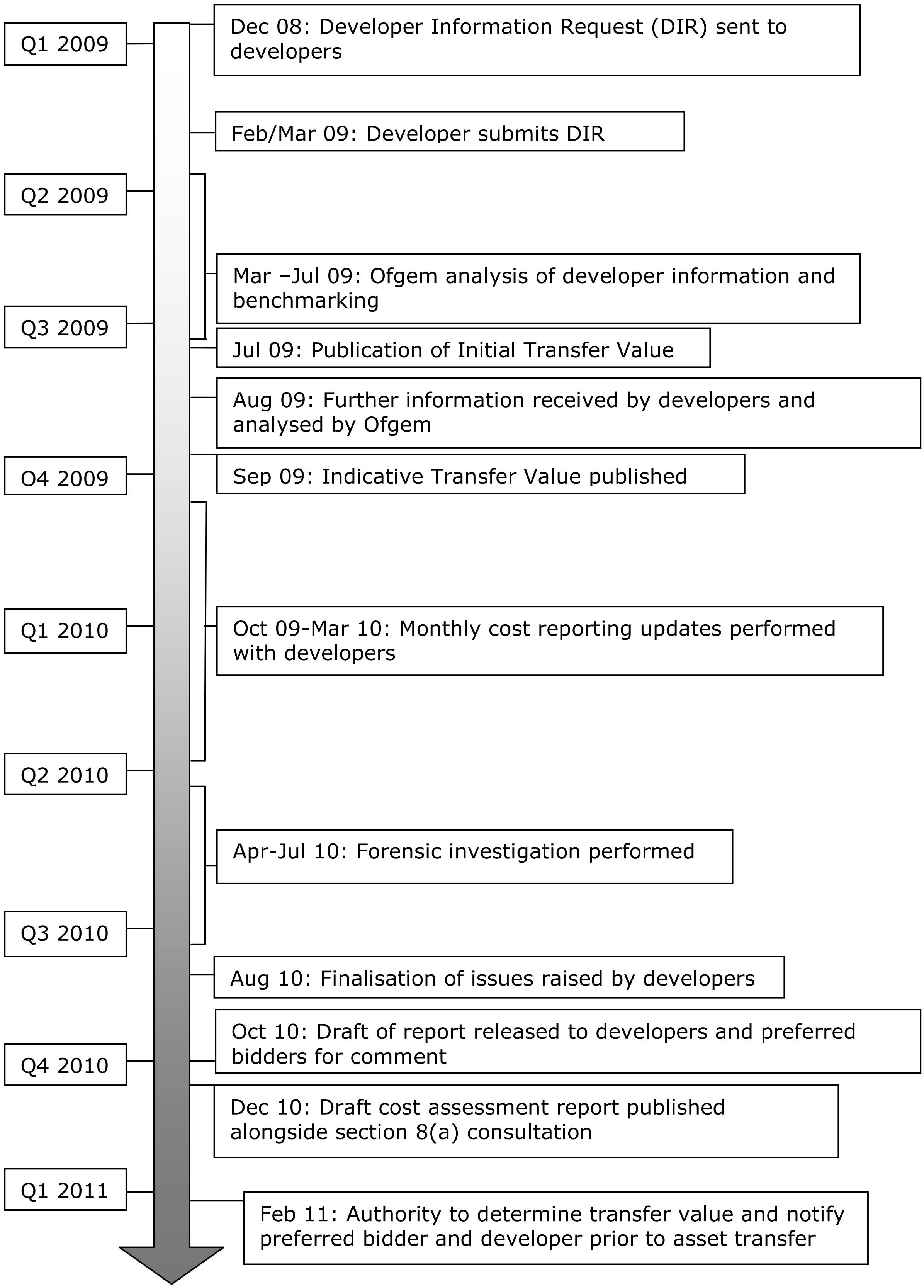
3.2. The assets that are transferring to the OFTO are the export cables and the onshore substation (note that the offshore substation is not being transferred). The boundary points are defined below.

- Offshore: Located at a point 300mm below where the 132kV single cores pass through the 132kV disconnector module base plate.
- Onshore: Located at the 132kV overhead bus-bar Palm connections to the High Accuracy Metering Unit.

3.3. Spares that are to transfer to the OFTO are three sections of submarine cable as well as a selection of spares for the onshore substation assets.

Robin Rigg cost assessment process overview

3.4. Since December 2008, we have worked with the developer and our advisers to reach the assessed costs which have been used by the Authority to determine the transfer value of the transmission assets. Chapter 1 set out the generic process for the cost assessment. The diagram below outlines the steps that have been taken in the cost assessment process for the Robin Rigg project.


Q1 2009
Dec 08: Developer Information Request (DIR) sent to developers
Feb/Mar 09: Developer submits DIR
Q2 2009
Mar –Jul 09: Ofgem analysis of developer information and benchmarking
Q3 2009
Jul 09: Publication of Initial Transfer Value
Aug 09: Further information received by developers and analysed by Ofgem
O4 2009
Sep 09: Indicative Transfer Value published
Q1 2010
Oct 09-Mar 10: Monthly cost reporting updates performed with developers
Q2 2010
Apr-Jul 10: Forensic investigation performed
Q3 2010
Aug 10: Finalisation of issues raised by developers
Q4 2010
Oct 10: Draft of report released to developers and preferred bidders for comment
Dec 10: Draft cost assessment report published alongside section 8(a) consultation
Q1 2011
Feb 11: Authority to determine transfer value and notify preferred bidder and developer prior to asset transfer

Cost allocation and efficiency

3.5. This chapter details the breakdown of the assessed costs for the capex, development, IDC and transaction cost categories.

3.6. In Chapter 1 we set out the two tests that were applied to the costs submitted by the developer. These were to assess:

- the accuracy and allocation of the costs
- whether these costs were incurred economically and efficiently.

3.7. The two tests were applied to the developer's costs submissions. In this chapter we identify the cost changes that have resulted from our assessment of the accuracy and allocation of the costs and how we have determined whether costs have been incurred economically and efficiently.

Allocation

3.8. The forensic accounting investigation was undertaken 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 period. It was also checked that they were allocated to the correct asset category and had been allocated correctly between generation and transmission. To assess whether the costs have been allocated correctly we have taken into consideration the following:

- metrics used when allocating costs
- developer's submissions using our cost reporting template
- a forensic accounting investigation (appendix 7)
- cash flow payments related to the transmission assets.

Efficiency

3.9. 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:

- a comparison between the initial and indicative cost submissions leading to the assessed transfer value
- a technical assessment of the project undertaken in 2009
- a benchmarking exercise undertaken in 2009 across all transitional projects to inform the indicative value (appendix 5)
- a report on interest during construction (appendix 6).

3.10. Robin Rigg is one of the first offshore projects to be assessed. Over time, as further projects are completed, it will be possible to make greater use of actual costs for benchmarking and adopt consistent metrics for cost allocation. This will be used in conjunction with the forensic investigation and technical assessments when determining the assessed transfer value.

Cost summary

3.11. The table below provides a breakdown of the evolution for the standard components of the project valuation.

Table 2: Cost breakdown history

Category	Initial transfer value (July 09) £m	Indicative transfer value (Sept 09) £m	Assessed transfer value (Oct 10) £m	Reasons for development
Capex	49.2	50.1	49.5	Reduction from indicative due to removal of contingency and foreign exchange hedging gains
Development	5.3	4.4	4.4	No change in overall value. However, inclusion of £0.2m for extra works required for NGET reporting
IDC	4.1	2.8	10.9	Increase due to evidence of higher interest rate and updated split cashflows for both phases with separate IDC end dates
Transaction	0.0	0.0	0.7	Transaction costs not assessable until end of cost assessment process.
Total	**58.7**	**57.3**	**65.5**	The Increase is largely a result of the higher IDC value

3.12. In total the asset transfer value for the Robin Rigg project increased from £58.7m to £65.5m from the initial transfer value through to assessed transfer value. As the table shows, whilst the overall value of the project has increased, the value associated with capital expenditure has remained broadly consistent. The variation is predominantly related to a higher IDC rate being adopted due to new information and evidence being submitted by the developer.

Capital expenditure

3.13. The total capex calculated for the Robin Rigg transmission assets in the assessed transfer value is **£49,459,408.**

3.14. The Robin Rigg project was constructed on a multi contract basis and we chose the four highest value contracts to investigate for the forensic accounting investigation. These accounted for 65% of the total cost of the transmission assets. The contracts that we investigated were:

- Prysmian Group (export cable supply)
- Subocean Group (cable installation)
- Oceanteam Power and Umbilical (cable installation)
- United Utilities Electricity plc (grid connection).

Allocation

3.15. We have analysed the information regarding the allocation of costs to the transmission assets presented to us by the developer. The majority of capex costs incurred on the project could be allocated to the transmission or generation assets in their entirety. Where costs have been split between generation and transmission, E.ON has allocated the percentage to the transmission assets using a cost driver. These cost drivers differ depending on the nature of the work undertaken. Only those costs related to the transmission assets were allowed for the initial, indicative and assessed transfer values.

3.16. Following the forensic accounting investigation no adjustments for the allocations of cost were made.

Efficiency

3.17. The benchmarking exercise that was undertaken to assist the conclusions on the initial and indicative transfer values did not raise a need for any efficiency adjustments on the capex costs for Robin Rigg. The capex costs have decreased slightly in the period between the indicative transfer value and the assessed transfer value. As there was no material increase in expenditure from the indicative transfer value we did not undertake a further technical investigation.

Development costs

3.18. The total development cost calculated for the Robin Rigg transmission assets in the assessed transfer value is **£4,393,394.**

3.19. These are costs incurred by E.ON which were outside the scope of the main construction contracts.

Allocation

3.20. A slight increase occurred in the development costs from the indicative to the assessed transfer value. The cost change was attributable to the work required for SCADA reprogramming and code requirement work offset by a small reduction in outturn costs across the cost categories.

3.21. During the process of calculating the assessed transfer value the developer confirmed that the initially submitted cost should be reduced. The reduction relates to SCADA equipment that is not required for the transmission assets.

3.22. The development costs have been allocated by the developer to the transmission assets based on a calculation of the proportion of total costs related to the transmission assets compared to an estimate of that spent on the generation assets.

3.23. The E.ON personnel cost is based on the developer's allocation of 25% of the total estimated project management costs. This allocation is based on the developer's estimate of project management time and cost relating specifically to the transmission assets.

3.24. Insurance costs have been determined by the developer by multiplying the total cost of the transmission assets by the insurance rates used by the developer. We have determined that this is a fair allocation of insurance costs.

3.25. We have analysed each of the allocations individually to ensure that they are appropriate.

Efficiency

3.26. The total development costs are 8.2% of the total cost of the transmission assets, excluding IDC. The total development costs as a proportion of the overall indicative transfer value was not deemed to be an outlier when compared to other projects and the subsequent cost change identified in the allocation test did not alter this position.

Interest during construction

3.27. The total IDC calculated for the Robin Rigg transmission assets in the assessed transfer value is **£10,918,275** based on E.ON's interest rate which was below the capped rate applied in the first transitional tender round.

Allocation

3.28. The Robin Rigg project is phased. The two phases are:

- Robin Rigg West (RRW)

- Robin Rigg East (RRE).

3.29. As stated in 2.23 where projects have phased commissioning we will calculate IDC separately on each phase.

Initial transfer value

3.30. For the initial transfer value, the IDC was calculated using the developer's submitted cashflow and interest rate. At the time these were not split into two phases.

Indicative transfer value

3.31. For the indicative transfer value the developer submitted a new cashflow for the project. They did not provide split cashflows for each phase at this time. Therefore the IDC for Robin Rigg could not be calculated on that basis. As a proxy for the split cashflows, for the purposes of the indicative transfer value, we calculated the IDC using the midpoint between the two commissioning dates (RRE and RRW) as the end date.

Assessed transfer value

3.32. The developer provided split cashflows with IDC ending on the respective commissioning dates for each phase. For the assessed transfer value the IDC has been calculated on this basis.

Efficiency

3.33. Of the early TR1 projects, Robin Rigg has the longest construction period over which IDC is calculated. This is due to project complexities and programme delays. The Robin Rigg transmission assets comprise of two separate offshore platforms serving the two separate wind farms (RRE and RRW). These offshore platforms are served by separate export cables which join with the onshore substation. This arrangement is unique amongst the early TR1 projects.

3.34. We have sought clarity from the developer on the specific nature of the construction programme delays. The causes identified by the developer are detailed below.

- At the beginning of the project Oceanteam Power and Umbilical (OPU) had been contracted to install all of the offshore cables for the Robin Rigg Wind Farms.
- In early 2008, OPU collected the 132kV export cables from Italy and shipped them to the UK. However, the site was not ready for the export cables to be installed as the onshore 'horizontal directional drill' ducts were not ready (necessary to allow the cables to cross beneath the railway lines at Seaton) and the offshore substation foundations had not yet been installed.
- The export cables were sent into temporary storage and the terms of the OPU contract were amended in June 2008 to reduce their scope of work to exclude

installation activity. The company experienced financial problems and failed to complete their reduced scope of work. In early 2009, OPU's UK operations went into liquidation.

- In July 2008 Subocean Group were appointed to install the export cables which was completed in April 2009 (RRW) and September 2009 (RRE).

3.35. The result of these factors was that construction was delayed by approximately a year. For the purposes of calculating IDC we consider that, given the particular circumstances for this project, there is no evidence of the construction and programme delays being inefficient and uneconomic. We have therefore calculated IDC on the full duration of the cashflow as described in 2.26.

3.36. E.ON submitted an interest rate that was used to calculate IDC for the initial and indicative transfer value.

3.37. For the assessed transfer value a rate was submitted by the developer which was higher than the rate applied for the initial transfer value. E.ON provided evidence that indicated that this was the rate at which the project was signed off at board level. This rate is below the level at which we have applied a cap on IDC. We consider this rate to be an economic and efficiently incurred cost and the IDC for the assessed transfer value has been calculated using this rate. It is this increase in the interest rate that is responsible for the majority of the IDC increase.

Transaction costs

3.38. The indicative transfer value did not contain any transaction costs as they were not known at the time. E.ON have submitted their view of the transaction costs incurred to date and a firm estimate of the costs they expect to incur to asset transfer. Consequently we have concluded that the transaction costs are **£745,253**.

Allocation

3.39. 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

3.40. Transaction costs can only be provided to us by developers to a reasonable degree of accuracy towards the end of the tender process. As the tender process for the Robin Rigg project is one of the first to be completed in the first transitional tender round there are a limited number of developers with transaction costs to which we can benchmark the cost. Furthermore, the costs that we do have are not directly comparable due to developers adopting differing approaches to meet the demands of the tender process and the fact that some developers have split their resource across multiple projects in the tender round. We have therefore not applied benchmarking but we have considered the reasonableness of the types of resource costs incurred in relation to the tender process.

3.41. As more tenders are completed we will have access to a greater pool of transaction costs that developers have incurred and it will be possible to make greater use of actual costs for benchmarking. We have otherwise relied on ensuring costs are accurate in order to ensure the associated value is appropriate.

Confirmations in relation to tax benefits

3.42. As stated in 2.30 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 assessed 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 assessed 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.

4. Conclusions

4.1. 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 Robin Rigg transmission assets to be £65,516,330.

Appendices

Index

Appendix 1 - The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute (such as the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Acts of 2004, 2008 and 2010) as well as arising from directly effective European Community legislation.

1.3. References to the Gas Act and the Electricity Act in this appendix are to Part 1 of those Acts.[4] Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This appendix must be read accordingly.[5]

1.4. The Authority's principal objective is to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or transmission systems. The interests of such consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases and in the security of the supply of gas and electricity to them.

1.5. The Authority is generally required to carry out its functions in the manner it considers is best calculated to further the principal objective, wherever appropriate by promoting effective competition between persons engaged in, or commercial activities connected with,

- the shipping, transportation or supply of gas conveyed through pipes;
- the generation, transmission, distribution or supply of electricity;
- the provision or use of electricity interconnectors.

1.6. Before deciding to carry out its functions in a particular manner with a view to promoting competition, the Authority will have to consider the extent to which the interests of consumers would be protected by that manner of carrying out those functions and whether there is any other manner (whether or not it would promote competition) in which the Authority could carry out those functions which would better protect those interests.

---

[4] Entitled "Gas Supply" and "Electricity Supply" respectively.
[5] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.

1.7. In performing these duties, the Authority must have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[6]; and
- the need to contribute to the achievement of sustainable development.

1.8. In performing these duties, the Authority must have regard to the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[7]

1.9. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed[8] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- secure a diverse and viable long-term energy supply,

  and shall, in carrying out those functions, have regard to the effect on the environment.

1.10. In carrying out these functions the Authority must also have regard to:

- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.11. The Authority may, in carrying out a function under the Gas Act and the Electricity Act, have regard to any interests of consumers in relation to communications services and electronic communications apparatus or to water or sewerage services (within the meaning of the Water Industry Act 1991), which are affected by the carrying out of that function.

[6] Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Acts in the case of Electricity Act functions.
[7] The Authority may have regard to other descriptions of consumers.
[8] Or persons authorised by exemptions to carry on any activity.

1.12. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[9] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[9] Council Regulation (EC) 1/2003.

Appendix 2 - Glossary

A

Authority

The Gas and Electricity Markets Authority

D

DECC

Department of Energy and Climate Change

I

IDC

Interest During Construction

ITT

Invitation to Tender

M

MW

MegaWatt

MVA

MegaVoltAmpere

R

RRE

Robin Rigg East

RRW

Robin Rigg West

P

PTRA

Post Tender Revenue Adjustment

Q

QTT

Qualifcation to Tender

S

SCADA

System Control and Data Acquisition

T

TR1

Tansitional Tender Round 1