Guidance

DRAFT - Offshore Transmission: Guidance for Cost Assessment (2026)

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Overview

Under the regulatory regime for the construction and operation of offshore transmission assets, Ofgem runs a competitive tender process to select and license Offshore Transmission Owners (OFTOs). To facilitate the tender process, Ofgem undertakes a cost assessment of the offshore transmission assets developed and constructed before they are transferred to the appointed OFTOs.

This guidance document sets out the cost assessment process that we follow to determine the transfer value for offshore electricity transmission projects developed and constructed by developers. It describes our approach for determining the economic and efficient costs of offshore transmission assets and provides developers with an overview of the information we require at each stage of our assessment.

This guidance has been updated to include further developments, best practice and lessons learnt since the previous version of this document was published in 2022. This update has been informed by a series of workshops with stakeholders and experience gained in executing offshore project assessments up to, and including, Tender Round 13.

Contents

Executive Summary

The Offshore Transmission Owner (OFTO) regime was established in 2009 to introduce competition into the delivery, financing, ownership and operation of offshore electricity transmission assets. Under the regime, transmission links connecting offshore generation projects to the onshore electricity network are transferred to an OFTO following a competitive tender process run by Ofgem, which ensures compliance with the ownership unbundling framework whilst driving cost and delivery efficiency.

The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015[1] (the **Tender Regulations**) govern how we run the Tender Process and grant offshore electricity transmission licences to Offshore Transmission Owners (OFTOs). This process includes assessing the economic and efficient costs of developing and constructing offshore transmission assets.

OFTO projects are constantly evolving, driven by:

- new technologies, which enable increased productivity and allow developers to build projects larger and further offshore
- market conditions which fluctuate in response to supply and demand
- regulatory updates, such as the introduction of Anticipatory Investment policy or the clarification of the End of Tender Revenue Stream process

This guidance document has been updated to reflect the evolving OFTO market, incorporate developer feedback gathered through Ofgem–industry bilateral workshops and a public consultation, and draw on Ofgem's experience in conducting cost assessments.

This document is to update stakeholders on our approach to cost assessment for offshore transmission. We have previously published Cost Assessment Guidance (CAG) in 2012, 2017, 2019, and 2022,[2] and much of the guidance contained in this document was also covered in the previous CAGs. The main changes to this guidance are to the following areas:

- Stages of the offshore transmission cost assessment process (see paragraph 2.9 to 2.40 and Appendix 3)
- Assessment of Capex: allocation and accuracy of costs process (see paragraph 3.6 to 3.17)
- Spares process (see paragraph 3.53 to 3.60 and Appendix 5)

[1] The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015

[2] "Offshore Transmission: Guidance for Cost Assessment" Ofgem, 2012, "Offshore Transmission: Updated Guidance for Cost Assessment" Ofgem, 2017, "Offshore Transmission: Guidance for Cost Assessment (2019)" Ofgem, 2019, and "Offshore Transmission: Guidance for Cost Assessment (2022)", 2022.

- Early-Stage Assessment for Anticipatory Investment (see paragraph 3.87 to 3.96)
- Community funds for transmission infrastructure (see paragraph 3.99 to 3.109)
- Clean Industry Bonus (see paragraph 3.110 to 3.114)
- Allocation and assessment of Interest During Construction (IDC) (see paragraph 3.126 to 3.145)
- Extension of Tender Revenue Steam (EoTRS) (see paragraph 3.158 to 3.161)
- Costs incurred in relation to Connection Offers (see paragraph 3.163 to 3.171)

This guidance document has been produced to assist developers in their understanding of the offshore transmission cost assessment process, the key issues that have arisen to date and our approach to such issues.

This guidance is relevant to both ongoing and future cost assessments. We intend to keep this guidance and our approach to cost assessment under review to ensure alignment with policy developments in the offshore regime and to deal with project specific issues as they arise. We will continue to engage with stakeholders and consult as appropriate to ensure the regime remains fit for purpose.

1. Introduction

Context and related publications

1.1 In 2009, the Government introduced the regulatory regime for offshore electricity transmission to connect significant amounts of renewable offshore generation to the onshore electricity network (the **OFTO regime**).

1.2 OFTOs are appointed through a competitive tender process (the **Tender Process**). OFTOs are granted an offshore transmission licence (**OFTO Licence**) with a fixed revenue stream for a specified time.

1.3 From the outset, the OFTO regime has encouraged innovation and attracted new sources of technical expertise and finance, while ensuring that grid connections are delivered efficiently and effectively.

1.4 The Tender Regulations govern the Tender Process and provide that we must calculate the economic and efficient costs of developing and constructing offshore transmission assets.[3]

1.5 Where we have granted an OFTO Licence to a Successful Bidder, for a particular project, the value of the assets transferred to the OFTO is determined based on the cost assessment carried out by Ofgem. This transfer value is reflected in the revenue stream of the OFTO Licence.

Associated documents

1. The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015
2. Offshore Transmission: Tender Process Guidance Document

[3] See below at paragraphs 2.1 to 2.7 for further details.

2. The Cost Assessment Process

This section sets out the context for cost assessment within the regulatory regime for offshore transmission and the cost assessment process adopted for Generator Build projects (i.e. those developed and constructed by offshore generation developers).

The purpose of offshore transmission cost assessment

2.1 Ofgem runs the OFTO Tender Process in accordance with the requirements of the Tender Regulations. The Tender Process results in the identification of an offshore transmission owner and operator (the OFTO) to whom the we grant a licence for offshore electricity transmission (the OFTO Licence).

2.2 The Tender Regulations require us to determine the value of the transmission assets to be transferred to the OFTO (the transmission assets), by calculating the "economic and efficient costs",[4] which ought to be, or ought to have been, incurred in connection with developing and constructing the transmission assets for a qualifying project. Prior to the transmission of electricity, this calculation will take the form of an "estimate" of costs. This becomes the Indicative Transfer Value (ITV). Then as soon as reasonably practicable after the estimate and once we are satisfied that the transmission assets are available and have the information required, we carry out an "assessment" of costs.[5] This becomes the Final Transfer Value (FTV) of the assets.

2.3 We will also review submissions related to the Extension of Tender Revenue Stream (EoTRS). This will cover the Extension Revenue Stream (ERS) cost assessment where Ofgem will review the costs associated with ongoing operation of OFTO assets post the original regulated revenue period.

Regime overview

2.4 Developers may choose one of the following:

- develop and construct the transmission assets themselves and then transfer the completed transmission assets to the OFTO identified through the Tender Exercise (the Generator Build option)
- undertake detailed design and preliminary works, but then defer the procurement and delivery of the transmission assets to the OFTO (the OFTO Build Late Competition option)

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[4] Regulation 4(1) (Calculation of costs incurred in connection with transmission assets) of the Tender Regulations.
[5] Regulation 4(2) of the Tender Regulations.

- defer the detailed design, preliminary works, procurement and delivery of the transmission assets to the OFTO (the OFTO Build Early Competition option)

2.5 The cost assessment process for each of these three build options is different. In the case of both OFTO Build options, it will be based on the economic and efficient costs of works carried out prior to the OFTO being selected, and in the case of Generator Build, it is based on the economic and efficient costs of developing and constructing the transmission assets. However, the principles applied to assess the relevant economic and efficient costs are similar.

2.6 As all developers have so far utilised the Generator Build option, this guidance document is focused only on the cost assessment process for that model. In relation to OFTO Build, we will update this guidance after further policy work and consultations are completed on OFTO Build options.

Purpose of this document

2.7 The Tender Regulations do not stipulate how we should calculate the economic and efficient costs of developing and constructing the transmission assets.

2.8 The purpose of this guidance document is to inform developers, and other interested parties, of our approach to offshore transmission cost assessment. As Ofgem completes more cost assessments, and to keep up with any regulatory updates or market changes, we will update this guidance in future to improve the cost assessment process. We will assess the need for a guidance update at the end of each tender round. We will continue to explore ways in which the regime can be improved, in consultation with stakeholders.

Stages of the offshore transmission cost assessment process

2.9 The developer-facing cost assessment process is conducted by us, in parallel with the Bidder-facing side of the Tender Process. Below, we summarise the stages involved in the cost assessment process and the points of interaction with the bid side of the Tender Process. A tabular illustration of the alignment between processes is contained in Appendix 1 to this guidance.

Initial Transfer Value (InTV)

2.10 To support the start of a Tender Exercise and as the first stage in the cost assessment process, we set the Initial Transfer Value (InTV). This is not the “estimate” of costs required under the Tender Regulations, but the developer’s initial estimate of how much it will cost to develop and build the transmission assets. We provide the developer with a pro forma cost assessment template

(CAT) in which to submit this cost information (see Appendix 2 for a detailed summary of the information required to be provided in the CAT).

2.11 The CAT is broken down into the following cost categories:

- offshore substation(s)
- submarine cable (incl. any interlinks)
- onshore cable
- onshore substation
- reactive substation(s)
- connection
- other
- transaction

2.12 Additional to the cost categories contained within the CAT are cash flow and foreign exchange (forex) sections. The cash flow section asks for the project expenditure to be broken down by month, alongside the IDC. The forex section asks for the major currencies that the project has utilised that are not in GBP and the exchange rate at financial close of those currencies against GBP.

2.13 We perform a basic review of the information submitted providing high-level feedback on the submission and a letter confirming the value.

2.14 The InTV is shared with bidders at the Enhanced Pre-Qualification (EPQ) stage of the Tender Exercise. The purpose of the EPQ stage is to identify a suitable shortlist of Bidders to proceed to the Invitation to Tender (ITT) Stage.

Indicative Transfer Value (ITV)

2.15 The next stage of the cost assessment process is setting the ITV. This is the "estimate" of costs that have been incurred or ought to be incurred.

2.16 At this stage, the developer submits updated cost information, upon which Ofgem carries out a detailed and robust review of the submission. With the support of its advisers, Ofgem also carries out a forensic accounting review and, if required, a technical advisor's review.

2.17 The ITV must be completed before commencing the ITT stage. The ITV submission needs to occur at least 7 months prior to the issuance of a completion notice for the transmission assets.

2.18 The ITV is shared with bidders at the start of the Tender Process ITT Stage and the ITV letter published later alongside the section 8A Consultation. The outcome of the ITT Stage is the identification of the Preferred Bidder for the Qualifying Project. Subject to satisfaction of certain matters prescribed in the Tender Regulations and as notified by Ofgem, the Preferred Bidder will become the Successful Bidder and ultimately the licensed OFTO. Qualifying Bidders at the ITT Stage use the ITV as an assumption for the Tender Revenue Stream (TRS), which they bid to own and operate the transmission assets.

2.19 Project costs are agreed at the ITV stage and should remain unchanged at the FTV stage unless a material change arises, such as refinement of estimates into actual costs, the occurrence of previously unaccounted-for cost overruns or any new costs.

Detailed submission review

2.20 This considers whether the estimated costs for the transmission assets are economic and efficient.

2.21 We do this by reviewing the cost information in the CAT, reviewing:

- Any variations to the original contracts that have arisen or are expected to arise during construction of the assets
- The allocations for any shared costs
- Any forecast costs
- Any further details requested in a Supplementary Questions (SQ) process

2.22 Following this review, we discuss any issues with the developer, to inform our consideration of whether the estimated costs have been incurred in an economic and efficient manner.

Forensic Accounting Review

2.23 The accounting exercise entails a review of the developer's contracts for the development and construction of the Transmission Assets. The contracts are checked against the details provided at the InTV stage, and the proposed cost allocations between the Generation Assets (which are excluded from the cost assessment), and the Transmission Assets is reviewed.

2.24 This review is carried out by our forensic accounting advisors and is typically carried out over two to three months as part of the ITV review.

Technical Review

2.25 The technical review typically focuses on two aspects:

- Reviewing the overall design of the Transmission Assets, including features such as the choice of electrical design, procurement efficiency, risk logs and the technology options evaluated.
- The main purpose would be to ensure the project design is functionally appropriate for the connected generation. Where the design is considered inefficient, we will discuss our concerns with the developer when assessing whether the transmission asset costs are economic and efficient.

Final Transfer Value (FTV)

2.26 The next stage of the cost assessment process is setting the FTV. This is the "assessment", referred to in the Tender Regulations, of the costs incurred for developing and constructing the Transmission Assets. It is the amount to be paid to the developer by the OFTO for the transmission assets.

2.27 At this stage, the developer submits updated cost information, upon which Ofgem carries out a detailed review of cost movements. With the support of our advisers, we also carry out a forensic accounting review and, if required, a technical adviser's review.

2.28 The trigger point for starting this assessment is 5 months prior to the appointment of the Preferred Bidder. Delaying the assessment may result in assets not being divested before the end of the 27-month Generator Commissioning Clause (GCC) period.[6]

2.29 If we delay the assessment process until all project spend has been incurred, the process to transfer the Transmission Assets and the grant of the OFTO Licence could be unnecessarily delayed.

Cost movement review

2.30 This review focuses on variations in costs from those estimates agreed at the ITV stage, assessing whether they are economic and efficient.

2.31 We request further detail in an SQ process.

Forensic Accounting Review

2.32 The accounting exercise consists of:

- checking that the contracts presented by the developer at the ITV stage have been performed
- examining the developer's bank statements in order to reconcile stated contract costs with actual payments

2.33 This review is carried out by our forensic accounting advisors and is typically carried out over two to three months as part of the FTV review

[6] The Generator Commissioning Clause (GCC) establishes a time-limited commissioning period—now 27 months from the issue of the completion notice—during which a generator may lawfully operate offshore transmission assets without a licence, for the purposes of commissioning and transferring those assets to an Offshore Transmission Owner.

Technical review

2.34 This review focuses on any design changes that have occurred since the ITV stage.

2.35 The main purpose would be to ensure the project design remains functionally appropriate for the connected generation. Where the design is considered inefficient, we will discuss our concerns with the developer when assessing whether the transmission asset costs are economic and efficient.

Closing the Cost Assessment process

2.36 Following this assessment, Ofgem sends the developer a draft cost assessment report, setting out the assessed transfer value (the FTV) of the transmission assets. This gives the developer the opportunity to correct factual errors and propose redaction of any commercially sensitive information.

2.37 The draft report is also sent to the Preferred Bidder, so that they can factor the FTV into their TRS calculations. The TRS amount, incorporating the assessed transfer value, is then published in a consultation pursuant to section 8A of the Electricity Act 1989, by which we propose modifications to the standard conditions of the OFTO Licence on a project-specific basis (the **section 8A Consultation**). We refer to this as the "**s8A TRS**", which is adjusted at licence grant to result in a final TRS amount payable to the OFTO under, and in accordance with, its OFTO Licence.

2.38 The draft cost assessment report is published alongside the section 8A Consultation. The report remains in draft form until the section 8A Consultation has concluded and we have determined to grant the OFTO Licence to the Successful Bidder. After Licence Grant, the final cost assessment report containing the FTV is published on the Ofgem website.

2.39 In each Tender Exercise completed so far, Ofgem has finalised the assessment of costs (the FTV) prior to commencement of the section 8A Consultation, and the s8A TRS has reflected 100% of the FTV. Where it is not possible to finalise the FTV in time for starting the section 8A Consultation:

- The s8A TRS would instead reflect the ITV and we would use the Post-Tender Revenue Adjustment (PTRA)[7] term at Licence Grant to adjust the tender revenue stream to account for 100% of the FTV

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[7] The Post-Tender Revenue Adjustment (PTRA) is the licence mechanism used at licence grant to align the Tender Revenue Stream with **the Authority**'s final assessed transfer value.

- If, under exceptional circumstances, this is not possible, we may adjust the TRS to reflect the difference (if any) between the ITV and the FTV upon conclusion of our cost assessment after Licence Grant. Again, we would use a PTRA term after Licence Grant to adjust the tender revenue stream to reflect the FTV

Timely provision of data throughout the process

2.40 Under the Tender Regulations, we can require a developer to submit further information to assist cost assessment calculations. Where we request further information, we indicate a date by which that information is to be provided. Where a developer fails to submit the information by the required date, we may decide not to take into account the information provided when determining both the ITV and/or the FTV.

3. Cost Assessment Approach

In this section, we describe the approach we use for assessing the ITV and FTV of Generator Build projects. We explain how we consider the allocation, accuracy and efficiency of costs components of the following main categories: capital expenditure, other costs, Interest During Construction (IDC) and transaction costs.

Introduction

3.1 The cost assessment process analyses developer cost submissions across four broad cost categories:

- capital expenditure
- other costs
- interest during construction
- transaction costs

3.2 Our assessment considers costs incurred in connection with the development and construction of the transmission assets and any forecasted costs up to completion.

3.3 Below is the description of the cost assessment approach for each of the above cost categories. We also comment on taxation issues at the end of this section.

Capital expenditure (Capex)

What do we mean by Capex?

3.4 The development and construction of the transmission assets require developers to enter into a variety of design, delivery, construction and installation contracts. Typically, the assets that are constructed are:

- offshore platforms
- the high voltage electrical power systems on the platforms
- subsea export cables
- onshore export cables
- onshore substations
- associated apparatus

3.5 We define Capex costs as all the costs involved in the development, design, delivery, construction (including civil works), installation, and commissioning of assets associated with the project's transmission system.

Assessment of Capex: allocation and accuracy of costs

General treatment of allocations

3.6 Capex must be allocated correctly (i) according to the different costs categories set out in the CAT provided to the developer (see paragraph 3.7 below) and (ii) apportioned between transmission assets and Generation Assets in accordance with an allocation methodology established by the developer (see paragraph 3.9 below).

3.7 To support capital cost assessment at the ITV and FTV stages, we provide the same CAT as at the InTV stage, setting out cost categories for different elements of the Transmission Asset (see Appendix 3 and paragraph 2.10). Developers should ensure that costs are correctly attributed to their appropriate category and minimise the use of the "other" category.

3.8 Where costs can be clearly attributed to either Generation or transmission assets (for example, based on purchase orders or invoices), the developer should allocate them entirely to that relevant asset.

3.9 Where project components are jointly procured, i.e. for both Transmission and Generation, the developer should clearly identify all costs associated with the assets being used for generation purposes and allocate these as a Generation Asset. It is important that these costs are apportioned appropriately so that there is no undue cross subsidy of the transmission elements by the generation elements, or vice versa.

3.10 The developer should establish a set of consistent rules for how to allocate costs. We would expect that this allocation methodology, developed and adopted by a developer, is sufficiently objective and transparent that it can be independently replicated and verified.

3.11 Allocation methodologies should be, as far as possible, based on the work carried out, the metrics used should be clearly defined and assumptions justified. Developers may discuss their proposed methodologies and underlying rationale with us ahead of any cost submission. Once any allocation methodology is agreed, we will crosscheck that the allocation of costs accurately reflects the methodology.

3.12 If a developer is unable to provide a metric and has based allocations on an estimate, or we do not consider that a clear, transparent and appropriate allocation methodology has been used, we may:

- allocate these costs based on an estimate of the percentage of transmission assets' cost versus the total costs of the project (including both Transmission and Generation Assets), and/or
- decide to either impose a metric or exclude elements of those costs from the transfer value

3.13 However, in either case we will discuss options with the developer to give them the opportunity to provide substantiation of their estimate(s) or methodology.

3.14 Occasionally, the procurement of generation assets and transmission assets as a package may lead to manufacturing discounts. In such instances, we would expect the discount to be allocated appropriately between the generation and transmission elements of the project. Where discounts are tied across several different projects (e.g. bulk purchase deals), we would expect an objective and justified allocation of the savings across those projects so that there is no cross subsidisation.

3.15 Where insurance policies are procured to cover the project as a whole, it will be necessary to identify the cost allocation between the transmission and generation assets. In the absence of any metrics supplied by the developer that are considered appropriate by Ofgem, we may revert to a percentage of cost related to the transmission assets versus the total costs of the project.

3.16 Where projects have been acquired from another party, the total acquisition cost paid by the developer may include aspects related to both generation and transmission. Only the costs that relate to the development and/or construction of the Transmission Asset (and their associated financing costs, which are assumed to be included in the acquisition cost), may be included in the FTV. This may require the developer to use an appropriate allocation metric to split such costs between transmission and generation. The developer should not include any profit, premium or goodwill, which forms part of the acquisition cost, as such elements reflect the value of the generation capacity rather than the transmission component.

3.17 Where additional costs are incurred on a shared asset, the developer should identify all incremental costs associated with the asset's use for generation purposes and allocate these as generation asset costs. Such allocations may be determined using bespoke metrics, where appropriate. Historically, examples include allocating the cost of additional structural requirements for generator-retained equipment on an offshore platform based on weight, or apportioning fibre-related costs according to the number of fibres utilised by the generator.

OSP assets supporting generation activities (e.g. helidecks, array switchgear)

3.18 A developer may request to retain the ownership of some offshore substation platform (OSP) assets, such as helidecks, array switchgear and/or Supervisory Control and Data Acquisition (SCADA) equipment. In this case the developer should account for this in the allocations described in 3.17.

3.19 Additionally, if we consider that there is evidence that suggests that the need for any assets on the OSP is driven by the requirements of the developer rather than the OFTO. Where this is the case, we will determine the costs associated with of the assets that generator should retain and the costs associated with their impact on the cost of whole OSP, including the topside, jacket/monopile and any associated foundations. We will come to a view (informed by submissions from the developer) as to the appropriate value to be included in the ITV/FTV.

Onshore substation areas supporting generation activities

3.20 A developer may retain the ownership of some areas in the onshore substation, such as control rooms, communications racks and/or SCADA equipment. In such cases, we will determine the costs associated with their impact on the cost of the whole onshore substation, including the building structure, foundations and wider groundworks for the whole site. We will then deduct a portion of these costs from the ITV and FTV to represent the space occupied by the developer (if the developer has not made an equivalent adjustment). Usually this will be done on a square metre area occupied basis but will be dealt with on a case-by-case basis.

Fibre optic cables for generation related activities

3.21 Fibre optic cables are installed alongside the onshore and offshore export cables for offshore projects. These are used for transmission control, generation control, monitoring and communication purposes. As the fibres used for generation purposes are not available to the OFTO, the OFTO gains no benefit from them.

3.22 We will assess the economic and efficient costs associated with the fibre optic system. We expect the developer to provide a breakdown of fibres showing the number that are transmission dedicated (including Distributed Temperature Sensing), generation dedicated and any spare fibres. Spare fibre costs should be distributed between OFTO and Generator on a pro rata basis.

3.23 If the developer has not done so already, we will make an adjustment for the whole costs associated with supplying and installing these fibres, for both on and offshore cables.

Assessment of Capex: efficiency of costs

3.24 In paragraphs 3.25 to 3.116 below, we set out a number of elements which we assess to determine whether the Capex costs are economic and efficient:

- Approaches to procurement and contract management (paragraphs 3.25 to 3.35)
- Project management costs (paragraphs 3.36 to 3.41)
- Treatment of contingency (paragraphs 3.42 to 3.44)
- Cable surveys and risk assessments (paragraphs 3.45 to 3.48)
- Interlinks (paragraphs 3.49 to 3.50)
- Vessels (paragraphs 3.51 to 3.52)
- Spares (paragraphs 3.53 to 3.60)
- Operational faults (paragraph 3.61)
- Land costs (paragraphs 3.62 to 3.63)
- Connection costs (paragraphs 3.64 to 3.65)
- Insurance (paragraphs 3.66 to 3.70)
- Hedging of exchange rates and commodities (paragraphs 3.71 to 3.79)
- Outstanding costs (paragraph 3.80)
- Treatment of cost overruns (paragraphs 3.81 to 3.83)
- Capitalisation of operating costs (paragraph 3.84)
- Depreciation of operational projects (paragraph 3.85)
- Anticipatory investment and wider network benefit investment (paragraphs 3.86 to 3.98)
- Community funds for transmission infrastructure (paragraphs 3.99 to 3.109)
- Clean industry bonus (paragraphs 3.110 to 3.114)
- Disruptive events (paragraph 3.116)

<u>Approaches to procurement and contract management</u>

3.25 Efficient procurement processes can make a significant contribution to cost control. In assessing whether costs are economic and efficient, we will review the developer’s approach to procurement and contract management for the main items of expenditure associated with the transmission assets. Developers should provide appropriate documentation demonstrating the processes followed and a clear justification of the outcomes achieved.

3.26 Developers have adopted a range of contracting approaches, including alliancing, wrapped contracts, use of internal resources, group level procurement and turnkey arrangements. Ofgem does not prescribe a preferred approach; however, developers must demonstrate that the chosen approach results in economic and efficient costs.

3.27 Where turnkey or wrapped contracts are used, we expect developers to explain the rationale for the approach. For example, a higher initial cost under a turnkey contract may be acceptable if it is offset by reduced project risk or lower downstream costs.

3.28 In all cases, developers must provide sufficiently disaggregated cost data to allow meaningful assessment. This includes a clear breakdown of total contract costs mapped to the cost categories set out in the Cost Assessment Template (CAT). Developers are expected to manage contractors effectively throughout the project lifecycle. This includes putting in place appropriate project management and contract control processes at the outset (i.e. prior to contract award) and maintaining these throughout delivery.

3.29 Where acceleration costs are incurred (for example, to expedite works or compress project schedules), we would not normally expect such costs to be included in the transfer value unless it can be clearly demonstrated that they represent an economic and efficient approach.

3.30 Developers should be able to evidence how cost and contract controls have been implemented and monitored. Where ineffective contract management contributes to cost increases, we may determine that such costs are not economic and efficient and may not include them.

3.31 Where developers propose to use single-source procurement, they should explain why competition was not feasible, demonstrate that the approach delivers value for money, and provide supporting evidence. Developers proposing this procurement strategy should engage with Ofgem at an early stage, in advance of main contract award, to discuss the proposed approach. Illustrative examples of acceptable evidence are set out in Appendix 4.

3.32 Where additional costs arise due to contractor underperformance or failure, developers are expected to seek recovery through contractual mechanisms rather than through the cost assessment process.

3.33 Where a settlement has been reached, developers should provide a clear explanation of:

- the basis of the claim
- the assessment of damages
- the contractor's proposed value
- the final settlement and how it was reached

3.34 Where settlements relate to both generation and transmission elements, the developer must justify the methodology used to allocate costs between them.

3.35 Recovered amounts may be reflected as adjustments to the FTV. Where claims remain unresolved at the time of assessment (e.g. prior to section 8A consultation), we may include an appropriate adjustment in the FTV based on the available evidence.

Project Management (PM) costs

3.36 PM costs can be divided into:

- PM costs directly attributed to each cost category in the CAT (direct PM costs), and
- PM costs that relate to the entire project and that will therefore sit within the "other" cost category in the CAT. These types of PM costs must relate only to the transmission assets (end-to-end PM costs).

3.37 Both direct PM costs and end-to-end PM costs will be evaluated during the cost assessment process.

3.38 When assessing PM costs, we will take into account the characteristics of the specific project. For example, for a project that utilises a multi-contracting strategy, we would not, based on the historical levels seen for past projects, expect direct PM costs to typically exceed 10% of Capex. For each costs category, we will compare direct PM costs against Capex costs (net of direct PM) and calculate the average across all cost categories. End-to-end PM costs are evaluated as part of the Development costs (see below at paragraph 3.118). In a turn-key approach part of the PM costs are included in the developer's contracts and we consider the overall amount of PM costs should be considerably lower when compared to Capex, again, based on our experience of past projects.

3.39 For all internal costs (including PM), developers are required to submit details of:

- the roles of personnel involved
- the activities undertaken
- applicable day rates
- the number of days (or percentage) allocated to transmission activities relative to the total project (non-transmission related activities)

This information will be required to substantiate any claims for such costs.

3.40 Developers should ensure that any personal data included in such submissions is limited to what is necessary for the purposes of cost assessment and is provided in accordance with applicable data protection legislation, including the UK General Data Protection Regulation (UK GDPR). We do not require the submission of personal information relating to individuals.

3.41 Any mark-up, margin or profit on such internal resources will not be accepted into the transfer value, as only costs incurred on an at-cost basis should be included.

Treatment of contingency

3.42 For projects still in the design or construction period, developers' cost data forecasts for the InTV and/or the ITV have may include contingency amounts to deal with future uncertainty over the actual cost and timing of construction.

3.43 We expect developers to have a methodology in place for establishing this contingency amount and to be able to explain this to us. Part of this process would usually involve a review of the relevant project's risk log.

3.44 Before the completion of the FTV cost assessment process, the transmission assets should be available for use for the transmission of electricity. There will be no contingency costs remaining within the FTV. If there are outstanding costs or costs in dispute when we are setting the FTV, we will come to a view (informed by submissions from the developer) as to the appropriate amount of these costs to be included in the FTV.

Cable surveys and risk assessments

3.45 A number of projects have experienced cost overruns related to the cable installation process and developers may seek to include such cost overruns. The reasons for cost overruns are numerous and relate to, amongst other things: technical difficulties, bad weather and 'waiting on weather' costs. However, an emerging theme in such cases is the extent and quality of seabed surveys and risk assessments undertaken by the developer, or its contractor(s), prior to the cable installation process which can assist with efficient and timely installation. We understand from developers that the information obtained from cable surveys and risk assessments is relied upon in determining which cable laying equipment is used during the installation process.

3.46 We will examine any cable installation cost overruns closely, with support from our advisers, as necessary. A key issue in determining whether these costs are permitted is to understand the steps and actions taken by the relevant developer to mitigate the likelihood of cost overruns. The question of whether or not to undertake detailed seabed surveys is a commercial decision for each developer. Where a developer decides not to do so, it is liable for the costs that may arise from that decision.

3.47 Developers should provide evidence that sufficient pre-installation risk assessment and mitigation procedures are in place, prior to the start of the cable installation works. A submission of the project's risk register would normally form an integral part of the evidence base. If, after investigation, it is shown that costs are attributable to inefficient pre-installation risk assessment procedures or mitigation procedures, then these costs will not be allowed in the ITV or FTV.

3.48 There are currently variations in the approaches and standards used by developers when commissioning geophysical studies, geotechnical investigations and cable route assessments. A publication by the Offshore Wind Programme Board recognised that effective surveys could reduce the risks and costs associated with cable installation.[8] This publication highlights good practice for marine survey activity, and we suggest that this is reviewed and followed by developers. This should create greater consistency across the industry and improve standards, which may reduce the level of risk priced in by OFTO bidders. This could also reduce the risk of project delays resulting from insufficient information on cable burial conditions.

Interlinks

3.49 An offshore interlink is a circuit which connects two (or more) offshore substations that are connected to a single common onshore substation. It is held in open standby until there is a transmission fault that limits the developer's ability to export electricity to the onshore substation. It is possible that such an interlink could connect two different projects owned by two different OFTOs, though so far, they have all been connecting offshore substations from the same project.

3.50 Following our approval of the Connection and Use of System Code (**CUSC**) modification Proposal CMP242,[9] the costs attributable to the interlink need to be separable from the remainder of the system for transmission network charging purposes. We expect interlinks to be costed up separately from the remainder of the project, with project management, etc, allocated appropriately.

Vessels

3.51 A variety of vessels will be required as part of the works associated with the installation of a project's subsea cables and offshore platforms.

3.52 We expect the developer to choose the appropriate vessels to undertake these works and to be able to provide evidence to us to justify vessel choices, in particular in relation to the selection of jack-up and cable installation vessels. Evidence such as a cost benefit analysis should be provided to justify the inclusion of economic and efficient costs of such vessels.

[8] See "Overview of geophysical and geotechnical marine surveys for offshore wind transmission cables in the UK", Offshore Wind Programme Board, September 2015

[9] "Connection and Use of System Code (CUSC) CMP242: Charging arrangements for interlinked offshore transmission solutions connecting to a single onshore substation", published on 10 February 2016

Spares

3.53 Where spares for the transmission assets are proposed to be transferred to the OFTO, we will consider including the economic and efficient costs of such spares in the FTV. Spares included in the transfer value should relate directly to the transmission assets and form part of the assets transferred to the OFTO. Developers should consider the procurement of spares early in the project design in order to achieve economic and efficient costs.

3.54 Developers should provide a comprehensive list of spares to be transferred to the OFTO and justify why such spares are required during the ITV review. This justification will depend on the role and function of each spare within the system.

3.55 We apply a structured classification of spares to support this assessment. The spares classes are described in Table 1, with further detail provided in Appendix 5.

Table 1 Spares Classes and their definitions

Spare Class	Category	Definition
1	System Critical Strategic Spares	Spare items that are fundamental to achieving the minimum availability target. Without these spares, the system would be expected to breach the availability requirement when exposed to credible failure scenarios.
2	High-Impact Long Lead Spares (bespoke main plant item products)	Spare items that are not strictly required to meet the availability target, but which significantly reduce the duration and impact of outages where replacement lead times or access constraints are material.
3	OEM Modular / Replaceable Strategic Sets	Spare sets forming part of planned replacement cycles or modular repair strategy. Spare holdings that support a defined modular replacement or repair approach, enabling restoration of service through component substitution rather than in situ repair, forming part of a structured maintenance philosophy.
4	Major Plant Strategic Spares (Exceptional)	Large, high-value equipment spares where operational benefit is clear but economic justification is difficult. Spare items associated with low probability but high consequence failure events, where the impact of failure is severe, but occurrence is infrequent.

5	Resilience / Enhancement Spares	Spare items that improve availability beyond target but are not required to meet it. Spare items that enhance system resilience, flexibility, or performance beyond the minimum availability requirement.
6	Operational / Maintenance Stock (Non-Strategic)	Routine inventory used for ongoing maintenance and operations, not tied to asset transfer. Inventory required to support routine inspection, maintenance, and operational activities, without material impact on system availability.

3.56 We will assess the inclusion of spares on a case-by-case basis in line with the principles in this section, taking into account the specific characteristics of the project and the function of each spare within the system.

3.57 In doing so, we will consider a range of factors, including:

- the materiality of the spare to system availability and recovery from credible failure scenarios
- the likelihood and consequence of failure events
- the repair strategy and expected duration of outages in the absence of the spare
- manufacturing lead times and offshore logistical constraints
- the extent to which the associated risks are already mitigated through system design, for example through redundancy or parallel configurations

These considerations form part of our structured assessment framework, as set out in Table 2, which is used to evaluate whether the provision of spares represents an economic and efficient approach. The weight given to each factor may vary depending on the nature and role of the spare, and whether it is required to meet baseline system requirements or provides additional resilience beyond those requirements.

Table 2 Assessment tests and decision drivers

Assessment test	Cost Assessment question to answer	Evidence Required	Decision Driver
Transfer-asset test	Is the spare clearly part of the assets to be transferred to the OFTO and not post-transfer O&M stock?	Asset register, transfer scope definition	CAPEX vs OPEX distinction (making sure cost is not simply removed from CAPEX to Spare)

Availability-materiality test	Does the spare materially protect the availability target, supported by Reliability Availability Maintainability (RAM) sensitivity?	RAM sensitivity analysis	Critical vs non-critical
Repair test	Is the quantity tied to a realistic repair scenario, not a convenience allowance?	Failure mode analysis, outage modelling	Risk exposure
Lead-time /logistics test	Would absence of the spare create disproportionate downtime because of long manufacturing or offshore logistics?	OEM lead times, logistics analysis	Duration of outage
Redundancy / system design test	Has existing N-1 / parallel design already mitigated the risk?	Design philosophy (N-1, parallel systems)	Need for spare
Proportionality test	Is the cost proportionate to the avoided forced outage/outage exposure?	Cost-benefit analysis	Proportionality
Alternatives test	Could the same risk be mitigated more economically by redundancy, monitoring, framework contracts, repair strategy, or standardisation?	Options analysis	Efficiency
Evidence quality test	Is the submission backed by OEM data, project geometry, lead times, and sensitivity analysis? Or is it the contractual model the developer had to sign up to?	OEM data, modelling assumptions	Credibility

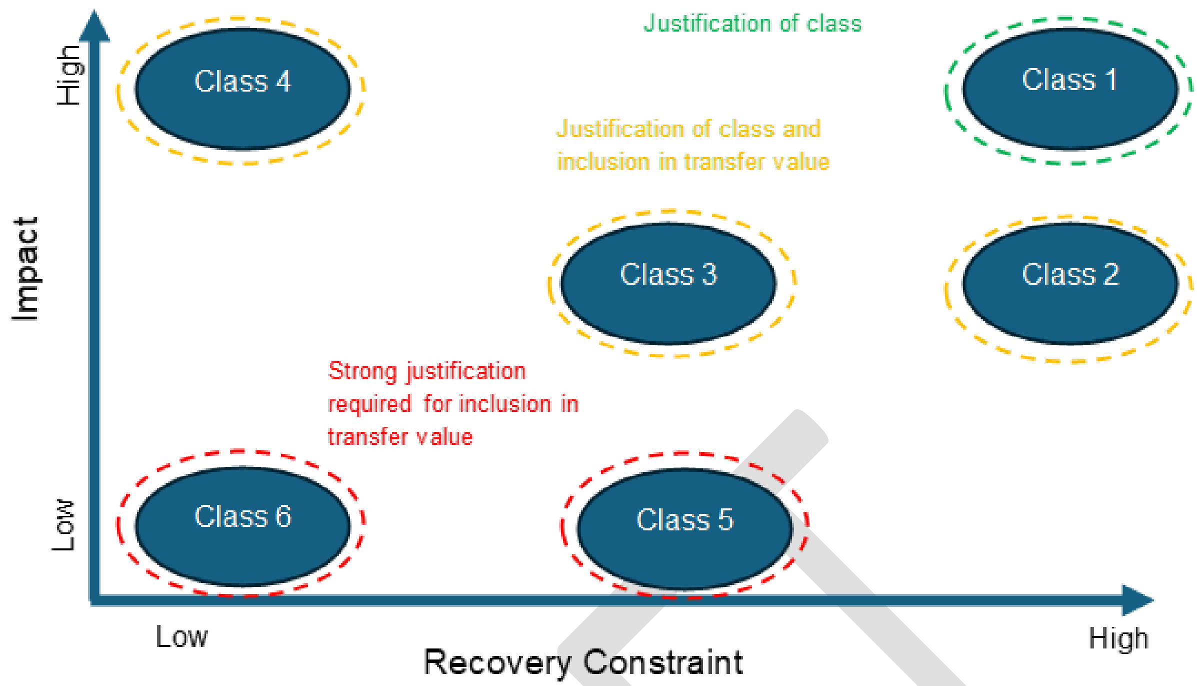

Figure 1: Evidence required by class

3.58 Figure 1 illustrates the classification framework used to assess spares based on their expected impact on system performance and the extent of recovery constraints. Spares are grouped into six classes, see Table 1 **Spares Classes and their definitions**, which are then assigned to one of three levels of evidential justification. Class 1 spares require justification of classification. Classes 2 to 4 require justification of both classification and inclusion in transfer value. Classes 5 and 6 require a stronger level of justification to demonstrate that inclusion in transfer value represents an economic and efficient approach.

3.59 Where spares are proposed for inclusion, developers should provide evidence sufficient to demonstrate that the provision of such spares represents an economic and efficient approach when compared to feasible alternatives. This may include supporting analysis such as reliability or availability assessments, repair and replacement strategies, and consideration of alternative mitigation measures.

3.60 We will consider whether the quantity and specification of spares are proportionate to the risks being mitigated, and whether the proposed level of spare provision reflects an efficient balance between upfront capital expenditure and operational risk. Spares that are considered to represent routine operational or maintenance stock, or which do not materially contribute to the efficient operation of the transmission assets, are not expected to be included in the FTV.

Operational faults

3.61 During the commissioning stage, the transmission assets are subject to various tests. Once energised and commissioned, the assets are considered to be available for the transmission of electricity, and the developer assumes full operational control for the system. A number of projects have experienced faults on the transmission assets post energisation and commissioning. In some cases, developers have sought to include the repair and associated costs in the transfer value. However, we will not include any of these costs since the Tender Regulations provide for the recovery of development and construction costs only, not those in connection with operational and maintenance activities.

Land costs

3.62 Offshore transmission systems require an onshore substation and overground/underground cables. Land is required to locate the substation and consents and easements are required for the land cable route. Developers either purchase or lease a plot to locate the substation, and purchase or secure lease agreements for the land cable. Typically, developers also need to compensate landowners for disruption caused by construction activities. We can consider including these costs up to the point of construction being complete, but not beyond that point into the operational period. Developers are advised to confirm their approaches for all of these activities and provide the appropriate documentation.

3.63 Developers have taken differing approaches in respect of the retention of land ownership, following transfer of the transmission assets. We do not have any preference as to whether land ownership is transferred with the assets or retained by the developer. However, if it is retained, we would expect the land lease costs, for use during the construction, development and operational periods, to be based on an evidenced (preferably market-based), open and transparent methodology. The duration of the lease costs allowed will match the duration of the TRS for that project only. Any additional lease costs after the TRS ceases will not be included. This principle will also apply to any seabed leases.

Connection costs

3.64 Developers will pay a charge for connecting up to the relevant onshore distribution or transmission network. Developers have had differing approaches to these costs; some have submitted these for inclusion in the transfer value, others have not.

3.65 We will review connection charge submissions on a project-specific basis. For each submission, we require the rationale for either including or excluding any such charges. Where included, we would also need justification for the level of economic and efficient costs to be included.

Insurance

3.66 We recognise that it is prudent for developers to procure insurance to cover events that may occur during construction. We, therefore, allow the economic and efficient costs of procuring insurance for the construction of the transmission assets in the FTV.

3.67 When determining what is an economic and efficient level of cost, we may compare the cost of insurance, on a specific project, against that which we have seen on comparable projects to date, taking into account market conditions and project specific issues. Insurance not related directly to the Transmission Asset is not economic and efficient.

3.68 It is the developer's responsibility to ensure that it has adequate and appropriate insurance to recover all costs in the event of an insurable event occurring. Therefore, we do not expect the developer to seek cost recovery through the cost assessment for costs that are either unrecovered or disputed from insurance claims.

3.69 If a claim arises, due to an event that occurred during the construction of the transmission assets, insurance deductible costs that are assessed as economic and efficient, will be allowed in the FTV. The cost of insurance deductibles, relating to claims made for incidents that occur after the transmission assets are operational, will not be allowed in the FTV.

3.70 In the event of multiple claims, the cost of each deductible will be allowed in the FTV, if each of these claims are incurred economically and efficiently and relate to incidents that occurred during the construction period.

Hedging of exchange rates and commodities

3.71 All costs submitted by the developer in the CAT should be in Sterling (GBP). Some contracts and resource costs will be in foreign currencies, and we recognise that developers will adopt different approaches for paying for these contracts. However, for the purposes of the cost assessment process, we adopt a methodology for converting foreign currency that assumes developers have hedged foreign currencies, irrespective of whether they have or not.

3.72 We apply two methodologies: one method at the InTV assessment stage, and a different method at the ITV and FTV assessments. For both methodologies, we use a suitable external reference, such as Bloomberg, for the applicable exchange rate data.

3.73 At the InTV stage, all foreign currency and commodity costs (including any variation orders) are converted either:

- using a single exchange rate per currency calculated using a suitable methodology proposed by the developer
- in the absence of the developer proposing a suitable methodology, using a single exchange rate calculated at a date identified by the developer which corresponds to when the majority of contract payments have been made or will have been made

3.74 For ITV and FTV assessments, we distinguish between 'firm' and 'uncertain' costs and may apply a different treatment to each, as set out below.

3.75 'Firm' costs refer to all foreign currency contracts and all foreign currency resource costs foreseen at the date at which the developer made the decision to go ahead with the project and funding was committed at Final Investment Decision (**FID**). For the purposes of determining the ITV and FTV, we assume that developers hedge all contract costs at or near the relevant contract signing date and all firm resource costs at or near FID. We use these dates to calculate a "blended rate" that will be applied to convert all of these costs into GBP. This blended rate is the average of the forward exchange rates corresponding to:

- The dates of significant contract payments, weighted by the volume of these payments
- The date profile of resource costs, weighted by the volume of these costs

3.76 Costs incurred before FID will be converted using the spot rate at the time that they were paid.

3.77 'Uncertain' costs refer to contingency, variation orders, and uncertain resource costs incurred in a foreign currency; these are costs which may be difficult or impractical to hedge. We expect the level of uncertain costs to be reasonable. For uncertain costs, we either:

- apply the same blended rate as for the firm costs to convert them to GBP
- at the developer's request, and with sufficient justification for its merit, convert all uncertain costs to GBP using the spot rates applicable at the time that the costs are incurred. This will require the cash flow profile of uncertain costs to be provided at InTV, ITV and FTV, with revisions made at each stage to take account of both the movements in spot rates and any time or volume changes in the spend profile

3.78 We assume that between InTV and ITV, or ITV and FTV, any increase or decrease in the total costs incurred in foreign currencies will be due to changes in uncertain costs. Therefore, any changes to total costs in foreign currencies will be incorporated into our assessment by adjusting the uncertain cost balance.

3.79 When a developer awards a contract, there may be a long duration until the contract is signed and the cost of the contract made firm. There may be an exchange rate true-up in the contract terms to cover any currency fluctuations over this period. If this is the case and there are indications that there will be significant period between contracts being awarded and being signed, we expect developers to take a hedging option to mitigate currency and commodity movements during this period. We consider this to be the most economic and efficient way to mitigate any losses.

Outstanding costs

3.80 When the cost assessment process is completed, cash payments made by the developer may not equal the FTV 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 (e.g. greater than 5% of the value of the transmission assets), we may delay our final assessment.[10] Where we consider that non-cash items are reasonable and do not amount to a significant percentage of the FTV, they will be treated as a firm commitment by the developer to allow the assessment to be completed.

Treatment of cost overruns

3.81 When significant construction cost overruns or variation orders arise, we expect developers to discuss these matters with us in a timely manner. In such circumstances, we may undertake an investigation, supported by our advisers, to inform our decision on whether submitted costs are economic and efficient and should be included in the FTV. We will consider each case on a project specific basis, as issues that arise may not be common across projects. To inform our decision-making, we may instruct our advisers to liaise closely with the developer, to assist us in understanding, amongst other things, the decisions and mitigating actions taken.

3.82 To facilitate conclusion of the cost assessment process in a timely manner, developers are advised to provide, as a minimum, the following supporting information:

- a detailed explanation of each cost overrun, including the root cause(s)
- a chronological order of events
- solutions considered and costs of those solutions

[10] If necessary, we could use the PTRA mechanism to avoid delays to the transaction (see paragraph 2.39).

- the preferred option, why it was chosen and the cost of that option
- the chosen solution(s) with technical justification (where relevant)
- the associated risk assessment
- whether the event was insurable
- details of claims and supporting board papers

3.83 Without this information, we may be unable to determine whether the costs are economic and efficient. This could cause a delay to the cost assessment process and exclusion of unjustified cost overruns in the FTV. Under the Tender Regulations,[11] where developers fail to provide information by a required date, we may decide not to take into account the information provided when determining the ITV or FTV.

<u>Capitalisation of operating costs</u>

3.84 We do not allow the capitalisation of operating costs as this is not within the scope of our OFTO cost assessment process. Operational costs are those costs that have been (or will be) incurred after the point at which the transmission assets are available for use for the transmission of electricity; examples include: operations and maintenance costs, fishery disturbance payments, land lease and easement payments, insurance costs, post-construction environmental monitoring, and storage of cable and equipment spares.

<u>Depreciation of operational projects</u>

3.85 The design life indicated by manufacturers for offshore transmission assets is generally greater than the OFTO's revenue entitlement period.[12] On this basis, although some projects may be operational for a period of time prior to the transmission assets being transferred to the OFTO, we consider it reasonable not to apply depreciation to the assets' FTV. However, we will keep this under review and consider depreciation on a case-by-case basis.

Anticipatory and wider network benefit investment

3.86 The projects that have been through the cost assessment process to date have been simple radial (point-to-point) connections. However, some projects may support future offshore developments in relation to grid connection, which involves additional capability, within their Transmission Asset design, to connect future offshore generation projects, or provide wider network benefits. We consider two types of Anticipatory Investment, as follows.

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[11] Regulation 4(7) of the Tender Regulations.
[12] The revenue entitlement period for projects from TR1 to TR5 is 20 years. For projects included in TR6 and onwards, the revenue entitlement period is up to 25 years.

Early-Stage Assessment for Anticipatory investment

3.87 The purpose of this section is to provide guidance for cost assessment process undertaken as part of ESA process. For more information on Anticipatory Investment (AI) and the ESA please refer to the Early-Stage Assessment Guidance Document.[13]

What do we mean by Anticipatory Investment?

3.88 We use the term 'Anticipatory Investment' to refer to investment in offshore transmission infrastructure to support the later connection of a specific offshore development or developments. This is investment which goes beyond the needs of the immediate offshore development or developments.

3.89 We refer to the developer making the investment in the shared asset as the 'applicant(s).' We refer to the developer or developers that will use the shared asset in the future as the 'later user(s)'.

Assessment of Anticipatory Investment: Information required

3.90 The cost assessment requires the applicant(s) to provide a detailed account of the anticipatory investment being proposed alongside a specific set of criteria as set out in the Early-Stage Assessment Guidance Document[14] and forms part of the ESA Technical Assessment. This account should include:

- a breakdown of the associated cost of the proposal, which applicants have the option to resubmit at a later stage should they wish to. The costs submitted should specify which parts of the offshore transmission assets will be constructed for the benefit of an anticipated project (rather than wider project costs). In the case applicants choose to submit their cost breakdown at a later stage, they must still provide a high-level indicative cost as part of their Technical Assessment
- A detailed breakdown of contract, contingency and other costs, included in the cost submission
- a detailed timeline for both the applicant and later user through to energisation of the system showing project milestones
- a risk log which includes any risks which may have an impact on the development, construction and/or completion of the proposed coordinated solution

3.91 If the applicant is unable to provide the requested information, they must provide an explanation as to why, together with any supporting documentation which the

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[13] Early-Stage Assessment Guidance Document" Ofgem, 2023
[14] Early-Stage Assessment Guidance Document" Ofgem, 2023

applicant considers relevant. It is at our discretion to consider the application and decide whether to allow it to proceed and/or whether, and what, further information may be required.

Cost Review

3.92 The cost review will be conducted as part of the ESA process and follow the timescales for completing that process. The ESA cost review follows the same principles as set out in this Cost Assessment Guidance.

3.93 For costs to be considered eligible for recovery at licence grant for the applicant, the costs submitted must be evidence-based, with clear rationale for the costs included in the submission. Any shared work or assets being proposed must have any allocations clearly indicated with the methodology and the reasons for using that allocation explained in detail. The applicant is required to provide as much detailed evidence as possible to allow us to provide greater certainty that the costs will be recoverable through the cost assessment process.

3.94 A 10% threshold will be allocated to any underspend or overspend on any agreed costs. Should applicants submit costs in their final submission that the anticipatory investment portion is more than 10% above or below what was initially agreed at the ESA (or any later submission(s)), then all costs for the anticipatory investment will be subject to a full ex-post cost assessment.

3.95 In any assessment, these anticipatory investment costs will be subject to our standard forensic process of verifying that they were incurred economically and efficiently in constructing the part of the offshore Transmission Asset intended for use by the later user(s), as set out in the ESA and the actual amounts incurred. As described in paragraph 2.23 of this document.

3.96 The outcome of the cost review stage is to set out the anticipatory investment cost figure, which includes any interest during construction (**IDC**). The duration of the IDC on the assets will be determined by the actual construction timeline for the anticipatory investment assets.

<u>Developer-led Wider Network Benefit Investment</u>

3.97 In its current role of making connection offers, the independent system operator and planner (**ISOP**) may already request that a developer of offshore generation includes Wider Network Benefit Investment (**WNBI**) in its project if the SO believes this would support the economic and efficient development of the network.

3.98 We are not aware of any connection offers to date that include developer-led WNBI. However, where this is the case, we have previously proposed that we would carry out ‘gateway assessments’ to minimise the risk of consumers bearing the cost of ‘stranded’ transmission assets and to give developers comfort on their route to cost recovery for the developer-led WNBI included in their project. Through the gateway assessments, we would review the rationale for including the WNBI in the developer's project. If, under the gateway assessment, we consider that the WNBI would be in the interests of consumers, we would include the costs of WNBI in the cost assessment as part of a subsequent offshore tender. This provides the developer with confidence that they are able to recover the economic and efficient costs of the additional investments. For more information on gateway assessments, please see our latest conclusion document on the matter.[15] Where a developer receives a connection offer that includes developer-led WNBI, we encourage them to contact us to discuss the offer and the potential for a gateway assessment.

Community funds for transmission infrastructure

3.99 In November 2025, Department for Energy Security and Net Zero (**DESNZ**) introduced guidance[16] requiring transmission network project developers to allocate funds to community benefits, which are monetary and non-monetary benefits provided to enhance the economy, society and/or environment in the local area.

3.100 This applies to any onshore transmission infrastructure associated with and developed by offshore wind farms, including substations, converter stations and any overhead cabling. It does not apply to cable installed underground.

3.101 The DESNZ guidance sets out the government's expectation of the level of funding that developers should provide. Presented as a total sum rather than an annual payment, these are:

- £530,000 per substation
- £530,000 per converter station
- £530,000 per switching station
- £200,000 per km of overhead line

3.102 Developers are expected to fund delivery costs separately to the community fund itself. The guidance does not prescribe how much delivery costs will be as this will vary on a project-by-project basis; however, they are expected to be under 10% of the total cost of a community funds package unless exceptional circumstances are presented.

3.103 Both the recommended levels of community funds and the associated delivery costs are recoverable through the OFTO regime, if substantiated as economic and

[15] "Integrated Transmission Planning and Regulation (ITPR) project: final conclusions" Ofgem 17 March 2015
[16] "Community funds for transmission infrastructure", DESNZ 2025

efficient. As this is not mandated funding, we would expect developers to justify these costs, as economic and efficient, using the same cost benefit analysis methodology as used by DESNZ for these benefits.[17]

3.104 A non-exhaustive list of potential delivery costs includes (but is not limited to):

- Capacity building
- Feasibility work
- Staff costs
- Engagement
- Marketing
- PR costs
- Third-party administrator costs
- Governance costs

3.105 The monitoring and evaluation of the community fund itself should be established between the government and the developer and is not the responsibility of Ofgem. We therefore do not conduct a detailed review of the spending of community funds.

3.106 Ofgem's role is ensuring that effective governance arrangements are in place. The original developer of the transmission asset (i.e. the Generator in the case of Generator-build transmission assets) retains responsibility for the ongoing governance and oversight of the community benefit fund. Good practice requires that there is functional separation between the administrator of the community funds and the decision-making body that decides how available funding will be disbursed.

3.107 In order for the costs to be recoverable, developers must demonstrate that delivery costs have been built up from first principles. Resourcing costs should be itemised rather than based on fixed rates or percentages of overall project cost.

3.108 As spending on the delivery of community funds may take place after energisation or post-transaction, we accept forecasted costs here with a justified methodology. Evidence may include details such as day rates of staff, roles, and overheads.

3.109 As the community fund obligations relate to the transmission assets, we would expect costs to be entirely allocatable to the OFTOs. Any other allocation methodology will require a specific justification with appropriate evidence.

[17] Community Benefits for Electricity Transmission Network Infrastructure Government Response, DESNZ 2023, Page 47.

Clean Industry Bonus

3.110 The Clean Industry Bonus (**CIB**) is a Contracts for Difference (**CfD**) mechanism administered by the DESNZ. Generators may receive additional CfD revenue support under the scheme in respect of certain supply chain investments, these are known as 'CIB extra proposals'. Full details of the scheme, including eligibility, allocation and monitoring requirements, are set out in DESNZ publications, including the CIB Allocation Framework[18] and associated implementation guidance.[19]

3.111 CIB revenue support may relate to assets that form part of the offshore transmission system.

3.112 For the purposes of offshore transmission cost assessment, where a generator has received CIB revenue support in respect of OFTO-related components, cost submissions must be presented on a net basis. This requires the value of any CIB revenue support associated with those components to be deducted from the total costs submitted for the construction of the transmission assets, in order to avoid double recovery.

3.113 Where OFTO-related components form part of a generator's CIB minimum standard proposal and therefore are not in receipt of additional CIB revenue support, no action is required. Such costs should be presented in accordance with the standard offshore transmission cost assessment framework outlined in this guidance.

3.114 In assessing costs, Ofgem will take into account any CIB revenue support associated with OFTO-related components to ensure that submitted costs are appropriately netted. The presence of CIB does not otherwise alter Ofgem's approach to offshore transmission cost assessment.

3.115 Ofgem does not expect to see any costs submitted as a result of any shortfall in the CfD bidding process.

Disruptive events

3.116 Some developers have submitted additional costs associated with disruptive events, such as Covid 19. Our approach to these additional costs is the same as for any cost overrun (see paragraph 3.81); the developer must provide evidence that all options were explored to mitigate any additional costs and that the option

[18] Contracts for Difference Scheme for Renewable Electricity Generation Allocation Round 7: Clean Industry Bonus Allocation Framework, 2024
[19] Contracts for Difference (CfD) Allocation Round 7: Clean Industry Bonus framework and guidance

taken was the most economic and efficient approach available at the time. Additional costs in relation to disruptive events will be assessed on a case-by-case basis.

"Other" costs

What do we mean by "other" costs?

3.117 Before commencing the construction of transmission assets, the developer would usually undertake a front-end engineering design process, followed by a detailed process to obtain the relevant consents and permissions that are required for constructing assets offshore and onshore. For example, detailed surveys of the seabed will be required to ensure that the assets avoid existing apparatus or seabed wreckage, and detailed environmental impact assessments that will be required to satisfy statutory requirements. The onshore cable route for the transmission assets will require detailed planning to avoid existing assets (e.g. pipes, cables, roads and railway tracks); to take account of land conditions and in some cases special measures may be required to satisfy local planning arrangements. Obtaining the relevant consents will involve project management services and the use of specialist equipment and contractors. We generally refer to these costs as pre-construction development costs.

3.118 When the project enters the construction period, project management and some development activities will continue. End-to-end PM costs, as well as some development costs, are costs common to the entire project (including Generation and transmission assets) and are assessed as part of the development costs. Direct PM costs are included and assessed against the Capex costs in the relevant assets' costs categories.[20] The approach to managing the construction and day-to-day control of contractors has varied across developers; for example, some have project managed via in-house resources and others have outsourced project management or contracted out the supply and installation through a turnkey contract.

3.119 Through the cost assessment process, we will review the developer's historical and ongoing development costs. Set out below is an overview of the analysis that we will undertake to ensure that the total development costs, included in the cost assessment processes, are allocated appropriately, and are economic and efficient.

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[20] See paragraphs 3.36 to 3.37 for further details.

Assessment of "other" costs

Allocation to the cost categories

3.120 Development costs, end-to end PM costs and other end-to-end shared costs (like insurance and health and safety related costs) are reported in the CAT under the category "other".

3.121 Historically, developers have adopted different approaches to reporting their development costs. For example, some have reported ongoing project management within construction packages, while others have reported these at an aggregated cost level. Costs associated with specific elements of a project should be allocated to that package; for example, project management of the onshore substation work package represents a 'direct PM cost' and should be in the onshore substation cost category. End-to-end project management and other development costs (like consents) will be allocated to the "other" cost category. If costs associated with developing an asset are identifiable, we would expect the developer to allocate those costs to that asset. Where necessary, we will instruct developers to reallocate costs that have been incorrectly classified.

Efficiency of development costs

3.122 In calculating the FTV, we will review whether development costs are broadly in line with the range provided by our advisers. Where these differ markedly, we will undertake additional analysis to ensure that only appropriate development costs are allowed.

3.123 We have completed the cost assessment process for multiple offshore projects. We have found that, on average, resources costs (including development and end-to end PM costs) do not exceed 15% of Capex.

3.124 For some projects, we have capped the allowed resources costs at 15% of the allowed Capex. In the absence of any project-specific evidence that demonstrates the efficient development costs to be above this level, we will continue to cap development costs at 15% of the allowed Capex.

Interest during construction (IDC)

What do we mean by IDC?

3.125 IDC refers to the financing costs incurred by a developer in funding the development and construction of the transmission assets. Industry commonly recognises these financing costs as part of capital expenditure. For the purposes of the cost assessment, we consider IDC to be an efficient cost of capital during the development and construction period of the transmission assets. However, the IDC rate that we apply may not be at the same rate or for the same duration that a developer has actually incurred costs.

Allocation and assessment of IDC

Allocation of IDC

3.126 IDC is only applicable to the cash flow representing the actual allowed Capex and Development costs[21] associated with the transmission assets. When changes are made to the developer's submitted costs by re-allocation of costs to the Generation Assets or by assessing efficiency of the costs submitted, these will be reflected in the cash flow. This ensures that the IDC calculated for the transmission assets relates to the economic and efficient cost of developing and constructing the assets.

3.127 IDC is only allowed on the actual cash flow representing payments made against the contracts for developing and constructing the transmission assets. We do not apply IDC to accounting data as it does not represent the actual cash cost to the developer and may include non-cash elements such as retentions, accruals for work completed but not invoiced, unpaid invoices, any set-off amounts deducted and provisions. Ofgem recognises that IDC calculated under this approach may not mirror a developer's actual financing arrangements or interest accrual profile; however, for the purpose of cost assessment we apply IDC to an assessed "allowed cash flow" so that IDC is attached only to costs that are economic and efficient and attributable to the transmission assets. This ensures that the IDC calculated for the transmission assets relates to the economic and efficient cost of developing and constructing the assets.

3.128 IDC is applicable separately to each project and is not applied across multiple projects. See the section on Early Stage Assessment (**ESA**) for details on investments made in anticipation of future projects. The following principles apply to the treatment of IDC in this context:

- IDC will cease when work on the anticipatory investment(s) is completed and will not resume until construction recommences on those specific anticipatory assets as part of the subsequent project
- IDC will not accrue during periods of no active construction on the relevant transmission assets (or the specific anticipatory assets), not justified in line with paragraph 3.138

[21] For further information of what constitutes Capex and Development costs, see paragraphs 3.4and 3.118 to 3.120 of this document.

- For these purposes, a period of no active construction means there is no onsite or offshore installation, termination, commissioning of OFTO assets, or other demonstrable construction activity, as evidenced by the construction programme and supporting records
- IDC will only resume in relation to the specific anticipatory assets once those assets are back under active construction. It will not resume simply because the subsequent project has started construction more generally

<u>Efficiency of IDC</u>

3.129 The purpose of allowing developers to claim IDC is to recompense them for the economic and efficient costs of financing the development and construction of the transmission assets. The ‘economic and efficient’ test applies in respect of the rate of IDC allowed the period for which IDC is being applied and the costs for which IDC is attached; these are set out and discussed below.

Interest rate applied to the project

3.130 We calculate IDC on a pre-tax nominal basis. The use of a pre-tax rate ensures that developers adopt a rate that enables them to meet the expected level of tax in the chargeable gain which arises from the inclusion of financing costs in the assessed costs.

3.131 The level of IDC should reflect the average rate that the developer (or in the case of corporate supplied funds, its corporate sponsors) has incurred on the funds provided. Generally, the funds may come from providers of both equity and debt. The rate we allow is the rate that an efficient and economic transmission company engaged in this type of activity has (or ought to have) incurred. This is not necessarily the rate that has been incurred by a developer on the generation element of the Qualifying Project.

3.132 The developer must substantiate its claim for IDC with relevant documentation, for example evidence of the target discount rate approved for such projects, or the expected return, if lower. Such rates should include the quantum and rate from lower cost debt funding where obtainable. If we consider the rate proposed by the developer to be excessive, relative to its funding sources, we will assess the rate that should apply based on the weighted average of its funding sources.

3.133 We publish an annual decision on appropriate IDC rates. This allows developers that take FID for projects during that year. The IDC cap is fixed at the date of FID and applies for the efficient duration of construction until the transmission assets become available for use for the transmission of electricity. However, if we determine that a developer makes FID to lock in a favourable IDC rate and/or is not progressing a project at a sufficient pace beyond that point, we may adjust both the rate and the period of applicability to reflect those that would have applied if FID had been taken at the most appropriate point in time.

3.134 We will conduct an annual review of the cap to ensure that it remains responsive to market movements. It is important to note that changes arising from such reviews will not affect projects that have already reached FID. A decision to change the cap will be communicated prior to coming into force, following a consultation where appropriate.

Duration of the financing

3.135 The approach taken to each project will be specific to that project's arrangement of assets and we will discuss with the developer the IDC treatment for its project during the ITV stage. The IDC treatment will take into account the following guidance principles in the paragraphs below.

3.136 In general, IDC will cease as soon as transmission assets are available for use for the transmission of electricity to the onshore network. For larger and more complex projects this could mean that IDC ceases on part of the transmission assets but continues to be payable on a reduced portion of Capex corresponding to the transmission assets still under construction. IDC for this period is calculated by adjusting the IDC-earning capex balance using a proportion based on the cost of transmission assets under construction and the cost of transmission assets already available for use.

3.137 Transmission assets will be considered "available for use for the transmission of electricity to the onshore network" at the point at which we consider that those assets have been safely energised and commissioned i.e. the point at which the relevant transmission assets have achieved the necessary technical and system approvals to permit transmission of electricity to the onshore network in accordance with applicable ISOP and are capable of operating for their intended transmission function. This point will be project specific and may or may not align with the stages of the developer's construction programme and/or with the point at which a completion notice is issued to Ofgem for those transmission assets:

- IDC for a specific project will be determined with reference to the energisation and commissioning of the transmission assets only and not energisation and commissioning activities that are associated with the wind farm Generation Assets. There may be occasions where Transmission Asset and Generation Asset commissioning activities occur in parallel

- As a general rule, each time an offshore substation becomes available for use, we will consider the cables and other transmission equipment directly associated with that substation to also be available. Where a project has an interlink cable connecting different offshore substations, we may treat the energisation of the interlink as a signal that the interlink and associated substations connected to it have become available

3.138 IDC will not be allowed on assets that are not actively in the course of construction (see paragraph 3.128). For example, a cable may be ‘wet’ stored (left on seabed) for a period of time before being installed and terminated. Ofgem recognises that certain “quiet periods” (including wet storage) may be economic and efficient where they are a planned and evidenced part of the construction methodology. In such cases, IDC may continue to apply, provided the developer can evidence that the period is efficient, planned, and necessary for delivery of the transmission assets. If we consider this period to be inefficient or there is no construction activity occurring, we will adjust the IDC allowed to reflect this. This applies to all asset types, not just subsea cables.

3.139 Ofgem has determined that an economic and efficient pre-FID development period for non-acquired projects is typically around 53 months, based on evidence from previous OFTO developments and evolving regulatory requirements, and will keep this benchmark under periodic review. Where applying an assumed or benchmark development period (including for the pre-FID stage), developers must demonstrate that this appropriately reflects the project’s stage of development at entry into the regime. Where this is not evidenced, Ofgem may determine an alternative period based on the efficient development and procurement programme for the transmission assets.

3.140 For IDC on Anticipatory Investment (see 3.86), IDC will only apply to anticipatory investment while those specific assets are actively in the course of construction. IDC will not be included for the time period after the construction is completed and the resumption of construction activities, in line with the principles laid out above (as described in paragraph 3.139).

3.141 As projects have become larger and more complex, we have and will continue to refine the cost assessment process to ensure that any costs incurred and paid can be considered economic and efficient. We will consider the length of time over which IDC is applicable, and if we consider there is evidence of inefficient and uneconomic time periods during the pre-construction, construction or commissioning programme for the transmission assets, the period of IDC applicability may be adjusted to reflect this. Where the developer considers an apparent period of reduced activity to be efficient, it should provide contemporaneous evidence (e.g. programme logic, method statements, vessel schedules, interface registers, and correspondence with relevant parties) and a cost benefit analysis to demonstrate why the period was cost effective and efficient.

Eligible costs

3.142 IDC will not be applied to costs deemed to be inefficient and will also be curtailed in line with any Capex reductions made to the project.

3.143 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 should already reflect suitable remuneration for financing costs over that earlier development period.

Examples of Adjustments to IDC

3.144 In the case of a period were an asset not being actively in the course of construction, in line with the principles laid out in paragraph 3.136. We will request a disaggregated cashflow from the Developer, isolating the specific spend relating to the asset in question. We will then suspend the accrual of interest on the cashflow for the duration of the period of inactivity on that asset. Where the developer asserts that a period of limited activity (including wet storage) is efficient and forms part of an evidenced construction methodology, the developer should provide the evidence listed in paragraph 3.138 and a clear explanation of why IDC is applicable to the period in question.

3.145 In the case of different assets becoming available for use in a phased commissioning programme, the developer should either provide a disaggregated cashflow ending the accrual of IDC on each asset that is available or provide a calculation for the percentage completion for each asset, as it becomes available for the transmission of power.

Transaction costs

What do we mean by transaction costs?

3.146 Transaction costs relate to costs that a developer has incurred during, and as a consequence, of the Tender Process. These costs are generally reviewed at the FTV stage of the cost assessment process and include:

- tender fees payable to Ofgem
- the developer's internal and external costs as a result of the Tender Process

Assessment of transaction costs

Costs incurred by Ofgem's cost estimate exercise

3.147 Fees payable by the developer to Ofgem under the Tender Regulations[22] to cover Ofgem's costs in conducting the cost assessment process are recoverable as transaction costs.

3.148 Developers must pay Ofgem's tender-related costs in accordance with the Charging Schedule and payment instructions issued for the relevant Tender Exercise. Further detail is set out in Chapter 12 of the current Tender Process Guidance Document in accordance with Regulation 10 of the The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015.

Developer's internal and external costs

3.149 To support their activities in the Tender Process, developers may have had to utilise a range of resources or services including, for example, producing legal documents in connection with asset transfer or taking financial advice to support the cost assessment process. The developer's internal and external costs should not include activities that relate to generation activities.

3.150 We require developers to submit evidence to support the level of external and internal costs that they have submitted. These costs may be reviewed as part of the forensic accounting investigation.

3.151 For internal costs, developers are required to submit details of the roles of personnel involved, the activities undertaken, applicable day rates, and the number of days allocated to tender activities relative to the total project (non-tender related activities), in order to substantiate any claims for such costs.

3.152 Developers should ensure that any personal data included in such submissions is limited to what is necessary for the purposes of cost assessment and is provided in accordance with applicable data protection legislation, including the UK General Data Protection Regulation (UK GDPR). We do not require the submission of personal information relating to individuals.

3.153 Any mark-up, margin or profit on such internal resources will not be accepted into the transfer value.

3.154 There may also be internal specialised staff charged directly to the project for undertaking work directly related to the Tender Process, for example this could

[22] Regulation 5 (Payment of costs) of the Tender Regulations.

include engineers, accountants, etc. Where this is the case, we would similarly require appropriate evidence.

Taxation

Value added tax (VAT)

3.155 HMRC has 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**).[23] HMRC has 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 (e.g. 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.

Capital allowances

3.156 Each transfer of transmission assets from a developer to an OFTO under a Generator Build tender exercise is for a set of assets on an as-built basis, based on actual expenditure. We therefore assume for the cost assessment process that the OFTO, as purchaser, will obtain the full benefit of all available capital allowances.

3.157 Where benefits do not fully pass across and any such tax benefit is retained by the developer (e.g. as a result of agreement reached between the developer and the Preferred Bidder), which results in the OFTO 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.

Extension of Tender Revenue Steam (EoTRS)

3.158 EoTRS is the point at which an OFTO approaches the end of its initial TRS and Ofgem considers whether an Extension Revenue Stream (ERS) should apply so assets can continue operating where they remain economically viable[24].

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[23] Transfer a business as a going concern
[24] Guidance on offshore transmission health reviews - decision | Ofgem

3.159 Ofgem’s extensions framework is intended to avoid premature decommissioning of viable transmission assets, support continued carbon free generation, and deliver value for consumers.

3.160 By 5 years before the end of the TRS period (T-5), Ofgem expects the OFTO asset health review to be completed and shared with Ofgem, with the OFTO consulting the generator on scope and findings. At T-5, the OFTO should provide preliminary costs for (i) required investment works and (ii) extension-period operating costs, to inform Ofgem’s review and subsequent ERS bid development. Ofgem will assess the economic and efficient investment costs, including whether the scope is justified and costs are supported by robust evidence.

3.161 By 2 years before the end of the TRS period (T-2), Ofgem expects to implement the required licence modifications and the corresponding extension arrangements (where an extension is agreed). The investment works costs are recovered through an ex-post claims-based process and assessed against the economic and efficient test using actual cost evidence.

3.162 Where interim/partial awards are made, Ofgem may require repayment if the final approved amount is lower than the interim amount. Where the final approved amount is higher than any interim amount, Ofgem may consider an additional adjustment through the same assessment and approval approach i.e., a top-up. This will be subject to a review of supporting evidence and Ofgem’s assessment of the actual costs incurred.

Costs incurred in relation to existing OFTO connection offers

3.163 Under Standard Licence Condition E17, an OFTO is required, when directed through the ISOP framework, to consider and, where applicable, offer to enter into agreements to facilitate connection requests from users of the transmission system.

3.164 The section below sets out how the cost assessment will be carried out, reviewing the costs associated with a connection request and associated project works.

3.165 Pursuant to paragraph 1 of the OFTO Standard Licence Conditions (**SLCs**) “before SLC E17 comes into effect, the licensee will have entered into an agreement with the Independent ISOP in accordance with the STC.

Under paragraph 2(e) of SLC E17:

“such costs as may be directly or indirectly incurred in carrying out the works, the extension or reinforcement of the licensee’s transmission system or the provision and installation, maintenance and repair or (as the case may be) removal following disconnection of any electric lines, electric plant or meters, which works are detailed in the offer"

3.166 Where the licensee has entered into an agreement with the ISOP in accordance with SLC E17, Amended Standard Condition E12-J4 requires the licensee to submit a notice, together with supporting evidence, setting out the costs that it will incur in complying with that agreement.

3.167 It also allows for us to determine the revenue adjustment required to "remunerate the efficient costs that the Authority considers to have been reasonably incurred by the licensee". Ofgem expect that a record of any required additional expenditure related to the connection would be kept from the moment that the ISOP contacts the OFTO with a connection request.

3.168 These records should be inclusive of all costs, for example:

- all contract construction costs including assets
- both internal and external staff time and costs
- any design or engineering work within the design process
- equipment hires or purchase
- evidence of any financing costs
- disruption cost due to de- and re- energisation during works

3.169 All costs should be limited to the previously published amounts within the OFTO's charging statement for the time frame of the required work.

3.170 We also expect the licensee to provide a complete and transparent account of any additional financing arrangements put in place to fund expenditure associated with the SLC E17 connection. This should include the actual cost of capital raised specifically for this connection and its associated works. For the avoidance of doubt, we do not consider Ofgem's published IDC rates for the relevant period to be applicable for this purpose, nor should they be used as a proxy for the licensee's financing costs, unless evidenced that this is applicable.

3.171 After receipt of the above records Ofgem shall commence a review and conclude on appropriate renumeration of reasonably incurred expense in reference to Amended Standard Condition E12-J4 as mentioned above.

3.172 The ownership, boundaries and licensing of any other equipment needed to complete these types of connections and similar co-location connections are currently under discussion between DESNZ, NESO and Ofgem. When there is a consensus on the treatment of these assets, we will update the guidance to reflect this.

Send us your feedback

We are keen to receive your feedback about this guidance. We would also like to get your answers to these questions:

- Do you have any comments about the quality of this guidance?
- Do you have any comments about its tone and content?
- Was it easy to read and understand? Or could it have been better written?
- Do you have any further comments?

Please send your feedback to stakeholders@ofgem.gov.uk.

Appendices

Index

Appendix 1	Cost Assessment and Tender Process
Appendix 2	Summary of CAT cost categories
Appendix 3	Submission Checklist
Appendix 4	Demonstrating Economic & Efficient Single-Source Procurement
Appendix 5	Detail of spares categories
Appendix 6	Glossary

Appendix 1 Cost Assessment and Tender Process

A1.1 Table A1 below summarises the stages involved in the cost assessment process and how these stages fit in with the stages of the Tender Process. This is provided for illustrative purposes only as the stages may differ for individual projects and tender rounds.

Tender Process	Cost Assessment Process
Qualifying Projects and Tender Entry Conditions A Developer provides Ofgem with information on their project. The project must satisfy certain conditions, stated in the Tender Regulations, in order to become a Qualifying Project and for Ofgem to commence the tender. The Qualifying Project must satisfy certain conditions notified by Ofgem (the **Tender Entry Conditions**). Ofgem determines whether the project meets the Tender Entry Conditions and notifies the relevant Developer. **Tender Commencement** Ofgem publishes a tender commencement notice including a list of projects that have qualified for the tender. Following this, as part of the initial stage of the OFTO tender process, Ofgem publish an Initial Transfer Value (InTV) for the project.	**First view on costs – Initial Transfer Value (InTV)** Ofgem requests a 'first view' from the developer of how much their offshore transmission assets will cost to build. Ofgem sends the developer a pro forma cost template which requires them to break down their costs into certain categories. Ofgem sets an Initial Transfer Value (**InTV**) based on the submissions by the developer. Ofgem completes high level checks on the data but does not analyse these costs in detail at this stage. The InTV for the project is published by Ofgem in the EPQ document.
Pre-Qualification Stages: Enhanced Pre-Qualification (EPQ) or Pre-Qualification (PQ) and Qualification to Tender (QTT) Ofgem publishes an EPQ Document specific to the Tender Round in question (i.e. relevant to all Qualifying Projects in the relevant Tender Round). This sets out the requirements Bidders (potential OFTOs) must meet to order to potentially be invited to participate in the next stage of the bidding process. After the evaluation of EPQ submissions has completed, Ofgem will decide and publish a shortlist of Qualifying Bidders to be invited to proceed to the next stage of the tender process.	**Indicative Transfer Value (ITV)** During the EPQ stage of the Tender Process, Ofgem and its advisers carry out a detailed cost assessment review, a forensic accounting review and, where relevant, a technical analysis of the costs submitted by the developer. The findings of this work are used to establish the Indicative Transfer Value (**ITV**) of the project. The ITV for the project is published by Ofgem at the commencement of the ITT stage.

Invitation to Tender (ITT) Stage Ofgem publishes a Qualifying Project specific ITT Document to the invited shortlist of Qualifying Bidders. This outlines the evaluation criteria Ofgem will consider when determining a Preferred Bidder (**PB**), as well as the Indicative Transfer Value (**ITV**). Qualifying Bidders will collate and submit their bids based on all the information published by Ofgem and provided by the Developer via a virtual dataroom. After evaluating the bids, Ofgem announces a PB who then move to the next stage. There may also be a Reserve Bidder (RB) appointed at this stage in case the PB does not become a Successful Bidder.	
Preferred Bidder (PB) Stage The PB and the Developer will agree the form of documents relating to the transfer of the transmission assets. Ofgem will draft a project specific OFTO Licence. This will include an up to 25 year[25] Tender Revenue Stream (**TRS**) bid by the PB and modified according to the Final Transfer Value (**FTV**). At this point a 28-day Section 8A Consultation[26] takes place. This provides an opportunity for other parties, particularly unsuccessful Qualifying Bidders, to see the final TRS value bid by the PB. **Successful Bidder (SB) and Licence Grant** This stage starts with a notice from Ofgem of its intention to grant the licence to the SB. After a 'standstill period', the final commercial documents are executed and the OFTO Licence is granted and published. This is followed by financial close and asset transfer.	**Final Transfer Value (FTV)** During the PB stage of the tender process, Ofgem finalises the cost assessment for the project based on updated information from the relevant developer. As with the ITV stage, Ofgem employs accounting advisers and, where relevant, technical advisers to carry out a review of all contract expenditure. Ofgem sends the developer and the PB a draft cost assessment report incorporating a Final Transfer Value for the transmission assets of the project. After allowing an appropriate time for review and comments (normally two weeks), Ofgem will publish the cost assessment report at the same time as the publication of the section 8A notice. The published report may include redactions to preserve commercial confidentiality.

[25] 25 years from TR6 onwards, 20 years for TR5.
[26] This refers to Section 8A of the Electricity Act 1989.

Appendix 2 Summary of CAT cost categories

CAT Template, cost reporting

[name] Offshore Windfarm Development	
CR1 - Costs overview	Summary of all individual cost categories and cost movements
CR2 - Offshore Substation	Includes topside, foundations, transformers, control equipment, switch gear
CR3 - Submarine Cable(s)	All cost associated with cable supply, cable installation, cable burial, mattressing, interlinks
CR4 - Onshore Cable(s)	All costs associated with supplying and installing the onshore cable
CR5 - Onshore Substation	Includes civil contract, transformers, control equipment, switch gear
CR6 - Reactive Substation	Reactives, harmonics, SVC, mid-point compensation platform
CR7 - Connection	Cost for grid connection
CR8 - Other	Development, project management, insurance etc
CR9 - Transaction	Transaction costs

CR1 - Cost overview

Costs Overview	**Cost Category**	**ITV Variance (ITV Projected - InTV Projected)**	**ITV Project Costs**	**ITV Outcome**	**ITV Reconciliation (Outcome – Projected)**
Offshore Substation(s)	CR2A + CR2B				
Submarine cable(s) supply & installation	CR3				
Onshore cable(s) supply & installation	CR4				
Onshore substation	CR5A + CR5B				
Reactive Substation	CR6				
Connection	CR7				
Other	CR8				
Transaction	CR9				
Total capital costs (includes contingency, claims, variations & future costs)					
IDC					
Total costs					

CR2 – CR9 categories and related cost

Cost category	Costs included
CR2A & B - Offshore Substation/Converter	*Design of piles/jacket/monopile*
	Supply of piles/jacket/monopile
	Installation of piles/jacket/monopile
	VOs piles/jacket/monopiles
	Design of topsides
	Supply of topsides
	Installation of topsides
	Design, Supply and Installation of electricals
	Category specific project management
	Other shared OSP costs (e.g. Vessels, Accommodation, CTV, Fisheries, Fuel, Surveys, Boulder clearance, UXO, SCADA equipment, J-Tubes)
	Spares
	Contingency
CR3 - Submarine Cable	***Export Cable(s)***
	Design and supply
	Installation
	Other shared costs (e.g. Vessels, Accommodation, CTV, Fisheries, Fuel, Surveys, Boulder clearance, UXO*)*
	Spares
	Contingency
	Interlink(s)
	Design and supply
	Installation
	Design, supply and installation of electricals
	Share of accommodation associated with interlink(s)
	Interlink J tubes
	Share of OSP structure associate with interlink(s)
	Spares
	Contingency
CR4 – Onshore cable	*Supply of cable*
	Installation of cable
	HDD
	Crossings
	Onshore site preparation
	Category specific project management
	Other shared land cable costs (e.g. Landowner agreements, Crop compensation*)*
	Spares

	Contingency
CR5A & B – Onshore Substation/Converter	*Design, Supply and Installation of electricals*
	Design Civils
	Onshore site preparation
	Construction
	Other shared ONS costs (e.g. Landowner agreements, SCADA, Crop compensation*)*
	Project management
	Spares
	Contingency

Cost category	**Costs included**
CR6 – Reactive Substation	***Reactive & Harmonic Equipment***
	*Design & Supply (*Onshore Reactive, Onshore harmonics)
	*Design & Supply (*Offshore Reactive, Offshore harmonics)
	Project management
	Spares
	Contingency
	Mid-point compensation platform
	Design of piles/jacket/monopile
	Supply of piles/jacket/monopile
	Installation of piles/jacket/monopile
	VOs piles/jacket/monopiles
	Design of topsides
	Supply of topsides
	Installation of topsides
	Category specific project management
	Other shared OSP costs (e.g. Vessels, Accommodation, CTV, Fisheries, Fuel, Surveys, Boulder clearance, UXO, SCADA equipment*)*
	Spares
	Contingency
CR7 – Connection	*Cable - supply and install*
	Grid connection agreement
	Connection works (developer or onshore TO)
	Project management
	Contingency
CR8 – Other	*End to end shared costs (e.g.* Insurance, Legal fees, HSEE*)*
	Development (e.g. Acquisition Costs, Design & resources, Consents & environmental planning)
	End to end project management
CR9 – Transaction	*Overall project contingency*
	Transaction costs

Appendix 3 Submission Checklist

Cost Assessment List of Prepared Documentation for InTV.

These should be within the project Data room as supplied by OFGEM.

- Cost Assessment Template (CAT)
- Evidence of the Transmission specific Internal Rate of Return (I.R.R.)

Cost Assessment List of Prepared Documentation for ITV and FTV.

These should be within the project Data room as supplied by OFGEM.

- CAT
- Upload of all main contracts for supply and installation that have been mentioned within the CAT
- Upload of all contract Variation Orders (VO) that are mentioned within the CAT or that are in negotiation
- List of locations for contracts and VOs within an excel sheet including a separate tab with an estimated timeframe for anything that is currently unavailable but that will become available during the cost assessment process and of anything that will not be available
- A list of proposed spares for transfer from Developer to OFTO Bidder specifically spare cables for onshore and offshore usage and any spare large equipment that will form an immediate replacement of connected equipment and will be transferred
- Project Plan for the OFTO construction process showing as planned and as built
- Memos on any large project specific factors that have hindered project progress or caused significant specific expenditure
- Any explanatory information available on project development prior to Final Investment Decision (FID), covering any major DEVEX decisions or purchase of the project from other parties
- Any explanatory information available on any Anticipatory Investment (AI) or shared costs between multiple projects that have been included within the submitted CAT
- Any explanatory information available on land purchase, leasing or farm payments for project usage
- Any explanatory information available on fishery payments or underwater explosive disposal for the project
- Any explanatory information available on legal costs currently incurred, including how they are distributed across the project cost categories

- Any explanatory information available on insurance costs and a breakdown of types of cover purchased
- Any explanatory information available on developer requirement or OFTO requirement for offshore and onshore construction, including generator weight and space calculations

For the ITV forensic review, the following information should be provided:

- Details of the ownership structure of the Wind Farm
- Details of how the cost template has been prepared and of the systems used by the Wind Farm to record incurred costs and determine future costs
- Confirmation of the official date of the cost template submitted to Ofgem
- Confirmation of expected date of:
    - Construction completion
    - First power
    - Commercial operations
- Supporting documentation for every cost included in the cost template over £250,000:
    - For amounts in the cost template where the Wind Farm has entered into contract, name of contractor and a copy of the contract (including any schedules of amounts or payments) (please include exact data room location in the CAT). Evidence of any variations to these amounts, (e.g. signed variation orders or copies of supplier communications)

      NB: Where the amount of the contract is not equal to the amount in the cost template, please provide a reconciliation between the two and providing supporting documentation for any reconciling items
    - For amounts in the cost template that represent estimated amounts, where such amounts are over £250,000, schedules/detailed calculations to support the estimates made (e.g. budgets, estimates from suppliers or historical information the estimate is based upon – please include exact data room location in the CAT)

      NB: Where internal schedules are provided, please ensure that they are provided to us in Excel wherever possible (including all formulas and links to further workings where applicable) so that it is clear how calculations have been derived.
    - For amounts in the cost template that are neither a) or b) above, supporting documentation should include an explanation of the nature of the cost and detailed supporting workings and breakdowns evidencing how the cost amount has been derived

    - Details of reconciliations to trace the ITV CAT to supporting workings, where relevant

- A detailed description of the tender process operated by the Wind Farm, together with supporting documentation evidencing this process in relation to all significant contracts (offshore substation, cabling supply and installation, onshore substation) be provided including:
    - Tender evaluation documentation
    - List of parties participating in the tender
    - Commercial tender documentation submitted by successful suppliers. For the avoidance of doubt, we do not require sight of drawings, designs, technical specifications etc, but will require the invitation to tender and the tender evaluation document

- Details of the Wind Farm's processes:
    - A detailed explanation of the governance procedures in place across the cost control function, including hierarchy and decision-making processes
    - A detailed explanation of the invoice and purchase order (PO) process, from raising a PO to payment of invoices, including hierarchy and decision-making process descriptions/approvals
    - A detailed explanation of the accounting and budgeting processes that feed into the CAT

- Cost allocations in the CAT:
    - Detailed explanations and supporting workings showing the calculation of all transmission assets (OFTO) allocation percentages applied throughout the CAT to the shared cost
    - A detailed explanation of how costs allocated to the transmission assets are split between the CR categories within the CAT, where relevant

- Contingencies:
    - Detailed workings to support all contingency figures included in the CAT, including details of the risks associated within the contingency figures
    - A detailed description of the process for estimating these figures (for instance who is consulted in the preparation of these figures and detail of risk assessment if appropriate, what assumptions have been used and why?) and a breakdown of the contingency provision

- Foreign exchange:

  - Detail on how foreign exchange transactions are recognised by the Wind Farm project, the foreign exchange rates used in the ITV CAT and how adjustments are calculated, where applicable
  - Supporting detailed workings showing how the foreign exchange rates used for the purpose of the CAT have been calculated
  - Detail of any current exposure to foreign exchange variances and any forward contracts that have been entered into for the purchase of foreign currency

- Detailed explanations and supporting workings of all development costs in the CAT

- Detailed workings to support all resourcing/staff costs included in the CAT, including:

  - a description of the process for calculating all resourcing/staff costs (including how rates and hours have been derived)
  - a description of the assumptions used for any forecast amounts
  - how these costs are allocated across the ITV CAT
  - Supporting evidence for any rates and hours applied in the calculations, where applicable

- Details of any related party transactions between the Developer and the Wind Farm (including but not limited to resourcing/staff costs and project management costs), and the basis of calculation for each

- Where contracts for the transmission assets have been entered into with companies for whom the Wind Farm developer has global supply arrangements, details of how any discounts or rebates earned on such global supply arrangements have been reflected in the cost of the transmission assets

- Detailed explanations and supporting workings of any recharges between this Wind Farm and other Wind Farm Projects under the same/similar ownership, where applicable

For the FTV forensic review the following information should be provided:

For Direct costs

- Schedule of invoices paid under contracts selected by Ofgem, separated between invoices for contracted amounts (milestones) and invoices for variations

  - Copies of all invoices
  - Copies of purchase and nominal ledger accounts showing the posting of the invoices, and of the subsequent payment

- ○ Copies of bank statements showing the payment of the invoices

- Reconciliation of invoice schedules to the amount of the underlying contract, including details and supporting documentation for reconciling amounts
- Reconciliation of invoice schedules to the cost template, separating reconciling items between amounts accrued and amounts estimated, and documentation to support the reconciling amounts including calculations of any estimates
- Details of how foreign exchange has been managed on the contracts, including the allocation of any losses to the contracts and the exchange rates used

For Indirect costs

- Schedule of indirect costs selected by Ofgem, including details of how costs are allocated to the transmission assets and calculation of the allocation rate. These costs should be reconciled to the cost template

For direct costs and indirect costs

- Variance analysis of movements between the cost template used for the ITT and the latest assessment, providing an explanation and supporting documentation for significant reconciling items (typically variations between lines on the CAT of more than £250,000)

Appendix 4 Demonstrating Economic & Efficient Single-Source Procurement

Developers should evidence that single-source procurement is driven by genuine constraints, that alternatives have been properly considered, and that robust mechanisms are in place to maintain cost discipline and protect consumers. The below evidence may be requested to support our assessment of whether project costs are economic and efficient.

A4.1 Justification for Single Sourcing

- Clear explanation of technical or interoperability constraints requiring a specific supplier
- Evidence that no viable alternative suppliers or solutions exist
- Description of project configuration dependencies (e.g. alignment with third-party assets)

A4.2 Assessment of Alternatives

- Summary of technical options considered, including reasons for rejection
- Evidence of market engagement (e.g. RFIs, supplier discussions, expressions of interest)
- Any cost-benefit analysis or engineering studies undertaken to assess alternatives

A4.3 Evidence of Market Constraints

- Description of prevailing market conditions (e.g. limited suppliers, capacity constraints)
- Evidence that a competitive tender would be impractical, high risk, or unsuccessful
- Examples of supplier behaviour, such as unwillingness to bid under traditional processes

A4.4 Measures to Maintain Competitive Discipline

- Use of benchmarking against:
    - Framework reference pricing
    - Comparable projects or historic data
- Evidence of cost challenge and negotiation processes with the supplier
- Any independent cost assurance or “should-cost” modelling

A4.5 Use of Competitive Frameworks or Contracting Mechanisms

- Evidence that procurement is undertaken via a previously competitively tendered framework, where applicable

- Explanation of how the framework provides:
    - Reference pricing and cost transparency
    - Standard terms and conditions supporting value for money

A4.6 Cost Risk Management and Consumer Protection

- Evidence of risk allocation and mitigation (e.g. for delays, cost escalation)
- Demonstration that unnecessary costs have been minimised
- Measures to ensure consumers are protected from supply chain risks and late delivery

A4.7 Governance and Auditability

- Clear decision-making records supporting the procurement approach
- Evidence of internal approvals and challenge processes
- Full audit trail of procurement decisions and cost build-up

A4.8 Alignment with Regulatory Assessment

- Explanation of how the approach supports an economic and efficient outcome overall

Appendix 5 Detail of spares categories

Spare Class	Category	Definition	Characteristics	Assessment and Evidence Required
1	System Critical Strategic Spares	Spare items required to meet the availability target: Spare items that are fundamental to achieving the minimum availability target. Without these spares, the system would be expected to breach the availability requirement when exposed to credible failure scenarios.	Direct and material impact on **Availability Target** Typically associated with: • Single-point failure exposure • Lack of inherent redundancy in system design Required to support credible repair scenarios Often linked to long recovery durations if unavailable Example(s) – [non-exhaustive]: • Export Cable Spare Length • Offshore Cable Joint	Reliability, Availability, and Maintainability (RAM) report/ assessment clearly justifies it and shows clear alignment with critical/ contracted RAM classification Developer can demonstrate this is intrinsically strategic through RAM or other substantiated evidence Forms the minimum justifiable spare holding Developer/ RAM report can demonstrate above through: • Failure scenario Repair strategy (marine logistics, access windows) • Lead time vs outage duration • Sensitivity: Availability with/without spare

2	High-Impact Long Lead Spares (bespoke main plant item products)	Spare items that are not strictly required to meet the availability target, but which significantly reduce the duration and impact of outages where replacement lead times or access constraints are material.	Limited impact on whether the availability target is affected but Significant impact on how efficiently it is maintained Driven by: • Long manufacturing lead times • Logistical constraints (e.g. offshore access, transport limitations) • Typically associated with prolonged outage risk rather than high failure frequency Spares that act as risk mitigators, protecting against low-probability, high-impact events. Example: • HVDC control/protection Modules • Valve auxiliary systems (cooling skids, control racks) • Specialised offshore auxiliary systems	Considered conditionally strategic Requires clear justification of: Lead time vs repair time Disproportionate outage exposure if spare item is unavailable / has to be procured reactively Developer/ RAM report can demonstrate above through: • Lead time (months vs days) • Offshore access constraints Lack of redundancy • OEM supply risk
3	OEM Modular / Replaceable Strategic Sets	Spare sets forming part of planned replacement cycles or	Primarily impacts maintainability rather than availability. Limited impact on whether availability target is met but	Considered conditionally strategic.

		modular repair strategy. Spare holdings that support a defined modular replacement or repair approach, enabling restoration of service through component substitution rather than in situ repair, forming part of a structured maintenance philosophy.	reduces recovery time and improves system restoration efficiency. Driven by: • Need for rapid restoration of service • Infeasibility of on-site repair • Defined modular maintenance philosophy. Typically associated with medium frequency failure components. Example items: • Modular electronic units • Replaceable sub-assemblies • Cooling system replaceable units	Requires clear distinction between: • Initial strategic holding (potentially allowable) • Ongoing replenishment (operational cost) Developer / RAM report can demonstrate above through: • Defined maintenance / replacement strategy • Impact on MTTR / MDT • Minimum stock level justification • Replacement cycle evidence • Sensitivity: recovery time and availability with / without modular spares • Impact on efficiency of operation
4	Major Plant Strategic Spares (Exceptional)	Large, high-value equipment spares where operational benefit is clear but economic justification is difficult.	Very low failure probability and very high consequence of failure. Typically associated with long replacement timelines and high procurement costs. Often mitigated by system redundancy	Considered exceptional and subject to high scrutiny. Not justified on availability improvement alone. Requires strong justification of: • Severity of consequence

		Spare items associated with low probability but high consequence failure events, where the impact of failure is severe, but occurrence is infrequent.	or alternative operational configurations. Limited impact on the availability target in most standard scenarios. Driven by: • Extreme consequence of failure • Long manufacturing / replacement duration • Limited supply chain availability. Example items: • Major plant equipment units • Large bespoke system components • Long-lead high-value assemblies	• Lack of redundancy or workaround • Comparison with alternative mitigations. Developer / RAM report can demonstrate above through: • Worst-case failure analysis • Outage duration without spare • Supply chain constraints • Cost vs avoided outage exposure • Demonstration that alternative mitigation strategies are insufficient
5	Resilience / Enhancement Spares	Spare items that improve availability beyond target but are not required to meet it. Spare items that enhance system resilience, flexibility, or performance beyond the minimum	No impact on whether availability target is met. Improves recovery speed and operational flexibility. Represents additional redundancy beyond baseline requirements. Marginal impact on availability/ efficiency of operation but may be	Considered non-essential. Requires demonstration of economic efficiency and proportionality. Developer / RAM report can demonstrate above through: • Sensitivity analysis showing incremental availability improvement

		availability requirement.	required/beneficial to provide additional redundancy. Driven by: • Desire to enhance system resilience • Reduction of operational risk beyond minimum requirement • Performance optimisation. Example items: • Additional spare units beyond baseline • Secondary spare holdings • Additional modular stock	• Justification of resilience benefit • Cost-benefit comparison • Evidence that holding is proportionate to risk reduction and not excessive
6	Operational / Maintenance Stock (Non-Strategic)	Routine inventory used for ongoing maintenance and operations, not tied to asset transfer. Inventory required to support routine inspection, maintenance, and operational activities, without material	No material impact on availability or maintainability. Supports routine maintenance and preventative replacement activities. Typically, high frequency, low consequence usage items. Readily available through standard supply chains. Driven by: • Routine maintenance requirements	Considered non-strategic and typically classified as operational expenditure (OPEX). Not justified as part of strategic spare holding unless clearly linked to asset transfer. Developer should demonstrate: • Clear separation from strategic spares • Not routine maintenance stock

		impact on system availability.	• Preventative maintenance schedules • Operational support needs. Example items: • Consumables • Standard replaceable components • Routine instrumentation parts	• No duplication within operational cost allowances • Evidence that inclusion is not related to standard maintenance practices

Appendix 6 Glossary

A

Anticipatory investment (AI)

Investment that goes beyond the needs of immediate generation, reflecting the needs created by a likely future generation project or projects.

Authority

The Gas and Electricity Markets Authority established by section 1(1) of the Utilities Act 2000. The Authority governs Ofgem.

B

Best and Final Offer (BAFO) Stage

A stage of a Tender Exercise which the Authority may decide to run after the ITT Stage in order to determine which Qualifying Bidder shall become the Preferred Bidder in respect of a Qualifying Project. The stage will commence with Ofgem distributing the BAFO document to selected Qualifying Bidders and includes the preparation, submission and evaluation of BAFO submissions and ends when a Preferred Bidder is selected and notified.

Bidder

Any person or Bidder Group that makes a PQ, EPQ, QTT, ITT or BAFO submission in accordance with the Tender Regulations.

Bidder Group

Two or more persons acting together as a consortium for the purposes of any PQ, EPQ, QTT, ITT or BAFO submission to Ofgem in accordance with the Tender Regulations.

C

Capex

Capital Expenditure – defined as the costs involved in the delivery, construction and installation (including civil works) of offshore transmission assets.

Cost Assessment Template (CAT)

The pro-forma cost assessment template provided by Ofgem to the developer which the developer should use to submit its costs information. The information required to be included in the CAT is set out in Appendix 2 to this document.

D

Developer

The Tender Regulations define a ‘developer’ as ‘any person within section 6D(2)(a) of the Electricity Act 1989’. Section 6D(2)(a) of the Electricity Act defines such person as ‘the person who made the connection request for the purposes of which the tender exercise has been, is being or is to be, held'. In practice, such person is also the entity responsible for the construction of the Generation Assets and, under Generator Build, the transmission assets. Under Generator Build, this is the person who requests that Ofgem commence the Tender Process in respect of a proposed project.

Direct PM costs

Has the meaning given in paragraph 3.28 of this document.

E

Electricity Act

The Electricity Act 1989 as amended from time to time.

End-to-end PM costs

Has the meaning set out in paragraph 3.28 of this document.

Enhanced PQ (EPQ) Stage

An extended version of the PQ stage of the Tender Exercise that can be used for Generator Build projects where the Authority decides not to run a QTT Stage. At the end of the EPQ Stage, the Authority will determine which Bidders become Qualifying Bidders and will be invited to participate in the ITT Stage of the Tender Exercise for each Qualifying Project.

F

FID

Final investment decision is a final decision of the Capital Investment Decision (CID) as part of the long-term corporate finance decisions based on key criteria to manage company's assets and capital structure. It is the point at which contracts for all major equipment can be placed, allowing procurement and construction to proceed and engineering to be completed.

Final Transfer Value (FTV)

The final transfer value set by Ofgem in accordance with paragraphs 2.19 to 2.39 of this guidance document.

G

Generation Assets

The assets forming the generation elements of the project which are to be retained by the developer.

Generator Build

A model for the construction of transmission assets. Under this model, the developer carries out the preliminary works, procurement and construction of the transmission assets.

I

IDC

Interest during construction. As set out in paragraph 3.88of this document.

Indicative Transfer Value (ITV)

The indicative transfer value set by the cost assessment team, as set out in paragraphs 2.15 to 2.18 of this document.

Initial Transfer Value (InTV)

The initial value set by the cost assessment team as set out in paragraph 2.10 of this document.

Invitation to Tender (ITT) Stage

The stage of a Tender Exercise during which the Authority may determine which Qualifying Bidder becomes the Preferred Bidder or whether to hold a BAFO Stage. This stage commences with the distribution of the ITT Document to Qualifying Bidders by Ofgem and includes the preparation, submission and evaluation of ITT submissions.

Independent System Operator and Planner (ISOP)

The Independent System Operator and Planner (ISOP) is an expert, impartial body with responsibilities across both the electricity and gas systems, driving progress towards net zero while maintaining energy security and minimising costs for consumers. It performs a number of important functions from the real time operation of the electricity system, through to energy market development, managing electricity system connections and leading on strategic energy network planning.

ITT Document

The document prepared and issued by Ofgem to each Qualifying Bidder invited to make a submission at the ITT Stage, and which sets out the rules and requirements of the ITT Stage.

L

Licence Grant

Following its determination to grant an OFTO Licence to the Successful Bidder, the Authority confirms such determination in accordance with regulation 29(5) of the Tender Regulations and grants such OFTO Licence to the Successful Bidder pursuant to section 6(1)(b) of the Electricity Act.

O

Ofgem

Office of Gas and Electricity Markets. Ofgem, “the Authority” and “we” are used interchangeably in this document.

OFTO

Offshore transmission owner.

Offshore Transmission Owner (OFTO) Licence

The licence awarded under section 6(1)(b) of the Electricity Act following a Tender Exercise authorising an OFTO to participate in the transmission of electricity in respect of the relevant transmission assets. The licence sets out an OFTO's rights and obligations as the offshore Transmission Asset owner and operator.

OSP

Offshore substation platform.

P

Post-Tender Revenue Adjustment (PTRA)

An adjustment to the Base Transmission Revenue (as defined in the OFTO Licence) under Amended Standard Condition E12-A3 of the OFTO Licence to account for any difference between the Indicative Transfer Value and the Final Transfer Value.

Preferred Bidder (PB)

In relation to a Qualifying Project, the Bidder determined by Ofgem following its evaluation of the submissions received, to which Ofgem intends to grant the OFTO Licence subject to the satisfaction of the conditions specified by Ofgem in accordance with the Tender Regulations.

Q

QTT Stage

Qualification to tender stage.

Qualifying Bidder

Any person or Bidder Group that is invited to make an ITT Submission, a Preferred Bidder, a Reserve Bidder or a Successful Bidder (as applicable).

Qualifying Project

An offshore transmission project in respect of which Ofgem determines that the developer has satisfied the requirements set out in paragraph 2 of Schedule 1 to the Tender Regulations or will use its reasonable endeavours to satisfy the relevant Qualifying Project requirements within a period specified by Ofgem.

S

Section 8A Consultation

The public consultation required by section 8A of the Electricity Act for any modifications to the standard conditions of the OFTO Licence to be made at Licence Grant. The modifications are required in order to incorporate the project specific provisions in the relevant licence. The consultation must run for at least 28 days.

Supplementary Question (SQ)

A request for information issued by Ofgem, its advisers, or a developer to capture additional clarifications on project-specific issues and the cost assessment process. SQs are used to seek supporting evidence, explanations or clarification and typically form part of the ongoing exchange of information during a cost assessment.

Successful Bidder (SB)

The Preferred Bidder in a Tender Exercise who has resolved the PB Matters (as defined in the TPGD) to the Authority's satisfaction, such that the Authority intends to grant to it an OFTO Licence.

T

Tender Exercise

Each tender exercise run in accordance with the Tender Process.

Tender Process

The competitive tender process run by Ofgem in accordance with the Tender Regulations in order to identify a Successful Bidder to whom a particular OFTO Licence is to be granted.

Tender Process Guidance Document (TPGD)

The guidance document setting out the Tender Process. A link to the most recently published guidance (as at the date of publication of this guidance document) is contained in section 1, p.5.

Tender Regulations

Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015.

Tender Revenue Stream (TRS)

The payment an OFTO receives over its revenue term.

Transmission owner (TO)

An owner of a high-voltage transmission network or asset.

Transmission assets

The transmission assets which are transferred to the OFTO and are expected to include subsea export cables, onshore export cables, onshore and offshore substation, and any other assets, consents, property arrangements or permits required by an incoming OFTO in order for it to fulfil its obligations as a transmission operator.

Transmission Network Use of System (TNUoS) charges

Charging arrangements that reflect the cost of installing, operating and maintaining the transmission system.