Final impact assessment

Final impact assessment on Pathway to 2030 workstream's decision on the Delivery Model option			
Division:	Networks	**Type of measure:**	Competition in Offshore Transmission Networks
Team:	Offshore Coordination	**Type of IA:**	Qualified under Section 5A UA 2000
Associated documents:	Revised Minded-to Decision and further consultation on Pathway to 2030 Minded-to Decision and further consultation on Pathway to 2030	**Contact for enquiries:**	Viljami Yli-Hemminki Cher-Rae Fairlie 020 3263 2755 / 020 7901 3902 Offshore.coordination@ofgem.gov.uk
Coverage:	Full	**Date:**	31 March 2023

Summary

This document is a final impact assessment that sets out an assessment of our decision for the delivery models developed through the Offshore Transmission Network Review (**OTNR**) Pathway to 2030 (**PT2030**) workstream. We have developed this final impact assessment in accordance with our impact assessment guidance.[1][2] The purpose of this final impact assessment is to bring together the analysis and results of our coordinated non-radial delivery model policy development process, to confirm the preferred options. To provide a comprehensive and integrated overview, we discuss the various alternative options which were discounted by the previous publications and their impact assessments.

What is the problem under consideration? Why is Ofgem intervention necessary?

The current frameworks for developing and connecting offshore wind generation are being reviewed in light of the government's increased ambition for offshore wind. In 2019, the government stated[3] its target of achieving a significant increase in offshore wind capacity, from the current level of around 10GW to 40GW by 2030. In April 2022, the then Prime Minister announced a new British Energy Security Strategy (**BESS**), which built on previous offshore wind targets, to increase offshore wind ambition to 50GW by 2030.[4] Radial offshore transmission links[5] for this amount of offshore wind generation are unlikely to be economical, appropriate, or acceptable for consumers, local communities or the environment.

The objective of the OTNR is to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, whilst considering the increased ambition for offshore wind to achieve net zero. The OTNR aims to ensure that future connections for offshore wind are delivered with increased coordination whilst ensuring an appropriate balance between environmental, social and economic costs. The OTNR has now transitioned from reviewing to reforming, as we begin to implement the regulatory and planning changes necessary to deliver a coordinated offshore transmission network.

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[1] Impact Assessment Guidance | Ofgem
[2] The Green Book and accompanying guidance and documents - GOV.UK (www.gov.uk)
[3] Queen's speech December 2019 background briefing notes (publishing.service.gov.uk)
[4] British Energy Security Strategy (publishing.service.gov.uk)
[5] To date, offshore windfarms in GB have been connected to the shore via standalone radial (point-to-point) transmission links. With more offshore windfarm projects planned, many of which are further from shore than those developed to date, there is potential for efficiencies from greater coordination of offshore transmission infrastructure.

Policy making process leading up to the final decision

In July 2021, we published our 'Consultation on changes intended to bring about greater coordination in the development of offshore energy networks', hereafter referred to as the July 2021 publication.[6] In the publication we considered six potential delivery models for the delivery of coordinated non-radial offshore transmission assets in scope of this workstream. Non-radial offshore transmission assets were later indicated by the National Grid Electricity System Operator (**NGESO**) produced Holistic Network Design (**HND**)[7] and classified by our asset classification process.[8] Further non-radial offshore transmission assets may be indicated by the ongoing HND Follow-Up Exercise (**HNDFUE**).

In January 2022, we published our 'Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks'[9], hereafter referred to as the **January 2022 update**. It summarised the consultation responses and, based on the feedback and some initial analysis, excluded the early competition delivery models. The January 2022 update also introduced a late competition Offshore Transmission Owner (**OFTO**) build model, where the generator designs and consents the assets with the construction phase being undertaken by an OFTO.

In May 2022 we consulted on our minded-to decision to adopt a very late competition generator build model for PT2030 (our **May 2022 publication**). Under the very late competition generator build model, generators deliver and construct the assets before they are tendered, therefore, competition only focuses on the financing, operation and maintenance of the assets. We also confirmed that where the HND indicates a radial connection, developers would use the delivery models currently available through the existing OFTO regime (ie very late competition generator build or late competition OFTO build models).

Stakeholder feedback to the May 2022 publication, the publication of the HND and the accompanying asset classification process, led us to reconsider the assumptions underpinning our May 2022 minded-to decision and to review our policy position. In December 2022 we published our revised minded-to decision which outlined an expanded package of options from which developers can choose when delivering coordinated assets (our **December 2022**

[6] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[7] A Holistic Network Design for Offshore Wind | National Grid ESO
[8] Offshore Transmission Network Review: Decision on asset classification | Ofgem
[9] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

publication). We proposed to give developers the choice of either a very late competition generator build model or a late competition OFTO build model for delivery of non-radial offshore transmission assets. We further outlined our minded-to decision to extend the option for Anticipatory Investment (**AI**) for assets within the scope of the PT2030 workstream, in a similar way that this policy applies to projects within the Early Opportunities workstream.

Responses to our December 2022 publication overwhelmingly agreed with our revised minded-to decision which now forms our final decision. Please see the accompanying decision for a further breakdown of the consultation responses.

May 2022 minded-to decision and first draft impact assessment

The May 2022 publication[10] considered various delivery model options, comprising of different participants in the delivery process having greater or lesser roles in designing, consenting, building and owning the non-radial offshore transmission assets. The May 2022 publication was accompanied by a draft impact assessment. The options also included different competition models: late, very late and no competition. We had previously discounted the early competition models in our January 2022 update.[11] We discounted these options due to policy development and tender-related time constraints. The respondents to our July 2021 consultation largely did not see early competition models as favourable or deliverable for the PT2030 projects. Some respondents to the July 2021 consultation did see the early competition models as possible viable options for the Future Framework workstream (formerly Enduring Regime) projects.

In the May 2022 publication, we explained our intention to adopt a very late (post-construction) competition generator build model for non-radial offshore transmission in scope of PT2030. Under this model, generators deliver and construct the assets before they are tendered. The competition only focuses on financing, operation and maintenance. We considered this model to be the best option to deliver the coordinated offshore transmission assets required to achieve the government's offshore wind generation targets, at a reasonable cost to consumers and in the timeframe available. This model has been used to date through the existing OFTO regime for radial projects, although we expect to make small changes to the cost assessment and tendering processes, as well as introducing the early-stage assessment process.

[10] Minded-to Decision and further consultation on Pathway to 2030 | Ofgem
[11] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

Our quantitative analysis supported the May 2022 publication's minded-to decision. We estimated that one year of delay, load factor depending, would cost between £1,116m and £1,464m. Three years of delay would cost between £3,209m and £3,975m. We contrasted these delay costs with potential cost savings brought on by varying competition models.

Revising the May 2022 minded-to decision in December 2022

Based on consultation responses and feedback, we revisited the May 2022 publication for the PT2030 non-radial delivery model in our December 2022 publication. We revised some of our earlier figures as, following our May 2022 publication, the HND[12] had been published and the asset classification process had been finalised. As a result, the December 2022 publication included the option for developers to choose a late competition OFTO build model, for non-radial offshore transmission assets, along with our original option for very late competition generator build model. Further, it included the extension of the AI policy from the Early Opportunities workstream.

The HND, together with the asset classification process, resulted in significantly fewer non-radial offshore assets than we had assumed in our first draft impact assessment.[13] By applying our classification process to the HND, it has resulted in six onshore, twelve radial offshore and three non-radial offshore transmission assets. Non-radial offshore transmission assets (5,400MW) comprised 15% of the total HND transmission assets (35,890MW). The lower number of non-radial offshore transmission assets led us to revisit the figures and assumptions that underpinned our May 2022 publication. HNDFUE[14] is underway and it will include the remaining ScotWind leaseholders, any capacity available through the ScotWind clearing process and 4.2GW of Celtic Sea capacity.[15] The asset classification process will also apply to the HNDFUE once the HNDFUE is finalised, expected later this year.

Our final decision

The revised minded-to decision of December 2022[16], which now becomes our final decision, gives developers of assets in scope of the HND and HNDFUE the option of:

[12] Pathway to 2030 Holistic Network Design summary report
[13] Offshore Transmission Network Review: Decision on asset classification | Ofgem
[14] OTNR Pathway to 2030 Central Design Group and Network Design Terms of Reference for development of the follow-up Holistic Network Design and follow-up Detailed Network Designs
[15] Further information about ScotWind inclusion in the HND and NGESO thinking can be found on the related NGESO press release on 11 February 2022.
[16] Our December 2022 publication was accompanied by an additional draft impact assessment which analysed the costs associated with not expanding the options available to developers.

- working collaboratively with other developers using a very late competition generator build model; **or**
- using AI in the very late competition generator build model; **or**
- opting to use a late competition OFTO build model for the delivery of non-radial offshore transmission assets.

What are the policy objectives and intended effects, including on Ofgem's Strategic Outcomes?

Ofgem is a key delivery partner of the OTNR. The objective of the PT2030 workstream is to drive the coordination of offshore projects progressing through Crown Estate (**TCE**) Leasing Round 4 (**LR4**) and Crown Estate Scotland (**CES**) ScotWind connecting to the transmission system by 2030. The workstream also captures a small number of projects from an earlier leasing round and the Celtic Sea leasing round which are included in the HND and HNDFUE.

What are the policy options that have been considered, including any alternatives to regulation?

This final impact assessment considers our decision of giving developers the choice between electing to use the very late competition generator build and late competition OFTO build models for the delivery of non-radial offshore transmission assets. We also consider the application of AI policy to projects in scope of the PT2030 workstream. In the Excluded Options section, we discuss the various alternative options which were discounted in our January 2022 update, May 2022 and December 2022 publications.

Preferred option - Monetised Impacts (£m)

Business Impact Target Qualifying Provision	Non-qualifying (competition)
Business Impact Target (EANDCB)	Not relevant
Net Benefit to GB Consumer	See below
Wider Benefits/Costs for Society	Significant benefits

Explain how the Net Benefit was monetised, NPV or other (*NPV calculated using 2022 as base year. Economic costs and benefits are in 2022 financial year prices covering the period from 2031 to 2032.*)

In this final impact assessment, we excluded delivery models due to their potential delay costs, their impacts on competition and the PT2030 targets.

In the first draft impact assessment, we estimated that the proposed very late competition generator build model scenario would not lead to delays. Conversely, in response to the May 2022 publication, respondents indicated that developers could struggle to coordinate without the extension of the AI policy and the right delivery model options. Without the AI policy extension, respondents noted that developers could be drawn into lengthy formal cooperation negotiations causing the projects to be delayed beyond the 2030 target. Additional complexity could arise if two projects are on different timescales and the AI policy is not extended to facilitate co-development.

Some respondents also expressed their desire to have a generator design, late competition OFTO build model as an option for non-radial offshore transmission assets. The late competition OFTO build model was seen as providing an additional route to delivery. OFTO build could be used, for example, in cases where developers cannot reach independent commercial agreements with each other or where AI cannot be used. Failing to provide several delivery options could increase the risk of non-delivery of coordinated assets.

We consider that our revised position helps avoid a one-to-two-year delay in delivery. The revised position, with the expanded options available to developers, helps developers avoid these delays when delivering coordinated assets. The expanded options help developers avoid lengthy negotiations involved with formal cooperation agreements.

We recognise that a risk of delay under one of the options (a late competition OFTO build) still exists. However, we consider this option to effectively mitigate against the risk of non-delivery by providing more optionality and flexibility to suit project-specific circumstances.

The number of non-radial offshore transmission assets is smaller than was originally assumed in the May 2022 publication. This change has reduced the aggregate cost associated with any delays. After the publication of the HND and the application of the

asset classification process, the non-radial offshore transmission assets account for 5.4GW of capacity. The first year of delay in terms of discounted carbon cost is now estimated at £147m-237m and two years is estimated at £267-429m. The first year of delay in terms of discounted option fees costs is estimated at £351m and cumulative two years at £679m. In total, if the options are not expanded and developers face a one-to-two-year delay, we estimate a delay cost to range from £499-588m and £946-1,108m, respectively. These delay costs are still substantial and avoiding them with the help of the delivery options package remains our priority.

We do not have concrete estimates on the number of non-radial offshore transmission assets when considering the inclusion of the HNDFUE into these calculations. The expanded AI policy, coupled with the two delivery model options, can help avoid extended negotiations between coordinating generators. Based on varying assumptions and scenarios, avoiding a one-to-two-years of delay caused by these negotiations can help avoid up to £825m-£1,537m in terms of additional carbon and option fee costs.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetise impacts, including mid-term strategic and long-term sustainability factors following Ofgem impact assessment guidance.

Our final decision's options allow developers to choose the most appropriate option for the delivery of the coordinated assets. The AI policy extension can reduce the complexity of negotiations between developers and provide additional options for delivery, which in turn can help reduce delays.

Competitive tendering has benefits in a range of areas. Increasing innovation and introducing new products, services and technologies are possible benefits of competitive tendering but these benefits are dynamic and hard to measure.

The utilisation of a late competition OFTO build can put downward pressure on transmission pricing. This model allows for alternative and extended financing routes for the construction and ownership phases of development. OFTOs would also be enabled to take a whole life approach to transmission investment which could deliver an overall lower cost of capital.

The very late competition generator build model has the benefit of insulating the OFTO from construction risks which can help to attract a low cost of capital for the operational phase, as observed from current OFTO projects.

Avoiding delays in delivery is important to help achieve offshore wind targets as soon as possible. Delivering offshore wind targets on time could increase GB energy security by reducing our exposure to volatile fossil fuel markets. It can reduce our wholesale market prices due to a higher proportion of low marginal cost generation. It can aid decarbonisation by increasing the volume of low-carbon generation on the system. Avoiding delays can also help achieve legally binding decarbonisation targets in a more timely fashion.

Section 4 sets out the assumptions used in our assessments for this impact assessment.

Will the policy be reviewed?	The scope of this policy is limited to a specific set of projects and so there would be limited value in reviewing for PT2030. As the OTNR's Future Framework is being developed, we will look to apply any lessons learned from the development and implementation of the PT2030 workstream.

Is this proposal in scope of the Public Sector Equality Duty?	Yes, we expect consumers to benefit in general, regardless of any protected characteristics.

Contents

1. Introduction

Section summary

This section outlines the PT2030 workstream areas and the scope of this final impact assessment.

Division of the Pathway to 2030 workstream

1.1. The PT2030 workstream is one of four workstreams within the OTNR. In the PT2030 workstream, we set out the proposed approach for a holistic onshore and offshore network design. Our final decision on delivery models will apply to the projects in scope of the HND and HNDFUE.

1.2. A summary of the activities in this workstream was provided in our July 2021 consultation.[17]

Table 1: Pathway to 2030 workstream areas and the scope of this impact assessment

Workstream area	Comment
Generation map	Generation map has been developed and delivered.[18]
Holistic network design (HND) and the HND Follow-up Exercise (HNDFUE)	The HND was and the HNDFUE will be produced by the NGESO in accordance with the Terms of Reference (**ToRs**) and any other relevant legislative or regulatory obligations.[19]
Detailed network design (DND) onshore	The DND for onshore transmission assets will be produced by the Transmission Owners (**TOs**) in accordance with the ToRs and any other relevant legislative or regulatory obligations.[20] The DND onshore specifies the onshore Transmission Assets to be delivered.
Detailed network design (DND) offshore	The DND for offshore Transmission Assets will be produced by the generators in accordance with the ToRs and any other

[17] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[18] Offshore Transmission Network Review generation map
[19] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem, page 47
[20] Ibid. page 48

	relevant legislative or regulatory obligations. The DND offshore specifies the offshore Transmission Assets to be delivered.
Delivery models	**In this final impact assessment, we consider the options for the delivery of relevant offshore Transmission Assets.**

1.3. This final impact assessment considers the two delivery model options for non-radial offshore transmission assets which will be available to developers. It also considers the extension of the Early Opportunities AI policy to projects in the scope of this workstream. The October 2022 AI decision in the Early Opportunities workstream allows generators to recover capital expenditure that is economically and efficiently spent behalf of a later user, subject to the early-stage assessment and cost assessment process.[21] The gateway assessment process, mentioned in our May 2022 publication, will be integrated in the early-stage assessment development. From this point on, the process will be referred to as the early-stage assessment.

1.4. Whilst we have a final decision for the PT2030, this does not set a precedent for the delivery model(s) that can be adopted under the OTNR's Future Framework workstream, formerly called the Enduring Regime. Key policy decisions underpinning any Future Framework will be taken by the Department for Energy Security and Net Zero (**DESNZ**) with Ofgem playing a key role in delivery, alongside OTNR partner organisations, in line with their remits. We expect a government response document to the September 2021 Future Framework consultation to be published in due course.[22]

[21] Decision on Anticipatory Investment and Implementation of Policy Changes | Ofgem
[22] Offshore Transmission Network Review: Enduring Regime and Multi-Purpose Interconnectors (publishing.service.gov.uk)

2. Problem under consideration

Section summary

This section sets out the existing arrangements for developing offshore wind transmission assets, our rationale for intervention and the various policy objectives driving our decision-making process.

Existing arrangements

2.1. Ofgem is responsible for managing the competitive tender process through which offshore transmission licences are granted. In the developer led option, Ofgem determines the transfer value of the assets to be transferred to the OFTO[23], grants the offshore transmission licence to the OFTO following a competitive process, and regulates the OFTO's compliance with its obligations under the licence. In the OFTO build option, Ofgem would determine the OFTO at an earlier stage as the OFTO would also be responsible for the construction of the assets.

2.2. To date, all competitively tendered offshore transmission assets have been designed and built by the wind farm developers. Offshore connection applications need to progress through the NGESO-led Connection and Infrastructure Options Note (**CION**) process, which includes collaboration with the relevant TO. With developer input, the CION process determines the most economical and efficient onshore connection point. A revised connection offer is issued following the CION process, which may have a different connection point or date. Connections essentially develop in isolation from one another.

2.3. The CION approach will be adapted for PT2030 projects. The connection design and post-CION offers will be based on the outputs of the HND. This will be provided for in the updated connection contracts.

[23] The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 | Ofgem

Rationale for intervention

2.4. The current regime for developing and connecting offshore wind generation incentivises developers to connect individually, with competition used to reduce costs rather than promote coordination. It is now unlikely that the existing regime can deliver the current levels of ambition in the timescales required, in a way that is efficient for consumers and appropriate for coastal communities and the environment.

2.5. Under the current delivery model, developers have had the opportunity to coordinate the development of their assets with each other. One of the reasons why this has not happened to date is that generators effectively underwrite the risk of any delay to their connection. They are therefore incentivised to complete assets as quickly as possible so that there is no risk of stranded wind farm assets. This drives generators to find the fastest route to asset delivery, which does not naturally lead to seeking collaboration with others.

2.6. To date, developers have not been incentivised to undertake AI on behalf of future projects as there was no clear route to recover the AI as part of the final transfer value of the asset transfer to the OFTO. The potential later user whose project would benefit from the AI will not commit to making a financial contribution ahead of its final investment decision. This has been a significant barrier to the development of coordinated offshore infrastructure.

2.7. This workstream was tasked with deciding on the delivery model or models which are best suited to deliver the offshore transmission assets in the HND and HNDFUE. The introduction of any form of coordination must ensure balance is maintained between the pace of delivery required to meet the government's ambition of 50GW of offshore wind by 2030 and introducing changes as soon as practically possible to maximise social, economic and environmental benefits.

Policy objectives

Ofgem's duties

2.8. Ofgem's principal objective is to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or transmission systems.[24] The interests of such consumers are taken as a whole,

[24] Our powers and duties | Ofgem

including their interests in the reduction of greenhouse gases and in the security of the supply of gas and electricity to them.

2.9. In assessing the options, we consider that competition should be retained where it is practicable and in the interests of consumers to do so. Our statutory duty is to carry out functions under the Electricity Act, wherever appropriate by promoting effective competition.[25] Promoting effective competition can help to achieve our principal objective of protecting the interests of existing and future consumers. It can drive efficiency and innovation, resulting in cost savings that lower consumer bills and help to meet the government's decarbonisation targets at the lowest possible cost. The importance of competition is also reflected in the OTNR policy assessment criteria (Appendix 1).

Policy assessment criteria

2.10. Through the OTNR governance structures, project partners[26] have agreed a consistent set of policy assessment criteria that can be used across OTNR workstreams (Appendix 1). These serve as a tool for the OTNR project partners to aid the evaluation of policy choices at a high level and are intended to aid decision-making, as opposed to conducting detailed economic or engineering decisions at specific sites.

2.11. Since the start of the OTNR process, Ofgem and DESNZ have engaged stakeholders extensively. This includes multiple rounds of developer bilateral meetings, industry roundtable events and an OTNR industry expert group. This engagement has enabled us to explore key barriers to coordination in more detail with industry and take a wide range of views into account. Barriers and opportunities raised by industry have been considered with key OTNR project partners such as DESNZ, NGESO, TCE and CES.

Stakeholder engagement to date

2.12. We published our consultation on changes intended to bring about greater coordination in the development of offshore energy networks in July 2021.[27] The consultation closed in September 2021 and 74 responses were received. In January 2022, we provided an update on the consultation with summary of the responses, next steps and indicative

[25] Electricity Act 1989, (s.3A(1B))
[26] Offshore transmission network review - GOV.UK (www.gov.uk)
[27] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

timelines.[28] In May 2022, we published our minded-to decision to apply a very late competition generator build model to non-radial offshore transmission assets in scope of the workstream. We also consulted on the consequential arrangements that may be required to implement the delivery model. We received 29 responses. We also received feedback during the HND launch webinar in July 2022 and multiple bilateral meetings since the May 2022 publication.

2.13. In April 2022, we consulted on our Early Opportunities minded-to decision on AI and the implementation of policy changes to facilitate AI capital expenditure (**capex**) recovery for projects pursuing coordination. We received 18 responses. Feedback received demonstrated a broad agreement with our proposals regarding consumers sharing the risk associated with AI, the introduction of an early-stage assessment process and, to a lesser extent, the extension of user commitment arrangements to the potential later user(s).

2.14. In December 2022, we consulted on our revised PT2030 minded-to decision. The revised minded-to decision included late competition OFTO build as an option, along with very late competition generator build model, for the delivery of coordinated assets. We also consulted on the extension of the AI policy from the Early Opportunities workstream to the projects in scope of PT2030.

2.15. We received 22 responses in total. 17 responses agreed with our revised minded-to proposal to introduce an OFTO-build model for the delivery of non-radial offshore transmission infrastructure. Three broadly agreed, subject to the final arrangements. One disagreed, preferring instead a TO build model. 20 responses agreed with our revised minded-to proposal to extend AI policy from Early Opportunities to the projects in scope of the PT2030 workstream. One broadly agreed, with reservations concerning the final arrangements.

[28] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

3. Approach

Section summary

This section describes our iterative approach to the impact assessments. This section also outlines our determination of "importance" within the meaning of Section 5A of the Utilities Act 2000 with regards to this final impact assessment.

Options analysis steps and proportional approach

3.1. We outline below the steps we have taken to assess the options throughout our decision-making process:

a) We mapped out our options by working out the potential delivery parties (developers, OFTOs, TOs and NGESO) and the points where competition could be introduced (early, late, very late). In our July 2021 consultation, we proposed six different options.[29] Later, in our January 2022 update, we discounted the early competition models, partly due to the workstream's time constraints. We also introduced a seventh option, a developer designed-consented and OFTO built-operated model[30] and have considered the various roles, responsibilities, capabilities and incentives of the potential delivery parties.

b) Prior to assessing the options, we outlined our analysis related assumptions, uncertainties and risks. We assessed the various costs, including capex costs associated with delivering the workstream's targets. We also assessed the various delivery timescales assumptions related to our options analysis.

c) Next, we estimated the Earliest in-Service Dates (**EISD**) for: no competition, late competition and very late competition scenarios. We estimated the potential capex savings or increased costs these scenarios could cause. We calculated the potential cost of delays beyond the 2030 target year, in terms of carbon and option fee costs.

[29] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[30] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

We then compared the EISD and the savings/increased costs of the competition scenarios with the potential cumulative cost of delay.

d) For the harder to monetise costs, we assessed the importance of using competitive tendering in relation to our duties and obligations. Later, this assessment helped us discount the no competition scenario option.

e) We analysed the various options, utilising the delivery partner analysis, EISD, potential saving/cost increase scenarios and cost of delay, whilst factoring in the importance of using competitive tender processes.

f) The options analysis led to our minded-to decision that the very late competition generator build model would bring the most benefits, by being more likely to reach the PT2030 targets efficiently. Under the very late competition generator build model, generators deliver and construct the assets before they are tendered, therefore, the competition only focuses on the financing, operation and maintenance of the assets.

g) We considered the responses received to the May 2022 publication and mapped out common themes. Most of the responses wanted the expansion of options available for developers when delivering coordinated assets.

h) We considered what further options could be made available to developers for non-radial offshore transmission assets under PT2030 and whether to apply these, including the extension of the AI policy from our Early Opportunities workstream.

i) We revisited our calculation assumptions after the HND and the asset classification decisions were published. The number of non-radial offshore transmission assets was less than we had previously assumed for our calculations in the May 2022 publication: three out of the 21 assets were classified, following our asset classification process, as non-radial offshore transmission assets.

j) We reassessed what the delay costs in terms of carbon and option fees could be with only three non-radial offshore transmission assets.

k) We assessed the risks and opportunities for expanding the Early Opportunities AI policy for the projects in scope of the PT2030 workstream. We concentrated on the

fact that the assets were less speculative, larger and impacted on the wider network benefit.

l) We reassessed the addition of a late competition OFTO build model as an option. We used the revised delay calculations and assumptions in our analysis.

m) We considered the responses to the December 2022 publication and mapped out common themes in responses towards our revised minded-to decision. Based on the responses received and our accompanying analysis, we confirm that the revised minded-to decision is now our final decision on the delivery models for non-radial offshore transmission assets and the extension of the AI policy.

Monitoring and evaluation

3.2. Lessons learned from the development and implementation of the PT2030 workstream will be applied to the development of the Future Framework for the delivery of offshore transmission assets.

Determination of "importance" within the meaning of Section 5A of the Utilities Act 2000

3.3. Under Section 5A of the Utilities Act 2000 (**UA2000**), we are required to carry out an impact assessment when:

- we are proposing to do anything in connection with our functions as set out in the Gas Act 1986 or the Electricity Act 1989; and
- it appears that such proposal is important.[31]

3.4. Section 5A(2) of the UA2000 specifies the situations where a proposal is to be considered "important" for the purposes of determining whether an impact assessment should be carried out. This includes if the implementation of the proposal would have "a significant impact on:

- persons engaged in commercial activities connected with … the generation, transmission, distribution or supply of electricity[32]

[31] Utilities Act 2000 s5A(1)
[32] Utilities Act 2000 s5A(2)(c)

- the general public in Great Britain or in a part of Great Britain".[33]

3.5. Our delivery model final decision for the PT2030 workstream has a significant impact on persons engaged in the generation and transmission of electricity, or in connected commercial activities. It will also have a significant impact on the general public in Great Britain or part of Great Britain. Thus, we have determined it to be "important" in terms of Section 5A of the UA2000.

[33] Utilities Act 2000 s5A(2)(d)

4. Assumptions, Uncertainties and Risks

Section summary

This section considers the cost assumptions and estimated delivery timescales we used in our options analysis.

Our assumptions

Set up costs

4.1. Establishing the late competition OFTO build tender regime and cost assessment processes for non-radial offshore transmission assets will require some additional resources to be allocated within Ofgem. We do not expect this to be a significant resource requirement in relation to planned investments of non-radial offshore transmission assets.

Delay assumptions associated with different delivery models

4.2. In our May 2022 publication, we did not expect there to be delays if a very late competition delivery model was to be chosen. The consultation responses to this view were mixed which led us to reconsider this assumption. We adjusted our assumption to there being a potential one-to-two-year delay if the available options would not be expanded to include both the late competition OFTO build and the extension of the AI policy from the Early Opportunities workstream.

4.3. For the development of early competition models, we estimated a three-to-four-year delay. The early competition models would entail a competition prior to the development of the DND requiring an additional time for us to develop (up to 24 months) and then implement (a further 18 months) such an early tender process. This would interrupt project development with a potential hiatus of up to 42 months.

4.4. For the no competition model, we did not predict delays as there would be no tender process to develop and run. Given the scale and scope of existing business activities, we did however recognise that there could be delays if the TOs struggled to increase their organisational capacity in order to construct such a significant portfolio of assets within the required timeframes.

Potential cost savings with different competition models

4.5. With a very late competition model, assets being tendered have already been built. It is estimated that the total savings from Tender Rounds 1, 2 and 3 within the OFTO regime are between £628m and £1.149bn.[34] If a very late competition model were to be selected as the delivery model for non-radial offshore assets in scope of PT2030, similar level of savings could be realised, if compared to a no-competition model. We assumed that if we did not run a competitive tender, the savings that the current OFTO regime has achieved could not be realised.

4.6. The late and early competition OFTO build models could put downward pressure on transmission pricing because of increased scope for competition. We recognise the risk that capex cost saving estimates for the different, new competition models could vary between projects. We see the expansion of competition through new delivery models beyond the projects within the scope of PT2030, as the direction of travel. We referred to some estimates in our May 2022 publication which are now, in part, superseded. In this final impact assessment, we focus on providing the best options for developers to choose from to avoid delays.

Timescale for delivery of offshore transmission assets

4.7. We assumed that the assets would be constructed at the same speed irrespective of the entity which would deliver them. We estimated the construction window for the coordinated assets to be between 3-5 years. We reached this assumption based on the facts that all parties are likely to be procuring goods and services from a similar pool of suppliers – and therefore construction was likely to take the same length of time whether it was undertaken by OFTOs or generators.

4.8. We believe that our original assumption of a six-month period for developers to complete commercial negotiations for the delivery of coordinated assets was too optimistic. We now estimate that there could be a delay of up to one to two years in the delivery of non-radial offshore transmission assets if developers only have the very late competition generator build model available to them. The delay could be caused by developers negotiating AI spend or construction responsibilities, while avoiding sharing proprietary information with each other. The extension of options available to developers may help shorten the negotiation times and break potential deadlocks

[34] TR7 Generic Preliminary Information Memorandum (ofgem.gov.uk)

between developers or provide routes forward where project circumstances mean the very late generator build model is challenging.

Reduced number of non-radial offshore transmission assets

4.9. Our May 2022 publication's delay cost analysis was based on ~19GW being delivered through the HND. This includes the LR4 ~8GW and first ~11GW of ScotWind. The ScotWind figure was reached based on initial discussions with NGESO about ScotWind inclusion in the HND and delivery queues.[35]

4.10. The HND ended up facilitating the connection of 21.8GW of wind.[36] This included LR4, the first tranche of ScotWind and a small number of projects from previous leasing rounds. There was an additional 1GW of capacity which was subject to Celtic Sea leasing round outcomes.

4.11. The non-radial offshore transmission assets' capacity totals 5,400MW, around 15% of the HND's total 35,890MW of transmission assets. In our monetised impact calculations, we are using the 5,400MW figure to reflect the smaller number of non-radial offshore transmission assets, compared to the ~19GW used in the first draft impact assessment. We recognise that calculating delay figures with the 5,400MW figure, presumes the delay of all three non-radial offshore transmission assets.

4.12. In the monetised impact calculations, we also use the 5,400MW figure to represent the non-radial offshore transmission assets' capacity among the projects in the HNDFUE. We consider this to be a proportionate method for estimating delay costs as we do not have definite insight into the proportion of non-radial offshore transmission assets included in the HNDFUE at this point. This brings the total HND and estimated HNDFUE non-radial offshore transmission assets' joint capacity to 10,800MW. For a further breakdown of how these figures have been utilised in the delay calculations, please see Table 2 (section 8.7).

[35] Further information about ScotWind inclusion in the HND and NGESO thinking can be found on the related NGESO press release on 11 February 2022.
[36] The Pathway to 2030 Holistic Network Design | National Grid ESO

Risk of extending the AI policy

4.13. There may be circumstances in which non-radial offshore transmission infrastructure could be constructed by an initial user with the use of AI (as opposed to by the first and later users in a formal collaboration). If this facilitates the delivery of the non-radial offshore transmission assets under the HND or HNDFUE, there are benefits to consumers to underwrite the costs associated with the AI, until the later user connects. The non-radial assets are a key component in delivering the HND and HNDFUE, and the former has been estimated to lead to overall net consumer savings of approximately £5.5bn (capacity and constraint costs).[37]

4.14. The extension of AI principles to PT2030 would allow for a single developer, the initial user, to construct offshore transmission infrastructure appropriate for the needs of a project that will connect later. Building infrastructure which benefits a later user, with the help of the extended AI policy, may assist in avoiding delays and delivery risks associated with solely having commercial arrangements between multiple parties.

4.15. This is of particular use in situations where projects are on different timescales ensuring that one developer can proceed with its development should the later user have a later project development timeline or be delayed during the development process.

4.16. The publication of the HND has also shown that there are a number of non-radial offshore transmission assets which will be used for wider network benefit. These assets will not only be used for the transmission of power from offshore generation to shore, but also for facilitating the dispatch of power from north to south. In this case the later user is a TO rather than a second offshore wind farm. The ability for an offshore wind farm to use AI to complete these assets independently can facilitate timely delivery, especially where affected parties are working under different applicable licensing regimes.

4.17. Expanding our AI policy to the PT2030 workstream will mean that consumers will underwrite the costs associated with AI in projects in scope of the PT2030 workstream,

[37] The recommended design leads to an additional £7.6 billion of capital costs due to the additional offshore infrastructure. However, this is outweighed by the £13.1 billion savings in constraint costs that are expected to result from the additional network capacity this infrastructure provides. NGESO Cost savings are calculated over a 40-year asset life period, starting in 2030, using 2021 prices.

until such time as a later user connects to the system and in the situation where the potential later user does not connect or reduces the capacity of its project.

4.18. Given that the OFTO transfer value will have included the economic and efficient AI, consideration of two distinct issues is required in relation to the TNUoS charging methodology: the AI Cost Gap and the AI Risk. The AI cost gap relates to recovery of the AI element of the offshore generator Transmission Network Use of System (**TNUoS**) tariff in the period between the shared asset transfer to the OFTO and the point that the potential later user will start using the shared assets. Under the existing charging arrangements, the initial user would face the offshore generator TNUoS charges associated with the AI Cost Gap, as well as its own TNUoS charges. The AI policy extension has the AI Risk and AI Cost Gap to be allocated in accordance with the Early Opportunities policy option decision. Under this option, the risk that the potential later user never uses the shared assets is allocated to consumers.

4.19. We believe that there are a number of factors which mitigate consumers' exposure to underwritten costs. Firstly, the development of the HND and HNDFUE mean that the scope of shared infrastructure has in many cases already been determined. Should developers wish to come forward with voluntary coordination proposals, these will be considered but will be by reference to meeting the objectives of the OTNR. There is no expectation that the AI policy will be developed or applied to the highly speculative AI (eg undetermined or unknown future projects).

4.20. While our AI policy has consumers underwriting the costs associated with AI until such time as the later user connects, this period is not expected to be unduly lengthy for PT2030 assets. This is because of the centrally planned nature of the transmission infrastructure providing a clear scope on the assets required and the benefitting projects. LR4 projects which form part of PT2030 workstream have high option fees meaning that developers are incentivised to connect as quickly as possible, thereby minimising the period during which consumers will underwrite the AI costs.

4.21. As with Early Opportunities, we propose to extend user commitment arrangements to AI for the later user who will benefit from the shared infrastructure but who is not making capital investment upfront. As with Early Opportunities, we expect NGESO to bring forward the code modifications required to give effect to this and for these to progress through the normal code governance and industry processes for codes and standards modifications.

4.22. PT2030 is novel in the way offshore transmission will be delivered. We recognise that the coordination of development presents more challenges than has previously been seen in the development of point-to-point connections, including the need for developers to coordinate design, delivery and timescales. There may be circumstances where this coordination is difficult to achieve, and we are keen to ensure that there are options available to mitigate the risk of non-delivery.

5. Monetised costs and benefits

Section summary

This section considers the cost of potential delay of not expanding the options available to developers when developing coordinated assets included in the HND and the HNDFUE. The delay costs are calculated in terms of both option fees and carbon.

Cost of delay calculation differences between the impact assessments

5.1. In this final impact assessment, we combine various estimated costs stemming from both the draft impact assessment and the additional draft impact assessment. These documents were published as part of the May 2022 and December 2022 publications, respectively.

5.2. In the first draft impact assessment, we estimated the cost increases or decreases that no competition, early competition and late competition could bring, compared with the current very late competition model.

5.3. In the additional draft impact assessment, we also focused on delay costs. The additional delay costs outlined in those impact assessments were derived from developers being drawn into extended negotiations to reach coordination agreements where very late competition generator build was the only option available for the development of non-radial offshore transmission assets. We estimate that our expanded options, in terms of delivery models and the AI policy extension, could help avoid a one-to-two-year delay caused by these lengthy negotiations. For our estimates, we used the reduced number of non-radial offshore transmission assets (which was reduced as a result of the HND and subsequent asset classification process) and their potential delay costs in terms of carbon and option fees.

More delay resulting in more annual option fee payments

5.4. Projects in both ScotWind and LR4 pay option fees to CES and TCE, respectively. ScotWind projects pay a single fee when they enter an option to lease – this secures the option for ten years. In contrast, LR4 projects pay an annual fee from the time they enter an option to lease until the developers obtain final planning permission.

5.5. When we look at the costs associated with delays, it is important to consider costs associated with option fees. The longer developers take to reach coordination agreements with each other, the longer the annual option fees accrue under the terms of the LR4 lease agreements.

5.6. Developers may be hoping that they can recover the option fee costs through their bids into the relevant Contracts for Difference (**CfD**) auctions, otherwise the option fees will be a significant sunk cost for the developers. We would expect that some, if not all, of the option fee costs would be passed on to consumers through developers' higher bids in the CfD auctions. This in turn could raise consumers' bills. Although we cannot be certain about developers' commercial strategies, and that all of these increased costs would be passed through to consumers, it is reasonable to assume some level of cost pass-through will occur. Therefore, a reduction in option fee costs would be classified as a potential benefit for energy consumers. Option fees are a transfer from developers (and potentially ultimately consumers) to TCE and HM Treasury.

5.7. In the HND, the proportion of LR4 projects was higher than ScotWind projects. This means that the impact of delay is higher in terms of the option fees payable because LR4 projects have annual option fees. In the HNDFUE, the proportion of ScotWind projects is higher than LR4 projects.

Cost of delay in carbon

5.8. Our final decision on delivery models and the AI policy extension to PT2030 projects will, we believe, help avoid a potential one-to-two-year delay in which developers are drawn into lengthy coordination negotiations. These delays could slow the connection to the grid of offshore wind.

5.9. These delays would in turn delay the displacement of thermal generation connected to the grid, something in which offshore wind will play a key role. In valuing emissions for appraisal purposes, the government places a value on carbon, based on estimates of the abatement costs that will need to be incurred to meet specific emissions reduction targets.[38] This is calculated by assuming that each MWh of new offshore generation would displace generation at the average grid carbon intensity, based on

[38] Valuation of greenhouse gas emissions: for policy appraisal and evaluation - GOV.UK (www.gov.uk)

DESNZ emissions factors and projected carbon pricing values.[39] We use the grid average because we are considering a significant amount of wind power, which would likely displace more than just the marginal generator (which usually has higher emissions), and so our approach avoids overestimation of benefits. The estimates use low and high load factor estimates.[40] These are discounted, marginal abatement values which used central carbon values.

[39] Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal

[40] The low load factor based estimates were reached using a web tool (Wind, v1.1, Europe, 1980-2016 dataset) developed by Iain Staffell and Stefan Pfenninger from Imperial College London and ETH Zürich (Staffell and Pfenninger, 2016). The tool estimates the average load factor for future wind turbine models on a GB offshore average based on 1980-2016 wind data. The high load factor estimates used BEIS provided load factors (fixed and floating, mixed technologies used median of the two load factors) for LR4 CfD allocation framework (Annex 3).

6. Non-monetised costs and benefits

Section summary

This section focuses on the importance of competition and the effects of the decision on energy security and wholesale energy prices.

The use of competitive tendering in delivery

6.1. Competitive tendering has benefits in a range of areas. While it is difficult to quantify all the impacts of opening markets up to competition, it can reduce costs, increase innovation and introduce new products, services and technologies.[41]

6.2. We have a duty to carry out our functions in the best way calculated, to further our principal objectives and wherever possible, promote effective competition where it can deliver benefits to consumers (whether that be in terms of cost or time savings or wider benefits). The benefits could also be in terms of introducing innovation or cost discovery.

Increasing energy security by reducing risk of delay

6.3. We are seeking to reduce the risk of delay and non-delivery of non-radial offshore transmission assets. Expanding the options available to developers can help do this. Delivery of the PT2030 network assets is essential in meeting the government's ambition of 50GW of offshore wind by 2030. This will help reduce GB reliance on fossil fuels and reduce exposure to the volatility of international fossil fuel prices which are beyond our control.[42] This also has the potential to reduce our wholesale market costs, as offshore wind has a low marginal cost when compared to other types of generation.

[41] Early Competition Plan Cost Benefit Analysis Consultation November 2022 Please see appendix 2 for examples. We recognise that some the examples do not directly refer to offshore competition.
[42] Major acceleration of homegrown power in Britain's plan for greater energy independence - GOV.UK (www.gov.uk)

7. Excluded options

Section summary

The section considers the options which our analysis has considered within the impact assessment and policy process but ultimately excluded. This section explains why the early competition, TO centric and no-competition options were excluded. The exclusion process utilised stakeholder feedback, delay calculations and the OTNR policy assessment criteria.

Exclusion of alternative options

7.1. Throughout the policy development process, we have excluded various alternative delivery models and options. The excluded options included early competition models, TO design and construction models and no-competition models.

Exclusion of early competition models

7.2. Following our initial analysis, the January 2022 update outlined our decision to focus on those models which do not involve a competition prior to the detailed network design process.[43] We considered that the early competition models would not work within the PT2030 delivery timeframes due to the development and implementation time required. Additionally, there was only a small number of consultation responses which preferred an early competition model for the projects in scope of PT2030. In the responses to the May 2022 publication, the feedback was consistent in that early competition models were not appropriate for this workstream due to time constraints.[44]

7.3. We assessed that the implementation of an early competition model could cause a three- to four-year delay in achieving the PT2030 targets. Models entailing a competition prior to the development of the DND would require additional time for us to develop and implement a tender process. We estimated that development of the

[43] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[44] Minded-to Decision and further consultation on Pathway to 2030 | Ofgem

tender process could take up to 24 months and implementation a further 18 months. This would interrupt project development with a potential hiatus of up to 42 months.

7.4. In a late competition or very late competition model, the DND and pre-construction work could happen in parallel while we would prepare changes to facilitate a late tender process. This parallel working would not happen in an early competition model. This means that early competition models may put at risk delivery of the 50GW offshore wind target by 2030.

7.5. Given the significant estimated delay, we ruled out two options of early competition. In the first option, the incumbent TO or the NGESO would carry out the detailed design for any shared infrastructure, prior to a competitive tender process to appoint an OFTO to consent, build and operate the assets. In the second option, there would be a competitive tender process for the appointment of an OFTO, after the HND has been completed. The appointed OFTO would be responsible for undertaking the DND, consenting, financing, construction, and operation of the non-radial offshore transmission assets.

Exclusion of 'TO design' and 'TO design and build' delivery models

7.6. In our July 2021 publication we laid out two options, a 'TO build – OFTO own' and a 'TO design – OFTO build and own' option. The first option required the incumbent TOs to undertake the DND, consenting and construction and an OFTO being tendered for the operational phase. The second option would require the incumbent TOs to undertake the DND and consenting, while an OFTO would be tendered to construct and operate the assets.

7.7. Some respondents to the July 2021 publication questioned the TOs' experience delivering offshore transmission and whether they were suitably incentivised to deliver on time. They also raised concerns about the robustness of any competition if the TOs were allowed to bid for projects they had taken part in developing.[45]

7.8. Selecting one of these delivery model options would have involved creating a new regime where TOs would design and consent the non-radial offshore transmission assets. The TOs would have to transfer the assets to an OFTO, whether before or after construction. The TOs do not have experience in designing, consenting or transferring

[45] For summary of consultation responses, see Appendix 2 in Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

assets in this context. Developing this new type of regime could cause delays to the projects within the scope of the PT2030 workstream.

7.9. Onshore reinforcements, which TOs have experience of building and owning, function in a different way compared to the OFTO regime. These two delivery model options would have involved an increased number of interfaces between involved parties. The TOs would have to confer with the developers with regards to their offshore wind farms, the NGESO with regards to the HND and the OFTOs at the point of transfer, along with the consenting bodies.

7.10. TOs have experience with assets physically located offshore, with complex network designs, and with supply chain engagement. The TOs will continue to build on this experience as the asset classification process for the HND resulted in six assets being classified as onshore assets.[46] TOs may face scalability challenges to increase their organisational capacity in order to construct such a significant portfolio of assets within the required timeframes, given the scale and scope of their existing business activities. This concern was supported by a number of consultation responses.[47]

7.11. The late competition OFTO build model forms a part of a package of choices for developers to choose from. This differs from these two TO centric models which would have been applied to all non-radial offshore transmission assets. We did not judge such a blanket approach to the assets to be appropriate at this time.

Exclusion of no-competition delivery models

7.12. Competition has a key role to play in driving innovative solutions and efficient delivery that can help us meet our decarbonisation targets at the lowest cost to consumers. We recognise that since 2009, we have successfully applied competition to reduce the costs of offshore electricity transmission. It is estimated that the total savings from Tender Rounds 1, 2 and 3 within the Offshore Transmission Owner regime are between £628m and £1.149bn.[48] If a no-competition model was selected as the delivery model for non-radial offshore assets in scope of PT2030, there would likely be substantial cost savings which would not be realised.

7.13. This would contrast with our OTNR policy assessment criteria (2b, Renewable generation competition impact, Appendix 1) and our primary duties. Ofgem's objective

[46] Offshore Transmission Network Review: Decision on asset classification | Ofgem
[47] July 2021 consultation responses: Mainstream Renewable Power, p. 8; Elia Group, p.5
[48] TR7 Generic Preliminary Information Memorandum (ofgem.gov.uk)

is to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or transmission systems.[49] In carrying out our functions in relation to electricity and gas systems, where appropriate, we will promote effective competition to ensure that the interests of consumers are protected over time.

7.14. We estimate a delay to the 2030 targets to be less likely in the no competition scenario, due to the lack of inter-developer negotiations and OFTO tender processes. A partial risk of delay exists due to the TOs having to cover a large portfolio of non-radial offshore transmission assets in both HND and HNDFUE, as well as their onshore reinforcement assets specified in the designs. We want to avoid combined cost increases resulting from delayed projects and the no competition scenario.

[49] Our powers and duties | Ofgem

8. Options analysis

Section summary

The section considers the counterfactual scenario of proceeding only with very late competition generator build model for non-radial offshore transmission assets, without the expansion of policy options. The section also considers alternative discounted delivery model options. The section considers the factual options of the final decision. The first option being the application of AI policy to the PT2030 workstream. The second option being the inclusion of the late competition OFTO build model for the delivery of non-radial offshore transmission assets in the scope of the PT2030 workstream.

Counterfactual and factual scenarios

8.1. We considered counterfactual and factual scenarios for delivery of the non-radial offshore transmission assets:

- Counterfactual: we proceed with only the very late competition generator build delivery model for non-radial offshore transmission assets within the scope of this workstream, without the extension of the AI policy or the availability of a late competition OFTO build model.

- Factual: we give developers expanded options for non-radial offshore transmission assets within the scope of this workstream:

    - working collaboratively with other developers using a very late competition generator build model; **or**
    - using AI in the very late competition generator build model; **or**
    - opting to use a late competition OFTO build model for the delivery of non-radial offshore transmission assets.

Counterfactual

Delivery of assets in counterfactual scenario

8.2. In the counterfactual scenario, we proceed solely with the very late competition generator build delivery model for non-radial offshore transmission assets within the scope of this workstream. The offshore generators sharing the non-radial offshore transmission assets would together undertake the DND, consenting and construction of those assets, as included in the HND and HNDFUE. A competitive tender process would be carried out to transfer ownership of operational assets to an OFTO. This process would require the generators to develop the assets together or to commercially agree that one of them would develop the assets on behalf of the other one.

8.3. In the first draft impact assessment, we estimated that this scenario would not lead to any significant delays. We previously estimated that it would take developers six months to reach coordination agreements with each other.

8.4. In response to the May 2022 publication, developers stated that they foresaw challenges with this option. The respondents challenged the assumptions we made about the length of time it would take for commercial negotiations to conclude between coordinating developers. The respondents believed that it would take significantly longer than 6 months.

8.5. They indicated that it would potentially be very challenging to coordinate without the extension of the AI policy and further delivery model options being available. Without an expanded package of options, developers could be drawn into lengthy formal cooperation negotiations causing the projects to be delayed beyond the 2030 target. These factors combined could potentially result in cases of non-delivery of the non-radial offshore transmission assets.

8.6. Taking on board this feedback, we revised our assumption as to the length of time negotiations for developer coordination would take. In the case of solely a generator-build option for the delivery of non-radial offshore transmission assets, we estimate a one-year delay to be likely and two years of delay to be somewhat likely.

8.7. After the publication of the HND and the application of the asset classification process, the non-radial offshore transmission assets account for 5.4GW of capacity, instead of

the 19GW utilised in the first draft impact assessment. The first draft impact assessment assumed that the HND would be wholly non-radial assets. The first year of delay in terms of discounted carbon costs is now estimated at £147m-237m and two years is estimated at a cumulative £267-429m. We estimated that the first year of delay, in terms of discounted option fees, would result in ~£351m costs, being paid by developers in aggregate to TCE and HM Treasury. For two years of delay the figure would cumulatively increase to £679m.

Table 2: Discounted delay cost estimates (in millions, GBP) for the May 2022 publication, the updated HND and HNDFUE figures.

Discounted delay cost estimates (in millions, GBP)	Likely delay to 2031 if options not expanded	Somewhat likely delay to 2032, if options not expanded
May 2022 – cumulative option fees delay (all LR4 included)	£645	£1,268
May 2022 – low carbon scenario (19GW)	£521	£963
May 2022 – high carbon scenario (19GW)	£819	£1,513
Cumulative option fees delay (partial LR4 included)	£351	£679
Low carbon scenario (5.4GW)	£147	£267
High carbon scenario (5.4GW)	£237	£429
Option fees + Low carbon (5.4GW)	£499	£946
Option fees + High carbon (5.4GW)	£588	£1,108
HND + HNDFUE low carbon (10.8GW)	£295	£535
HND + HNDFUE high carbon (10.8GW)	£473	£859
HND + HNDFUE low carbon (10.8GW) + option fees (partial LR4)	£646	£1,213
HND + HNDFUE high carbon (10.8GW) + option fees (partial LR4)	£825	£1,537

Factual scenario

8.8. We now consider that providing increased options alongside our initial proposal of coordinated generator-build is the best way to ensure that projects are constructed on time and that the government's 2030 ambitions for offshore wind can be met. We will do this by expanding the application of AI policy to the PT2030 workstream and by including a late competition OFTO-build model as a delivery option.

Expansion of the Early Opportunities AI policy to the PT2030 workstream

8.9. As part of the Early Opportunities workstream we issued a decision to allow for recovery of AI by developers.[50] We have also decided on how the costs and risks associated with the AI should be allocated between consumers and the users of the AI. The recovery of AI will be subject to an early-stage assessment to determine if it meets the objectives of the OTNR. Recovery of the AI costs via the final transfer value at the asset transfer to the OFTO will be subject to a cost assessment process.

8.10. The decision on Early Opportunities AI policy included:

- Allocation of AI risk between the consumer and later user(s) of shared transmission infrastructure developed under the Early Opportunities workstream.
- Introducing the early-stage assessment for developers.
- Extension of user commitment arrangements to the potential later user of AI funded offshore transmission infrastructure.

8.11. The Early Opportunities analysis indicated that the use of AI in the development of coordinated infrastructure was likely to result in a net benefit to consumers.

8.12. Consumers will underwrite the risk of the AI in advance of the later user(s) connecting to coordinated assets. The charges in respect of the AI spend will accrue until that point of connection and will be for the account of the later user when they connect. If the later user fails to connect, charges which would have otherwise been paid in respect of the AI element will not be recovered and will therefore effectively remain with consumers.

8.13. This analysis was supported by a report commissioned from the technical advisory firm DNV. The report considered the estimated capex values for the offshore transmission infrastructure required for the connection of two generic offshore wind generators based on either separate connection assets or shared connection assets.[51] In the coordinated scenario, the initial user develops and installs assets that would

[50] Decision on Anticipatory Investment and Implementation of Policy Changes | Ofgem
[51] Offshore Coordination - Early Opportunities: Consultation on our Minded-to Decision on Anticipatory Investment and Implementation of Policy Changes | Ofgem
The DNV report is available in the draft impact assessment's Appendix 2.

also be used by the potential later user. Two generator designs are considered in the report: Design 1 and Design 2, which are summarised in Table 3.

Table 3: Generic offshore wind farm design specifications

Policy option	Project 1 capacity (MW)	Project 2 capacity (MW)	Project 1 cable length from OFTO offshore substation to landfall (km)	Project 1 cable length from landfall to OFTO onshore substation (km)	Project 2 cable length from OFTO offshore substation to landfall (km)	Project 2 cable length from landfall to OFTO onshore substation (km)
Design 1	500	400	50	20	60	20
Design 2	800	800	55	20	65	20

8.14. The report's analysis showed that for both designs, the coordinated scenario leads to significant savings in the total capex of the transmission system(s). The report's Design 1 achieves a 30% saving from £417m to £293m, and Design 2 achieves a 17% savings from £564m to £468m (see Table 4).

Table 4: Estimated total capital costs of offshore transmission assets for two generators in counterfactual and coordinated scenarios

	Counterfactual (£m)	Coordinated (£m)	Savings (%)
Design 1			
Total offshore transmission capex	417.4	293.3	30%
Design 2			
Total offshore transmission capex	564.2	467.9	17%

8.15. The report suggested that the use of AI would result in an indicative net benefit to consumers of £14.6m if the later user connects and uses the shared assets. This figure excludes potential additional benefits that may flow from generators to consumers through any reduction in CfD allocation round clearing price due to other capital cost savings.

8.16. If the potential later user fails to connect and use the assets, with no recovery of user commitment amounts from the potential later user, the modelled net cost to consumers in this example is £138m. The workstream proposed to implement the early-stage assessment process to manage this risk to consumers and proposing the extension of user commitment arrangements to mitigate the cost to consumers if the later user fails to connect.

8.17. The HND has shown that coordinated non-radial offshore transmission assets could be delivered by a single developer carrying out AI works on behalf of a later user. Should PT2030 developers opt to use AI policy, they will have a route to the recovery of the AI related capex in the same manner as that envisaged in the Early Opportunities workstream. This recovery route is facilitated via the transfer sum paid to the developer by the OFTO following the cost assessment process.

8.18. Expansion of the AI policy encourages developers to build coordinated assets by providing a route to recovery of economic and efficient costs of the AI. The extension of the AI policy can help developers deliver coordinated offshore transmission assets without the need to conclude formal commercial arrangements with the other users of that shared infrastructure. Forming these commercial arrangements could be particularly challenging where projects are on different timescales. Allowing for the use of AI in place of more formal collaboration arrangements (such as joint ventures) may help save time and help deliver the assets within the scope of the PT2030 workstream in line with the government's 2030 ambition.

8.19. We expect the risk of the later user failing to connect is lower for the projects in scope of the PT2030 workstream compared to the projects in the Early Opportunities workstream. This is because of the centralised design aspects of the HND and HNDFUE. As the HND indicates (and the HNDFUE will indicate) the most suitable assets for the offshore coordination, this helps to reduce the risk of unnecessary AI spend. This contradicts with the Early Opportunities projects that are coordinating on a more voluntary basis.

8.20. We recognise that the coordinated assets involved in the HND and HNDFUE will potentially require larger amounts of investment than the voluntary coordination-based assets in the Early Opportunities workstream. The larger assets are a key component in delivering the HND design which is estimated to lead to overall net

consumer savings of approximately £5.5bn (capacity and constraint costs).[52] The AI policy is an effective mechanism to help deliver the coordinated assets which forms part of the HND, including infrastructure providing wider network benefits.

Inclusion of very late competition generator build delivery model option

8.21. We anticipate that some projects will find formal commercial agreements, including joint ventures, as the most suitable option when developing non-radial offshore transmission assets. Throughout the OTNR process, developers have, in general, expressed their preference towards retaining control over the development of the transmission links to their projects and limiting interfaces between delivering parties. Developers have also highlighted their track record of delivering radial offshore transmission assets in the GB market.

8.22. Developers face strong incentives to complete the DND and pre-construction phases as quickly as possible to avoid delays in connecting their projects. Similarly, developers are strongly incentivised to develop a cost efficient DND, as the capex of the project affects their TNUoS charges. Because of the structure of the OFTO regime, developers are incentivised to ensure that the construction of the offshore transmission assets are delivered to a high standard. This would apply to both radial and non-radial coordinated transmission assets.

8.23. Offshore generators have experience in building offshore transmission assets and in general have a strong natural incentive to deliver on time since the transmission infrastructure is their route to market. Generators also have a strong inherent incentive in relation to cost efficiency, reflecting that the offshore assets inform the TNUoS that the generator will pay. We also undertake a cost assessment process and may disallow costs which we deem have not been economically and efficiently incurred.

Inclusion of late competition OFTO build delivery model option

8.24. The late competition OFTO build option would require generator(s) to undertake the detailed design and consent of the coordinated assets, with the subsequent appointment of an OFTO to construct and operate them following a competitive tender

[52] The recommended design leads to an additional £7.6 billion of capital costs due to the additional offshore infrastructure. However, this is outweighed by the £13.1 billion savings in constraint costs that are expected to result from the additional network capacity this infrastructure provides. NGESO Cost savings are calculated over a 40-year asset life period, starting in 2030, using 2021 prices.

process. A similar option exists in the radial OFTO regime, although to date it has not been selected by developers.

8.25. There is a possibility that the development of the late competition OFTO build option could result in some delays. However, we consider this option to effectively mitigate against the risk of non-delivery by providing more optionality and flexibility to suit project-specific circumstances.

8.26. Ofgem has in the past considered various late competition OFTO build tender frameworks which enable the OFTOs and generators to have varying degrees of control over procurement and construction management.[53] Stakeholder engagement and decisions regarding the make-up of late competition OFTO build model for non-radial transmission assets will take place in 2023.

8.27. Providing a late competition OFTO model allows developers to select the most appropriate delivery model for the non-radial offshore transmission infrastructure for their projects. This option could ease coordination pressures in the post-consenting phases of development. It gives developers another option if they are not able to advance coordinated assets by way of agreed collaboration. Late competition OFTO build also provides another route to delivery if a developer does not wish to fund until asset transfer the capex requirements to meet the AI required for the shared assets if they used the generator build model. For example, a developer may prefer not to use AI where the cost of the necessary AI is considered too high to be risked by a single developer.

8.28. We recognise that the late competition OFTO build option still includes a level of coordination between developers. As the number of users of GB waters increases, some level of coordination between participants will be an essential part of the offshore industry going forward. We do not see working in complete isolation to be a viable route forward when it comes to developing offshore assets. Cooperation between developers can help minimise the economic, environmental and local community impacts of the new infrastructure that will be required.

[53] OFTO Build: Providing additional flexibility through an extended framework | Ofgem

8.29. We recognise that we will need to develop the process for the late competition OFTO build model, including the details of the tender process, and associated tender guidance and cost assessment documents.

8.30. We had previously identified that the development of the late competition OFTO build regime for non-radial offshore transmission assets could lead to delays for projects within the scope of this workstream. Due to the number of non-radial offshore transmission assets identified in the HND being lower than we had initially assumed, the impact of potential delay associated with the development of this model is reduced. This means that the cost of delay, stemming from the further development of any delivery model option, is lower than we had initially modelled (see section **Error! R eference source not found.**). In general, we see the direction of travel being competition being brought forward to earlier stages of development of non-radial offshore transmission assets, although we are not developing an early competition model with regards to tight timeframe projects within the scope of PT2030.

8.31. Late competition OFTO build has recognised potential benefits. In our May 2022 publication analysis, we did not deem the benefits to be sufficient for us to adopt this option. These benefits were weighed against the potential delay costs calculated for the 19GW of potential non-radial offshore transmission assets (see Table 2). Because there were fewer non-radial offshore transmission assets in the HND than originally assumed, the cost of delay is less than we initially expected. We now propose to include this model as part of the expanded package of options. This option will increase developers' delivery options, to address possible issues around non-delivery or delays.

8.32. Late competition OFTO build provides an option for cases where there is sensitivity on the sharing of confidential or proprietary information with a competitor or where they fail to reach a commercial agreement (or where reaching such agreement would take longer than alternative options). Developers would still have to agree on seeking the late competition OFTO build which can, after failed negotiations, be a more attractive option than non-delivery.

8.33. Even with the introduction of AI as an additional option to facilitate the delivery of shared infrastructure, a generator build option may not be feasible. This could be the case if there is no natural lead developer among the affected projects or where no developer is willing to fund the AI on behalf of another project.

8.34. A late competition OFTO build model could provide financial benefits which help balance costs caused by any delay in the delivery of non-radial offshore transmission assets. These benefits are speculative as we have not run a late competition OFTO build before. Although, as noted previously, costs and benefits are reduced due to the smaller number of non-radial offshore transmission assets having been determined through the asset classification process.

8.35. An OFTO build model can put downward pressure on transmission pricing because the late competition may allow alternative and extended financing routes. This can offer more choice for funding solutions as well as different funding providers for transmission asset construction. This is underpinned by an existing offshore transmission regime including an A-rated counterparty in NGESO, an established OFTO equity and debt funding market and strong public sector institutional support.

8.36. OFTOs would be enabled to take a whole life approach to transmission investment to deliver an overall cost of capital which is potentially competitive relative to generator build. The model can provide early clarity and certainty for generators on future capital expenditure and network charges. The model would allow generators to focus on their core business, in accordance with the generator's capability, capacity and risk appetite for involvement in offshore transmission. The model can also introduce additional transmission specialists into the GB market.

Table 5: Some of the advantages and disadvantages of initial and preferred options

Initial option	Advantages	Disadvantages
Very late competition generator build **without** the use of AI extension policy	• The very late competition option includes OFTO competitions which can bring savings to consumers. • The policy helps avoid the three- to four-year delay, caused by policy development and competitive design production hiatus, associated	• This option could result in a one-to-two-year delay due to extended negotiations between developers. The delay could cost up to £825m-£1,537m in terms of additional carbon and option fee costs (8.8).

	with the early competition models.	• Both the initial and preferred options include a level of coordination between developers and adjusting to the new coordination environment can cause a level of uncertainty among developers.
Preferred option	**Advantages**	**Disadvantages**
Very late competition generator build **without** the use of AI extension policy	• This options, as part of a package of options, helps avoid the three- to four-year delay, caused by policy development and competitive design production hiatus, associated with the early competition models.	• We recognise that the options still include a level of coordination between developers and adjusting to the new coordination environment can cause a level of uncertainty among developers.
Very late competition generator build **with** the use of AI extension policy	• The expanded AI policy, coupled with the two delivery model options, can help avoid extended negotiations between coordinating generators. Avoiding a one- to two-years of delay caused by these negotiations can help avoid up to £825m-£1,537m in terms of additional carbon and option fee costs (8.7). • The use of AI helped save 17% and 30% in total capital costs in two coordinated test scenarios, when compared with the counterfactual scenario of no coordination.	• The risk associated with AI are shared between the consumer and later user(s) of shared infrastructure. The AI Cost Gap will be allocated to the later user(s) of shared infrastructure. Consumers will underwrite the AI Cost Gap in advance of the later user(s) connecting to shared infrastructure and in the situation where the potential later user(s) does not connect at all. We proposed to implement the early-stage assessment process to manage this risk to

		consumers and proposing the extension of user commitment arrangements to mitigate the cost to consumers if the later user fails to connect.
Late competition OFTO build	• OFTO build provides another route to delivery if a developer does not wish to fund the capex for AI, until asset transfer, under the generator build model. • OFTOs could take more of a whole-life approach to the assets, managing both construction and operation.	• There is a possibility that the development of the late competition OFTO build option could result in some delays. However, we consider this option to effectively mitigate against the risk of non-delivery by providing more optionality and flexibility to suit project-specific circumstances.
Overall impact of these three options	• The delivery models options include OFTO competitions which can bring savings to consumers. • Successful policy package can facilitate lower CfD bids due to lower capital spend due to coordination (8.15). • Delivering coordinated assets is a key component in delivering the HND design which is estimated to lead to overall net consumer savings of approximately £5.5bn (capacity and constraint costs) (8.20).	• Both the initial and preferred options include a level of coordination between developers and adjusting to the new coordination environment can cause a level of uncertainty among developers.

9. Appendices

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Appendix 1: Policy Assessment Criteria

Through the OTNR governance structures, project partners have agreed a consistent set of Policy Assessment Criteria that can be used across OTNR workstreams. The serve as a tool for the OTNR partners to aid the evaluation of policy choices at a high level, as opposed to detailed economic or engineering decisions at specific sites. They are intended to aid decision making. There are four overarching themes: Deliverability of OTNR policy and Net Zero; Economics and Commercials; Environmental and Societal Impact; and Consumer and System impact. While they were designed to be consistent with relevant wider objectives such as the Government's Ten Point Plan for a Green Revolution10 and organisational duties, it is for the relevant decision-making body to use the results of any policy assessment based on these criteria when making decisions in accordance with relevant objectives and duties. To this end, Ofgem will use the assessment criteria to shape policy options and evaluate options but will be steered by its statutory duties to make decisions that are in the best interests of consumers.

- Purpose is to a) translate policy aims of the review into specific set of criteria for policy options and b) provide a common way of considering and comparing options within a workstream, subject to resourcing proportionality and consistency with relevant public bodies' strategic aims and statutory duties.

- Intend to use the same criteria for all workstreams and include interactions between the workstreams where necessary.

- In general, our approach to assessment will be consistent with prevailing good practice, for example the Green Book and Impact Assessment guidance where relevant.

- We do not intend to numerically weight criteria, and a balance will need to be struck by decision makers. Some criteria may be more important in one workstream than another.

- Criteria are intended for evaluating policy choices (eg high level design of enduring regime, delivery options for pathway to 2030), not for detailed economic/engineering decisions at specific sites (eg placing a cable route from A to B or A to C).

- Initially they will be used largely qualitatively, with an expectation of more detailed quantitative work when appropriate for specific workstreams

- All options compared to **baseline of uncoordinated point to point solutions** for each site. An uncoordinated solution for the purposes of this pack means a connection provided as per industry processes and requirements as they had effect on 13 January 2021. The descriptions used by the NGESO for 'integrated' and 'status quo' models will be used to support options assessments where appropriate. Please refer to the NGESO Phase 1 Report, page 17, Table 1. Ref: download (nationalgrideso.com)

- They are a tool for aiding decision making. They are intended to be consistent with relevant wider objectives (such as the 10 point plan and offshore wind supply chain) and duties (such as Ofgem's statutory duties). They are not intended, in themselves, to set policy or minimum standards, for example in respect to environmental requirements. It is for the relevant decision making authority to utilise the results of our assessments when making decisions in accordance with its objectives and duties.

1. Deliverability of OTNR policy and Net Zero			
#	**Name**	**Description**	**Notes**
1a	Deliverability	Policy can be delivered in a timely and proportional fashion for the workstream	• Two aspects to this – delivery of policy/regulatory change, and deliverability of the policy option (for the transmission infrastructure itself and users connecting into it) • Not a binary answer – ability to deliver is dependent on several factors including organisations involved, scope and timeline • Qualitative assessment – is it even possible to make these changes (policy change, regulatory change, industry governance), and to do so sufficiently quickly? • Is the delivery model, overall regime, and timing feasible given other constraints, eg technology readiness, onshore network reinforcement, environmental legislation? • Qualitative assessment – can it be done in time to affect the projects it intends to? How complex is the change? • Is the development process sufficiently simple that developers/stakeholders can understand, navigate and use it in practice?
1b	Decarbonisation	Supports decarbonisation/NZ agenda ie, total/speed of emissions reduction	• Option must support the achievement of net zero greenhouse gas emissions • Carbon impact of transmission infrastructure, plus link to deployment impact, and may impact curtailment • Does it enable 40GW of offshore wind by 2030? • Does it help or hinder other potential offshore technologies eg hydrogen, CCUS
2. Economics and commercials			

#	Name	Description	Notes
2a	Deployment impact	It speeds up deployment of offshore wind compared to an uncoordinated solution	• Could deployment be sped up through a coordinated approach to grid connection? Could it also reduce or increase (risk of) delays through planning and consenting? • Integrated solution may delay some as they 'wait' for it, but speed up others if it gives a ready made route to shore (eg prior to getting seabed lease) • Combining some process steps (or streamlining) may speed up whole development process • Deployment impacts may also include cost-effectiveness, safety (in terms of safety and integrity of system eg reliability), flexibility (does it lock in design/tech earlier or later than current regime?)
2b	Renewable generation competition impact	Maintain an effective competitive regime and level playing field for different actors in renewable generation	• OSW competition (eg increased or decreased by certain types of process integration) • Minimise competitive distortions (eg in CfD bid, in bearing costs of AI, timing and delays impact) • Maintain an effective competitive regime and level playing field for different actors • Note that potential for reform (eg of CfD, of market) can increase complexity and uncertainty, which may be detrimental to competition • Impact on competition is on a spectrum, not a binary outcome
2c	Transmission competition impacts	Increases, or does not decrease or distort, competition in transmission	• Delivery model for shared/coordinated transmission infrastructure may impact competition. For example, a model with less competition than current regime may be preferred if it enables other aims such as speed of deployment. Equally other models may increase competition, such as earlier-stage competition for offshore transmission infrastructure. • Potential knock-on impacts on onshore reinforcement and onshore competition regime • How the model makes sure parties involved in transmission have the skills and capabilities to deliver • Impact on competition is on a spectrum, not a binary outcome
2d	Risk allocation	Places risks on those best placed to manage them	• Is risk being placed with those best able to manage it? Is risk being allocated fairly? • Does the policy option materially increase/decrease project delivery risk? Eg by how it impacts liabilities, control etc. Including who bears the risk (and associated financial impact to transmission owner, generators and other transmission users) of delays in completion of transmission infrastructure. One way these risks manifest is through the FID for generation and transmission • 'Project' here can refer to offshore wind, offshore transmission or interconnectors (or other variants and technologies where appropriate) • Risks include but are not limited to delays, costs, decommissioning • Level of clarity and transparency for who bears risk

3. Environmental and Societal Impact			
#	**Name**	**Description**	**Notes**

3a	Environmental (non-carbon) impact	Significant impacts on the environment are avoided, minimised or mitigated by coordinated transmission	• Includes offshore and onshore environmental impacts, for example AONB, SSI. • Reduced volume of assets but remainder are larger in size and may involve more 'crossings' of other infra assets • Marine constraints per TCE study – biodiversity, physical environment, historical environment, other subsea/infra, • When applying these criteria in practice, consideration must be given to the impact on Marine Protected Areas (MPAs) in order to minimise adverse impacts that might later risk or delay consent." We note a number of requirements flowing from legislation (eg habitats regulations, Marine and Coastal Access Act) must be factored into any policy framework. • Regional environmental impacts (eg peatland in Scotland) • Cable impacts can include cable installation, sand wave clearance, external cable protection impacts.
3b	Local Communities Impact	Impact and mitigation on local (including coastal) communities impacted by construction of 'onshore' assets and related activity	• Encompasses onshore and offshore communities, including sea users (such as fishing) and wider onshore communities hosting strategic grid infrastructure • Potential benefits including job creation, utilisation of local supply chains, and impact of compensatory measures • Key concerns typically relate to: the number and size of onshore connection points and onshore infrastructure; cumulative impacts associated with multiple connections, substations and other infrastructure; onshore transmission reinforcements driven by offshore infrastructure connections; and the lack of co-ordination between wind farm proposals. Co-ordinated/ consolidated/ integrated infrastructure is central to mitigating impacts. • Concerns about impacts relate to: visual impact; proximity to residential areas (socio-economic impacts) and built environment impacts (including heritage/ listed building impacts); impacts on environmentally protected and/or sensitive areas (ecological and visual impacts); lack of use of brownfield sites (use of which could be mitigation); noise, traffic and transport during construction in particular; additional local socio-economic and tourism impacts, particularly during construction.

4. Consumer and system impact			
#	**Name**	**Description**	**Notes**
4a	End-consumer net benefit	Has a positive impact on consumer savings	• Consumer savings (or additional costs), most notably through lower offshore T costs and hence lower CfD pricing (or market pricing eg, cPPA), but also wider savings/costs. • Note that in principle impacts such as impact on onshore investment, curtailment, balancing costs, financing costs (ie, WACC) could be factored into this analysis as part of a Cost-Benefit Analysis. In practice a proportionate approach must be taken in the time available. • AI risk could be borne by the end-consumer - cost where any investment is not needed (either temporarily or permanently) • Note may also be non-monetary impact to all GB consumers of a more/less reliable network.

Appendix 2: Glossary

A

Anticipatory investment (AI)
Investment that goes beyond the needs of immediate generation, reflecting the needs created by a likely future project, projects or the wider transmission system.

B

BEIS
Department for Business, Energy & Industrial Strategy

BESS
British Energy Security Strategy

C
capex
Capital expenditure

CES
Crown Estate Scotland

CfD
Contracts for Difference

CION
With developer input, the CION process determines the most economical and efficient onshore connection point.

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. In this document, 'Developer' is also used to refer to developers of electricity interconnectors.

DESNZ
Department for Energy Security and Net Zero

E

Electricity Act
The Electricity Act 1989 as amended from time to time.

Early-stage assessment
Early-stage assessment being developed for both Early Opportunities and PT2030 workstream projects. The early-stage assessment assesses the projects' anticipatory investment proposals.

NGESO
National Grid Electricity System Operator

G

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.

H

HND
Holistic network design, which will identify the requirements for network capacity on the NETS across GB onshore and in offshore waters to efficiently connect projects within the scope of the PT030 workstream.

HNDFUE
Holistic Network design follow-up exercise. It is the follow up to the HND.

L

LR4
Leasing round 4 is the Crown Estate led offshore seabed leasing round which offers the opportunity for at least 7 GW of new offshore wind projects to be developed in the waters around England and Wales.

O

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

OFTO
Offshore transmission owner

OFTO Build
A model for the construction of Transmission Assets. Under this model, Ofgem runs a tender to appoint an OFTO with responsibility for constructing and operating the Transmission Assets.

OFTO Cost Assessment Guidance
Guidance document that sets out the cost assessment process that Ofgem follows to determine the transfer value for an offshore transmission system.

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.

OTNR
The Offshore Transmission Network Review (OTNR) was launched to ensure that future connections for offshore wind are delivered with increased coordination while ensuring an appropriate balance between environmental, social and economic costs.

P

PT2030

The Pathway to 2030 forms part of the Offshore Transmission Network Review. It aims to develop the regulatory framework to allow the optimum engineering solution to connect 50GW of offshore wind to the system by 2030.

S

ScotWind

ScotWind is a Crown Estate Scotland led offshore seabed leasing round. ScotWind is the first Scottish offshore wind leasing round in over a decade and the first ever since the management of offshore wind rights were devolved to Scotland. 20 projects have been offered option agreements which reserve the rights to specific areas of seabed.

T

TCE

The Crown Estate

Tender Regulations

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

TO or Transmission Owner

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

ToRs

Terms of reference, to clarify the network design objectives of the PT2030 workstream of the Offshore Transmission Network Review.

Transmission Assets

Defined in Paragraph 1(3)(a) of Schedule 2A to the Electricity Act as the transmission system in respect of which the offshore transmission licence is (or is to be) granted or anything which forms part of that system.

TNUoS

Transmission network use of system. TNUoS charging arrangements reflect the cost of building, operating and maintaining the transmission system.