DRAFT IMPACT ASSESSMENT

Draft impact assessment on Pathway to 2030 workstream's minded-to 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:	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		

Summary

This document is a draft impact assessment (IA) that sets out our assessment of the minded-to decision for the delivery model for the Offshore Transmission Network Review (OTNR) Pathway to 2030 workstream.

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

The current frameworks relating to developing and connecting offshore wind generation need to be reviewed in light of the government's expectations for offshore wind. In 2019, the government stated[1] its ambition of achieving a significant increase to 40GW in offshore wind capacity by 2030 from the current level of around 10GW. In April 2022, the Prime Minister announced a new British Energy Security Strategy, which built on previous offshore wind targets, to set an ambition of 50GW of offshore wind by 2030.[2] We do not consider that individual radial offshore transmission links[3] for this amount of offshore generation are likely to be economical, sensible or acceptable for consumers and local communities.[4]

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

The objective of the OTNR is to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, 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 while ensuring an appropriate balance between environmental, social and economic costs. The OTNR is now transitioning from reviewing to reforming, as we publish decisions and begin to implement the regulatory and planning changes necessary to deliver a coordinated transmission network. The objective of the Pathway to 2030 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 one project from an earlier leasing round. We will work with industry and stakeholders to provide clarity on the delivery model for Celtic Sea in future.

[1] Queen's speech December 2019 background briefing notes (publishing.service.gov.uk)
[2] British Energy Security Strategy (publishing.service.gov.uk)
[3] To date, offshore windfarms in GB have been connected to the shore via standalone transmission links. With more offshore windfarm projects planned, many of which are further from shore than those developed already, there is potential for efficiencies from greater coordination of offshore transmission infrastructure.
[4] Ofgem decarbonisation programme action plan

Ofgem's principal objective

Our principal objective is to protect the interests of existing and future consumers and it is important to note that these interests are taken as a whole, including consumers' interests in the reduction of greenhouse gases and the security of the supply of gas and electricity to them. This workstream aligns to our new strategic framework and its programme to enable investment in low carbon infrastructure at a fair cost.

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

This IA considers seven potential delivery model options for the transmission assets within the scope of the Pathway to 2030 workstream. The models vary based on whether and when a competition is held and which parties design, gain consent, construct and operate the assets. We assessed the developers, Transmission Owners (TOs), the Electricity System Operator (ESO) and Offshore Transmission Owners (OFTOs) as potential delivery partners at the varying development phases. The options for delivering non-radial offshore transmission are compared with a generator led very late competition model (as to date no developer has elected to use OFTO build) and assume that a radial connection would be used. Based on our analysis, weighing aspects such as delivery timelines, estimated costs of delay and considering the strengths and weaknesses of potential delivery bodies, we determined the generator-build very late competition model to be the optimal delivery model for non-radial offshore transmission and therefore the 'Preferred Option'. This IA has been published alongside our publication setting out our decision on radial offshore transmission, our minded-to decision on non-radial offshore transmission and a further policy consultation on how we propose to implement our minded-to decision.

Summary table of delivery model options and delivery phases

Phase 1	**Holistic network design**
Phase 2	**Detailed network design**
Phase 3	**Pre-construction (eg consenting)**
Phase 4	**Construction**
Phase 5	**Operation**

Delivery model option	**Phase 1**	**Phase 2**	**Phase 3**	**Phase 4**	**Phase 5**	**Main effects on Consumer outcomes**	**Key considerations** (Risks, assumptions, distributional impacts etc.)
1. TO build and operate	ESO	TO	TO	TO	TO	Potentially increased costs due to lack of competition.	This model does not include competition.
2. TO build > OFTO operate	ESO	TO	TO	TO	OFTO	Less likely to deliver 2030 targets without costly delay.	Uncertainty over TOs' incentives and expertise in delivering offshore transmission assets by the 2030 goal.
3. TO design > OFTO build and operate	ESO	TO	TO	OFTO	OFTO	Less likely to deliver 2030 targets without costly delay.	Running a late competition could cause costly delays. Uncertainty over TOs and OFTOs' incentives and expertise in delivering assets by the 2030 goal.
4. Early OFTO competition	ESO	ESO or TO	OFTO	OFTO	OFTO	Unlikely to deliver 2030 targets without costly delay.	Early competition would likely require a significant hiatus in project development and delivery while a tender process is designed and then implemented. Uncertainty over TOs and OFTOs' incentives and expertise in delivering assets by the 2030 goal.
5. Very early OFTO competition	ESO	OFTO	OFTO	OFTO	OFTO	Unlikely to deliver 2030 targets without costly delay.	Early competition would likely require a significant hiatus in project development and delivery while a tender process is designed and then implemented. Uncertainty over TOs and OFTOs' incentives and expertise in delivering assets by the 2030 goal.
6. Developer design and build > OFTO operate	ESO	Offshore generator	Offshore generator	Offshore generato r	OFTO	More likely to deliver the 2030 targets without costly delay.	Most likely delivery model to reach the 2030 goals while providing benefits of competition.
7. Developer design > OFTO build and operate	ESO	Offshore generator	Offshore generator	OFTO	OFTO	Less likely to deliver 2030 targets without delay.	Running a late competition could cause costly delays. Uncertainty over OFTOs incentives and expertise in delivering assets by the 2030 goal.

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 was the Net Benefit monetised, NPV or other (*eg NPV calculated using 2016 as base year. Economic costs and benefits are in 2015 financial year prices covering the period from 2016 to 2020*).

Table 7, NPV calculated using 2022 as base year. The NPV considers the discounted cumulative cost of delay beyond 2030 in terms of carbon and additional annual option fees. The NPV covers the potential savings or cost increases of the no competition, late competition and early competition models when compared with the very late competition model. The competition models are compared with the cost of delay beyond 2030. We considered one-to-two years of delay under a late competition model to be possible, while a three-to-four-year delay under early competition model to be probable. Our NPV calculations display that the cost of delay outweighs the benefits of running a savings providing late or early competition. The calculations also highlight the importance of running a very late competition as the no competition model could lead to cost increases even without a delay.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetise impacts, including mid-term strategic and long-term sustainability factors following Ofgem IA guidance. Our preferred option was selected based on balancing tested savings methods provided by the very late competition model, timely delivery of the necessary infrastructure required by 2030 – and facilitating government's offshore wind targets by 2030 – with potential savings that might be delivered through different delivery models. Competitive tendering has benefits in a range of areas. It is difficult to quantify all the impacts of opening markets up to competition. Increasing innovation and introducing new products, services and technologies are possible benefits of competitive tendering but these benefits are dynamic and hard to measure. Very late competition has the benefit of insulating the OFTO from construction risks. This can attract low cost of capital for the operational phase. Earlier achievement of targets could increase GB energy security by reducing our exposure to volatile fossil fuel markets. Earlier achievement of targets reduces the risk of high energy prices. The preferred model helps achieve legally binding targets in a more timely fashion.

Section 5 sets out the assumptions used in our assessments for this IA. • We assumed that delivering the 19GW covered by the HND to cost around £15bn. This includes Leasing Round 4 (LR4) and the first tranche of ScotWind. • We estimated the development of new regulations based on slow (16 months) and fast policy (24 months) development scenarios for the Workstream. • We assumed that running a competition process would take between 18-24 months across all of the delivery models where competition is applied. • We assumed that every entity would deliver the assets at the same speed. We estimated the delivery window for the coordinated assets to be between 3-5 years. • We assumed that there would be at least six months of commercial negotiations between developers if one of the developer competition models was adopted.

Will the policy be reviewed?	As the enduring regime is being developed, we will look to apply any lessons learned from the development and implementation of the Pathway to 2030 workstream.

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

Contents

1. Introduction

Section summary

This section outlines how the Pathway to 2030 workstream is divided and what is the scope of this IA.

1.1. The current approach to designing and building offshore transmission was developed when offshore wind was a nascent sector and industry expectations were as low as 10GW by 2030. It was designed to de-risk the delivery of offshore wind by leaving the project developers in control of building the associated transmission assets to bring the energy onshore. This approach has contributed to the maturing of the sector, the significant reduction in costs of offshore wind energy and has helped position the UK at the forefront of global offshore wind deployment.

1.2. The OTNR was launched in July 2020 with the objective to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, considering the increased ambition for offshore wind to achieve net zero. This aims to find the appropriate balance between environmental, social and economic costs.

1.3. The Prime Minister's Ten Point Plan for a Green Industrial Revolution in November 2020 set an ambitious offshore wind target of 40GW by 2030.[5] In April 2022, the Prime Minister announced a new British Energy Security Strategy, which built on previous offshore wind targets to set an ambition of 50GW of offshore wind by 2030.[6]

1.4. The Pathway to 2030 workstream is one of four workstreams within the OTNR. In the Pathway to 2030 workstream, we set out the proposed approach for a holistic onshore and offshore network design. We are specifically seeking to capture the current ScotWind and Crown Estate Leasing Round (LR4) projects.

1.5. A summary of the activities and projects-in-scope of the Pathway to 2030 workstream ('the workstream') was provided in our July 2021 consultation.[7]

[5] The Ten Point Plan for a Green Industrial Revolution (publishing.service.gov.uk)
[6] British energy security strategy - GOV.UK (www.gov.uk)

[7] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

Table 1 Pathway to 2030 workstream areas and the scope of this IA

Workstream area	Comment
Generation map	Generation map has been developed and delivered.[8]
Holistic network design (HND)	The HND will be produced by the ESO in accordance with the Terms of Reference (ToRs) and any other relevant legislative or regulatory obligations.[9]
Detailed network design (DND) onshore	The DND for onshore transmission assets will be produced by the TOs in accordance with the ToRs and any other relevant legislative or regulatory obligations.[10]
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 relevant legislative or regulatory obligations. The DND offshore specifies the offshore Transmission Assets to be delivered.
Delivery models	**In this draft IA, we consider seven options for the delivery model to be applied to the relevant offshore Transmission Assets.**

1.6. The delivery model to be applied is the focus of this IA. We considered the benefits and costs to consumers of seven delivery model options. We have developed this draft IA in accordance with our IA guidance.[11] This IA has been published alongside our publication setting out our decision on coordinated radial offshore transmission, our minded-to decision on non-radial offshore transmission and a further policy consultation on how we propose to implement our minded-to decision.

1.7. Whilst we have a minded-to decision for the Pathway to 2030, this does not set precedent for the delivery model(s) that can be adopted under the Enduring Regime and the most appropriate delivery models will be considered as part of Ofgem's wider development of competition in networks. Key policy decisions underpinning any future Enduring Regime would be recommended by BEIS with Ofgem playing a key role in delivery, alongside OTNR partner organisations, in line with its remit. We expect a

[8] Offshore Transmission Network Review generation map
[9] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem, page 47
[10] Ibid. page 48
[11] Impact Assessment Guidance | Ofgem

Government Response document to last year's Enduring Regime consultation to be published in due course.[12]

[12] 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 rational for intervention and the various policy objectives driving our decision-making process.

Existing arrangements

2.1. The current regulatory regime for offshore transmission was launched in 2009 and uses competitive tenders to select and licence Offshore Transmission Owners (OFTOs) to own and operate the assets that connect offshore wind farms to the onshore network.

2.2. To date, all competitively tendered offshore transmission assets have been designed and built by the wind farm developers. The assets are then transferred to an OFTO following a competitive tender process, which will determine who will own, operate, maintain and decommission the transmission assets. We refer to this as the 'Generator Build' model.

2.3. Ofgem determines the value of the transmission assets to be transferred to the OFTO, by calculating the economic and efficient costs which ought to be, or ought to have been, incurred in connection with developing and constructing the transmission assets.[13]

2.4. Connecting offshore applications need to progress through the Connection and Infrastructure Options Note (CION) process, which, with developer input, 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.

[13] Offshore Transmission: Guidance for Cost Assessment (2022)

Roles and responsibilities in the existing arrangements

2.5. In this section, we describe the relevant roles and responsibilities of offshore wind developers, OFTOs, the ESO, transmission owners (TOs) and Ofgem under the existing arrangements.

Offshore wind developers

2.6. Offshore wind developers are responsible for obtaining the necessary agreements and consents for the development and construction of offshore wind projects, including the associated offshore transmission assets. Alternatively, the generator could use the OFTO build option. Under this scenario the developer would obtain the connection agreement and undertake high level design and preliminary works before seeking the appointment of an OFTO. The OFTO would be responsible for the construction and operation of the offshore transmission.[14] This option has not been exercised by the developers.

Offshore Transmission Owners (OFTOs)

2.7. In the generator build option, following a competitive tender, OFTOs own and operate the offshore transmission assets that connect offshore wind farms to the onshore electricity transmission system. To date, the OFTO regime has attracted significant investor interest from capital markets, commercial banks and equity sponsors.

2.8. Alternatively, under the OFTO build option, as mentioned above, the OFTO would be responsible for the construction and operation of the offshore transmission assets.[15] This option has not been exercised by the generators.

2.9. The transmission of electricity is a licensable activity under the Electricity Act.[16] OFTO licences impose obligations, incentives and entitlements on the OFTO.[17] The licence is broadly comprised of two parts. One part sets out the standard conditions which apply to all transmission owners. The other part sets out the conditions which are modified to meet the circumstances of each transmission business. In the OFTO licence, the modified conditions include a licence condition that adjusts the OFTO's revenue

[14] The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 (ofgem.gov.uk)
[15] The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 (ofgem.gov.uk)
[16] Electricity Act 1989 (section 4)
[17] Guidance on the offshore transmission owner licence for Tender Round 8 (TR8) (ofgem.gov.uk)

depending on asset availability, rather than actual utilisation or wind farm availability. It also places obligations on the OFTO to maintain the assets in line with good industry practice.

Electricity System Operator (ESO)

2.10. The ESO leads the process through which offshore generators and interconnectors connect to and make use of the transmission system. As part of the connection offer process, the ESO manages the CION optioneering process in collaboration with the developer and relevant TO to identify the overall economic and efficient connection option for each specific project.

Transmission Owners (TOs)

2.11. The TOs provide connection offers and necessary onshore network reinforcements. The relevant TO is responsible for the design of the connection and the infrastructure of its transmission system, provision of charging and capital cost information to the ESO, initial outage requirements, programme of works, asset details, and the issuance of the TO construction offer to the ESO.[18]

Ofgem

2.12. 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[19], and grants the offshore transmission licence to the OFTO, and regulates the operation of the OFTO asset. In the OFTO build option, Ofgem determines the OFTO at an earlier stage as the OFTO would also be responsible for the construction of the assets. This option has not been exercised by any generator.

Rationale for intervention

2.13. As noted above, the existing arrangements were developed when offshore wind was a nascent sector and industry expectations were just 10GW by 2030. In light of new ambitious offshore wind targets, radial offshore transmission links are not likely to be economically and environmentally acceptable for many areas.

[18] STCP18-1 Connection and Modification Application, [STC Code Documents | National Grid ESO]
[19] [The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 | Ofgem]

2.14. The current approach to designing, building and connecting offshore wind farms was developed when the technologies involved were at the early stages of deployment at scale. Regulation was designed to de-risk the delivery of offshore wind by providing project developers with the option of building the associated transmission assets to bring the energy onshore. To date, the existing offshore regime has connected 10.4 GW of offshore wind to the Great Britain electricity system; a third of the world's installed offshore wind capacity.

2.15. The length of time taken to develop an offshore wind farm is substantial. From seabed leasing, through connections, planning and consenting processes to CfD auction and OFTO tender, the offshore wind journey requires significant commitment of time. It can take up to ten years, and in many cases longer, for a project to move from securing an option to lease seabed to commercial operation. Further, the design of the connection is often determined relatively early in the process and thus, changes to ongoing projects especially those far along in the development process, can carry substantial risk to project success.

2.16. 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 uncertain whether 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. There are significant environmental and social benefits to a more coordinated approach, as the number of new electricity infrastructure assets, including cables and onshore landing points, could be reduced.

2.17. Under the current delivery model, developers have had the opportunity to coordinate their assets among each other more closely, but this has not happened. Generators effectively underwrite the risk of delayed assets and they are incentivised to complete assets as quickly as possible so that there is no risk of stranded wind farm assets.

2.18. To date, developers have not been incentivised to undertake anticipatory investment (AI) on behalf of future projects without a clear route to be able to reclaim that AI as part of the final transfer value of the asset transfer to the OFTO, following a cost assessment process. The potential later user whose project would benefit from the AI will not commit to making a financial contribution ahead of a final investment decision. This has been a significant barrier to the development of coordinated offshore infrastructure.

2.19. As the HND will take into account AI, we consider a review of the existing cost assessment guidance is appropriate. We note previous feedback within our 2020 consultation to ensure that we work with developers to ensure a greater level of certainty can be delivered.[20] This is another factor we will consider in undertaking any review. For avoidance of doubt, we will provide an updated cost assessment guidance document, prior to any tender round commencing.

2.20. The workstream was tasked with deciding on the delivery model which is best suited to deliver the HND and the more coordinated transmission infrastructure. We considered seven different options which are outlined in Section 4 and further analysed in the subsequent sections.

2.21. Under options 1 to 5 and 7, the generator would be reliant on another party to deliver transmission assets in a timely manner to ensure they are ready for power to be exported from the offshore wind farm as soon as they are completed. This will depend on the design of the shared infrastructure as a result of the HND. In option 6 the developer would have similar control over timelines as they do today, they would also be responsible for the timely delivery of infrastructure to other projects (which may or may not be owned by the same developer) or of wider network benefit. This means that any delay might not only affect them but might affect other developers too.

2.22. The implementation of any of these options must properly take account of the competence and incentives of the party designing and building the assets, and also take account of project timelines, ensuring that there is adequate provision for running a competition (where there is one) and providing sufficient time for construction. The regime must incentivise timely and efficient delivery of transmission assets, potentially including appropriate penalties for late delivery.

2.23. Therefore, the introduction of any form of coordination will be a balancing act between maintaining the pace of delivery required to meet the government's ambition of 50GW by 2030 and introducing changes as soon as practically possible to maximise social, economic and environmental benefits.

[20] Offshore Transmission Owner (OFTO) Regime Tender Process – Consultation concerning the developments to the current tender process | Ofgem

Policy objectives

Ofgem's duties

2.24. 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.[21] The interests of such consumers are their interests taken as a whole, including their interests in the reduction of greenhouse gases in the security of the supply of gas and electricity to them.

OTNR and Pathway to 2030 workstream objectives

2.25. The objective of the OTNR is to ensure that the transmission connections for offshore wind generation are delivered in the most appropriate way, 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 while ensuring an appropriate balance between environmental, social and economic costs.

2.26. The objective of the Pathway to 2030 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 one project from an earlier leasing round. We will work with industry and stakeholders to provide clarity on the delivery model for Celtic Sea in future.

OTNR policy assessment criteria

2.27. Through the OTNR governance structures, project partners[22] 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, as opposed to detailed economic or engineering decisions at specific sites. They are intended to aid decision-making.

2.28. There are four overarching themes: Deliverability of OTNR Policy and Net Zero; Economics and Commercials; Environmental and Societal Impact; and Consumer and

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[21] Our powers and duties | Ofgem

[22] Offshore transmission network review - GOV.UK (www.gov.uk)

System Impact. While they were designed to be consistent with relevant wider objectives such as the Government's Ten Point Plan for a Green Revolution[23] 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. The Policy Assessment Criteria are provided in an Appendix 1.

Competition

2.29. In assessing the options, we consider that competition should be retained where it is practicable and in the interests of consumers to do so.

2.30. 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 Government's decarbonisation targets at the lowest possible cost. The importance of competition is also reflected in the OTNR Policy Assessment Criteria (Appendix 1).

Stakeholder engagement in assessing policy

2.31. Since the start of the OTNR process, Ofgem and BEIS have engaged stakeholders extensively. This includes through multiple rounds of developer bilateral meetings, industry roundtable events and an OTNR industry expert group. These engagements have 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 the Electricity System Operator, the Crown Estate, and Crown Estate Scotland.

2.32. We published our consultation on changes intended to bring about greater coordination in the development of offshore energy networks in July 2021.[24] The consultation closed in September 2021 and 74 responses were received. In January 2022 we provided an

[23] The Ten Point Plan for a Green Industrial Revolution (publishing.service.gov.uk)
[24] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

update on the consultation with summary of the responses, next steps and indicative timelines.[25]

[25] 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 outlines the importance for the impact assessment, our approach to the assessment and next steps, including the concurrently published consultation and our impact monitoring and evaluation plan.

Our approach to assessing impacts

Determination of "importance" within the meaning of s5A of the Utilities Act 2000

3.1. Under s.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.[26]

3.2. 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[27]
- the general public in Great Britain or in a part of Great Britain".[28]

3.3. Our delivery model minded-to decision for the workstream has a significant impact on persons engaged in the generation and transmission of electricity, or in connected commercial activities. The minded-to decision will also have a significant impact on

[26] Utilities Act 2000 s5A(1)
[27] Utilities Act 2000 s5A(2)(c)
[28] Utilities Act 2000 s5A(2)(d)

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.

Options analysis steps and proportional approach

3.4. Here is an outline of the steps we took to determine the most suitable delivery model for the non-radial assets, as outlined by the HND:

a) We mapped out our options by working out the potential delivery partners (developers, OFTOs, TOs and ESO) and the points where competition could be introduced (very early, early, late, very late). In our July 2021 consultation, we proposed six different options.[29] Later, in our January 2022 update, we discounted the very early and 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 partners.

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, early 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.[31] Afterwards, we compared the EISD and the savings/increased costs of the competition scenarios with the potential cumulative cost of delay.

[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
[31] The delay scenarios ranged from one to five years, with the delayed earliest-in-service dates ranging from 2031-2035. The LR4 projects have to pay significant option fees annually with the projects' annual fees totalling ~£879m, ~£668m if discounted. ScotWind projects, as opposed to LR4 developers, a single fee when they enter an option to lease, this secures the option for ten years.

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

f) The options analysis led to our minded-to decision that the Generator Build – very late competition model would bring the most benefits, by being more likely to reach the Pathway to 2030 targets efficiently.

Monitoring and evaluation

3.5. As the enduring regime is being developed, we will look to apply any lessons learned from the development and implementation of the Pathway to 2030 workstream.

4. Options

Section summary

This section considers the seven delivery model options for the Offshore Transmission Assets required to connect the offshore wind generation within the scope of Pathway to 2030. This section also sets out our counterfactual scenario.

Delivery model options

4.1. In this section we define what we mean by radial and non-radial solutions and describe the seven delivery model options that we considered.

Definition of radial and non-radial solutions

4.2. The delivery model options would be applied where the Holistic Network Design (HND) indicates a requirement for a Transmission Asset other than a sole use radial solution.

4.3. Where the HND indicates that a sole use radial solution would be the most economic and efficient solution, the solution would be delivered through either the existing OFTO-build or generator-build options under the current OFTO regime. Further details on how we reached this decision can be found in the minded-to decision and consultation document.

4.4. For the purposes of this workstream, we consider a radial solution is a transmission system which fulfils both of the following criteria:

- Infrastructure used for transmission in an area of offshore waters of electricity generated by a *single* generating station in such an area and,

- Infrastructure connecting a *single* offshore generating station directly to a point on the transmission system owned by a transmission owner. This point could be located either onshore or offshore spatially and its designation (as onshore or offshore) will be determined by its primary function electrically (as opposed to its location).

4.5. We consider a non-radial solution is a transmission system, which fulfils both of the following criteria:

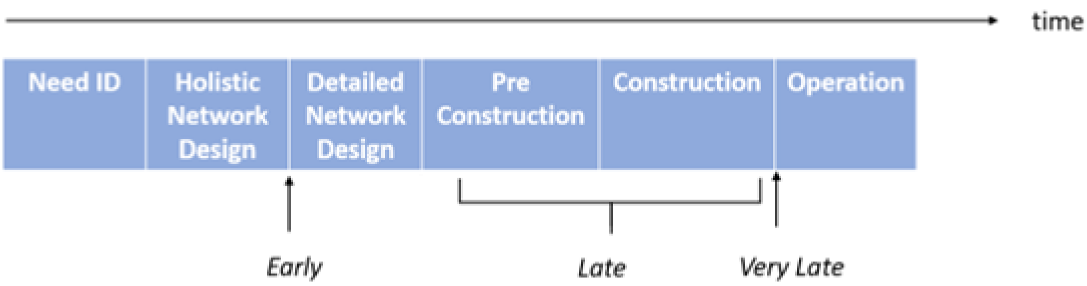
- Infrastructure used for transmission in an area of offshore waters of electricity generated by *two or more* generating stations in such an area.

- Infrastructure connecting a *two or more* offshore generating stations to a point on the transmission system owned by a transmission owner. This point could be located either onshore or offshore spatially and will be designated (as onshore or offshore) by its primary function electrically (not where it is located).

4.6. Non-radial offshore transmission is likely to involve two or more developers in its delivery.

4.7. Six out of the seven delivery model options include a type of competition. The options differ based on when competition occurs and who carries out the various development phases. The types of competition considered in this IA are: early, late and very late. Very late competition is run after assets have been constructed. Table 2 outlines the various types of competition.

Table 2 – Types of competition



Delivery model options for the development of non-radial assets

4.8. We considered seven delivery model options for the offshore Transmission Assets required to connect the offshore wind generation within the scope of Pathway to 2030. The delivery model options are summarised in Table 3, with hatched lines used to denote the point at which competition takes place in each option.[32] Models 2 to 7 all incorporate competition (ie, competition to determine the OFTO).

[32] For more detailed descriptions of the delivery model options, please see the July 2021 consultation for options 1 to 6 and the January 2022 update for option 7.

4.9. After the January 2022 analysis update, a further model (7) was added. Similar to model 3but entailed an offshore generator undertaking the DND and pre-construction work rather than a TO.

Table 3 Offshore delivery model options

Delivery model option	Holistic network design	Detailed network design	Pre-Construction (eg consenting)	Construction	Operation
1. TO build and operate	ESO	TO	TO	TO	TO
2. TO build > OFTO operate	ESO	TO	TO	TO	OFTO
3. TO design > OFTO build and operate	ESO	TO	TO	OFTO	OFTO
4. Early OFTO competition	ESO	ESO or TO	OFTO	OFTO	OFTO
5. Very early OFTO competition	ESO	OFTO	OFTO	OFTO	OFTO
6. Developer design and build > OFTO operate	ESO	Offshore generator	Offshore generator	Offshore generator	OFTO
7. Developer design > OFTO build and operate	ESO	Offshore generator	Offshore generator	OFTO	OFTO

The hatched lines represent the point in the development and delivery of a Transmission Asset, at which a competition is held.

4.10. **Option 1 – TO Build and Operate.** This model requires the incumbent TO to undertake the Detailed Network Design (DND), develop, construct and operate all shared infrastructure in their existing licence area, which includes the Renewable Energy Zone.[33]

4.11. **Option 2 – TO Build with OFTO Operate.** As with Option 1, this option requires the incumbent TO to undertake DND, develop and construct the shared infrastructure but would see an OFTO in place for the operational phase. Under this option, at or near asset completion, a tender process would be run to transfer ownership of the assets built by the TO to the OFTO. This would be a tender process similar to that run under the present regime (under the generator-build model) and is an example of a very late competition model.

4.12. **Option 3 – TO Design with OFTO Build and Operate.** This model would require the ESO to undertake the HND, the incumbent TO to undertake the detailed network design and consent the shared infrastructure, with the subsequent appointment of an OFTO to construct and operate it. This is an example of a late competition model.

4.13. **Option 4 – Early OFTO Competition.** This option would require the incumbent TO or the ESO to carry out the detailed network design for any shared infrastructure, prior to a competitive tender process to appoint an OFTO to consent, build and operate the assets. It should be noted that while the TOs have experience of detailed technical design of network assets, this would be a competence, the ESO would need to develop.

4.14. **Option 5 – Very Early OFTO Competition.** This option would see a competitive tender process for the appointment of an OFTO after the HND has been completed, with the appointed OFTO responsible for undertaking the DND, consenting, financing, construction, and operation of infrastructure.

4.15. **Option 6 – Developer design and build with OFTO operate.** This option is similar to the generator-build option used to date in the current OFTO regime. For shared infrastructure, as with the other options above, HND would be carried out by the ESO. After this, the offshore generator would undertake DND, consenting and construction of shared infrastructure and a competitive tender process would be carried out to transfer ownership of operational assets to an OFTO. This could require the offshore

[33] An area of sea outside the UK territorial sea over which the UK claims exclusive rights for production of energy from water and wind under section 84 of the Energy Act 2004. The boundaries of the REZ have been redefined so that they are largely consistent with the Exclusive Economic Zone (EEZ).

generator to oversee the development and construction of assets beyond those required for the first offshore wind farm.

4.16. **Option 7 – Developer design with build and operate OFTO.** This model would require generator(s) to undertake the detailed design and consent the shared infrastructure, with the subsequent appointment of an OFTO to construct and operate it. This is an example of a late competition model.

Counterfactual scenario

Summary of the counterfactual scenario

4.17. We considered a counterfactual scenario for the delivery of the offshore transmission assets required to connect the offshore wind generation within the scope of Pathway to 2030:

- Counterfactual: Generator led very late competition radial asset which does not consider coordination.

- Factual: Generator led very late competition of HND indicated non-radial assets or existing regime for HND indicated radial assets.

Delivery of assets in counterfactual scenario

4.18. The delivery model in the counterfactual scenario is based on the existing OFTO regime. Under this regime, offshore wind developers can develop and build the transmission assets and transfer the built assets to the OFTO identified through a tender exercise (the Generator Build option). Alternatively, the developer will obtain the connection agreement and undertake high level design and preliminary works associated with the offshore transmission assets before transferring these to an OFTO. The OFTO will then be responsible for the construction and ongoing operation of the offshore transmission assets (the OFTO Build option).[34] In summary, we would assume assets to be built in an uncoordinated and radial fashion as in the past.

4.19. Since the existing OFTO regime was launched in 2009, no offshore wind developer has chosen to use the OFTO build option. In their responses to previous OFTO regime

[34] The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 (ofgem.gov.uk)

consultations, developers have outlined some of the reasons why the OFTO-build option has not been exercised. Some developers were concerned that an OFTO build would lead to a loss of control over a critical component of their offshore wind projects. Developers were also worried about uncertainties regarding the identity and capability of the OFTO, the difficulties of joining up development timelines and the practical issue of having to incorporate long tender process early on in the project development timetable. They argued that these factors could increase the cost of capital through higher risk premiums or preclude positive investment decisions.[35] Similar concerns were echoed in the developers' responses to our July 2021 consultation.[36] Within the counterfactual scenario, we assume that the Generator Build option would continue to be chosen by offshore wind developers.

4.20. An overview of the delivery model in the counterfactual scenario is provided in Table 4. The table shows the absence of a holistic network design and that the built assets are transferred to an OFTO after a tender exercise.

Table 4 Delivery model in the counterfactual scenarios

Delivery model option	Holistic network design	Detailed network design	Pre-Construction (eg consenting)	Construction	Operation
Counterfactual	n/a	Offshore generator	Offshore generator	Offshore generator	OFTO

The hatched line represents the point in the development and delivery of a Transmission Asset, at which a competition is held.

[35] Offshore Electricity Transmission: Further consultation on the Enduring Regulatory Regime (August, 2010)
[36] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

5. Assumptions, uncertainties and risks

Section summary

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

Our assumptions

Capital and Operating costs

5.1. We compared previous projects' capex costs of past radial connections to calculate an average cost per megawatt of power (£ per MW). We reached a figure of ~£0.8m per MW to deliver the roughly 19GW of generation capacity that has been planned to be included into the HND.[37] With the average £/MW we estimated the capital costs of delivering the offshore transmission infrastructure needed by 2030 are ~£15.0bn. We estimate that the integrated and coordinated approach could provide £2.84bn in savings. This figure is reached by using the above mentioned ~£15.0bn figure and the ESO's integrated approach capex savings estimate rating of 19% (see section 5.4). Later in section 6 of this IA (Monetised costs and benefits) we map and compare these calculations onto the various competition models and costs of delay.

5.2. To calculate capex and opex cost assumptions, we used a combination of the ESO's Offshore Coordination Phase 1 Final Report's and our own calculations.[38] The Phase 1 Report includes one reference scenario for market development: the Leading the Way scenario from Future Energy Scenarios (FES) 2020.[39] Of the FES 2020 scenarios, only Leading the Way meets the government (then current) target of 40GW of offshore wind by 2030.

[37] This includes the Leasing Round 4 and first ~11GW of ScotWind. This figure was reached based on initial discussions with National Grid ESO about ScotWind inclusion in the HND and delivery queues. Further information about ScotWind inclusion in the HND and ESO thinking can be found on the related ESO press release on 11 February 2022.
[38] The documents from the ESO's Offshore Coordination Project Phase 1 are available at Project documents | National Grid ESO
[39] FES 2020 documents | National Grid ESO

5.3. The Cost Benefit Analysis (CBA) element[40] of the ESO's Offshore Coordination Phase 1 work considers two different approaches to offshore transmission network design to connect the offshore wind generation included in the Leading the Way scenario between 2025 and 2050:

- **Counterfactual approach:** this approach applies the existing design process. Therefore, the results from modelling this approach can be applied to the counterfactual.

- **Integrated approach:** this approach is similar to the holistic development model which we consider to be representative of the Pathway to 2030 design process.

5.4. The CBA report notes several assumptions made in applying these approaches, including the assumption that either approach could be applied to offshore wind projects connecting from 2025 onwards.

5.5. The CBA estimates the integrated approach to save 19% on capex and 14% on opex, compared with the report's counterfactual approach. This IA treats these figures as illustrative indications for the size of the market that could be suitable for delivery through the delivery model options or counterfactual scenarios.

Table 5 Lifetime comparison of the discounted costs of the Counterfactual approach and the Integrated approach (Phase 1 Report) (values in £m)

Approach to offshore transmission network design	Counterfactual approach (similar to the IA counterfactual)	Integrated approach (similar to deliver models 1-7)	Savings %
capex £m	29,000	23,399	19%
opex £m	7,113	6,097	14%
Total	**36,112**	**29,496**	**18%**

Set up costs

5.6. We do not estimate there to be a substantial additional set up cost following our delivery model decision compared with the counterfactual scenario. This is because

[40] Cost-Benefit Analysis of Offshore Transmission Network Designs available at [download (nationalgrideso.com)]

we do not expect to establish a new team. Instead, we expect the existing OFTO team to tender these assets.

Competition transaction costs

5.7. Transaction costs relate to costs that a developer has incurred during, and as a consequence, of the tender process.[41] Bidders will incur costs when preparing bids, for example when undertaking due diligence. The preferred bidder will also need to engage in the processes required ahead of taking over the project (such as further due diligence). These costs are reviewed at the Final Transfer Value stage of the cost assessment process and include:

- tender fees payable to Ofgem; and
- the developer's internal and external costs as a result of the tender process.

5.8. For context, successful bidder costs from OFTO Tender Round 1, 2 and 3 ranged from approximately 1-3% of the Final Transfer Value of the assets.[42]

5.9. It is possible that transaction costs could increase if coordinated assets are more complex. We do not expect these to be material given the overall costs involved.

5.10. We would mitigate the risk of a cancelled tender by ensuring the commercial and regulatory terms are appropriate and acceptable to the market before the tender commences. As the procurement body, we would have oversight of the overall governance of the process (for example, to determine whether there have been any material changes).

Range of cost savings or increases for different competition scenarios

5.11. Based on internal assessments and analysis, 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. We estimated costs to increase by 10-15% with no competition (Option 1), costs to decrease by 5-10% with

[41] Offshore Transmission: Guidance for Cost Assessment (2022)
[42] Extending competition in electricity transmission: impact assessment (ofgem.gov.uk) (p.15)

late competition (Options 3 and 7) and costs to decrease by 10-15% with early competition (Options 4 and 5), when compared with the very late competition model.

5.12. We recognise the risk that the capex cost saving estimates for the different competition scenarios could vary between projects. We think that the providing a five percent range for all three scenarios helps us cover the potential range.

Timescale for development of new policy framework

5.13. We estimated the development of new regulations based on slow (24 months) and fast (16 months) policy development scenarios for the Workstream. We assumed that all delivery model options would require 16-24 months' work prior to implementing a tender process. The assumption stems partially from changes which take a fixed amount of time, such as changing tender regulations.

Timescale for competition processes to take place

5.14. In our policy assessment analysis, we assumed that running a competition process would take between 18-24 months across all of the delivery models where competition is applied.

5.15. We do not expect that substantive changes to the tender process will be required, with the same tendering steps being in place. This is because of the similarities between the factual and counterfactual scenarios. However, we might need to extend some of the timescales associated with specific steps of the tendering process to ensure the bidders have time to carry out due diligence on more complex non-radial coordinated projects.

5.16. The generator commissioning clause (GCC) in the Electricity Act allows developers to own and operate offshore transmission infrastructure for up to 18 months after it has become available for the transmission of power, without the need for a transmission licence.

5.17. This was raised as an issue for coordinated projects delivering in multiple stages where the commissioning of subsequent projects occurs beyond the 18 months allowed by the clause, creating uncertainty about assets and any potential sale to an OFTO. There can be a disconnect between the GCC period and the OFTO divestment timescale, including the competitive tendering process. BEIS is exploring options to address this problem to provide developers with confidence about the legal standing of their assets. BEIS is considering how it will apply this clause in the context of non-radial offshore transmission.[43]

Timescale for delivery of offshore Transmission Assets

5.18. We assumed that the assets would be delivered at the same speed irrespective of the entity which would deliver them. We estimated the delivery 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, TOs, or developers.

5.19. We also assumed that there would be at least six months of commercial negotiations between developers if one of the developer competition models was adopted. We recognised that some negotiation would likely be required between parties to manage risk but considered that, at least in the case of Leasing Round 4 projects, the ongoing option fees were likely to incentivise speedy negotiation.

Timescale for changes to the industry codes and standards

5.20. Our minded-to delivery model decision is likely to lead to multiple and significant changes to industry codes and standards. Depending on the scope and scale of any changes these could require significant time. We continue to work with National Grid Electricity System Operator to establish those changes that might be necessary and the appropriate timescales in which they need to be delivered. We expect changes to be delivered through the normal code governance process.

5.21. We note that there are significant outstanding questions as to the current transmission network use of system ("TNUoS") charging regime's applicability to the different connection configurations which might be delivered under Pathway to 2030, and more broadly under the OTNR programme. We consider that, given the close links between the treatment of the various offshore models and our broader review of transmission charging, we and industry will need to consider whether further changes are required in this area. Whilst we do not envisage our TNUoS Task Forces containing a specific OTNR-related workstream, we think it will be important that both programmes of work

[43] Offshore Transmission Network Review: update on early opportunities (publishing.service.gov.uk)

recognise their mutual effects and approach charging questions in a consistent manner. The ToRs for the TNUoS Task Forces will consider locational TNUoS charges (Wider and Local Charges) in general, and aim for onshore and offshore consistency where it is appropriate.

Potential for delay

5.22. We compared the Earliest In Service Dates (EISD) of each competition model (No competition, early competition, late competition and very late competition).

5.23. The EISD optimistic to pessimistic range is based on a number of assumptions. The optimistic view assumes at-risk activity by industry, policy development and tendering requiring 36 months, consenting taking 24 months and construction 36 months. The pessimistic view assumes no at-risk activity by industry, policy development and tendering requiring 48 months, consenting taking 24 months and construction 60 months. The estimated timescales are based on internal assessments and analysis. This means that where competition is on the critical path for delivery of infrastructure, it is less likely that the 2030 targets will be achieved. For the purposes of our analysis, we consider the projects being developed with uniform EISDs. In practice, we recognise that the projects will be delivered with a range of EISDs.

5.24. We estimated that a very late competition model is likely to deliver the 2030 targets. We estimated a delay of one to two years to be possible for a late competition model, while we expected a probable three-to-four-year delay for the early competition models.

5.25. In our view, the implementation of any of the competition models referenced in this IA could be implemented in a manner that ensures the running of competitive tenders does not in and of itself lead to delays in the delivery of key infrastructure. However, this assumes that the competitive processes have already been developed. In the context of this workstream we do not have tender processes for early or late competition which we can implement. We have therefore had to account for the fact that developing and implementing a tender would likely cause a hiatus in the development of necessary offshore transmission infrastructure.

5.26. Our minded-to decision does not set a precedent for the Enduring Regime's selection of delivery model(s) for the delivery of offshore transmission infrastructure. Key policy decisions underpinning any future Enduring Regime would be recommended by BEIS with Ofgem playing a key role in delivery, alongside OTNR partner organisations, in line with its remit. We expect a Government Response document to last year's Enduring Regime consultation to be published in due course.[44]

[44] Offshore Transmission Network Review: Enduring Regime and Multi-Purpose Interconnectors (publishing.service.gov.uk)

6. Monetised costs and benefits

Section summary

This section considers the cost of potential delay, in terms of both option fees and carbon, compared with the potential capex costs or savings of the different competition models.

Cost of delay in option fees

6.1. Both ScotWind and Leasing Round 4 offshore wind projects pay an option fee. ScotWind projects pay a single fee when they enter an option to lease – this secures the option for ten years. In contrast, Leasing Round 4 projects pay an annual fee from the time they enter an option to lease until they begin construction. This means each year of delay increases the cost that may be passed through to the consumer in the cost of energy – each year of delay could result in ~£879m, or £668m if discounted, being paid by developers in aggregate to the Treasury. Although we cannot be certain about developers' commercial strategies and thus 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.

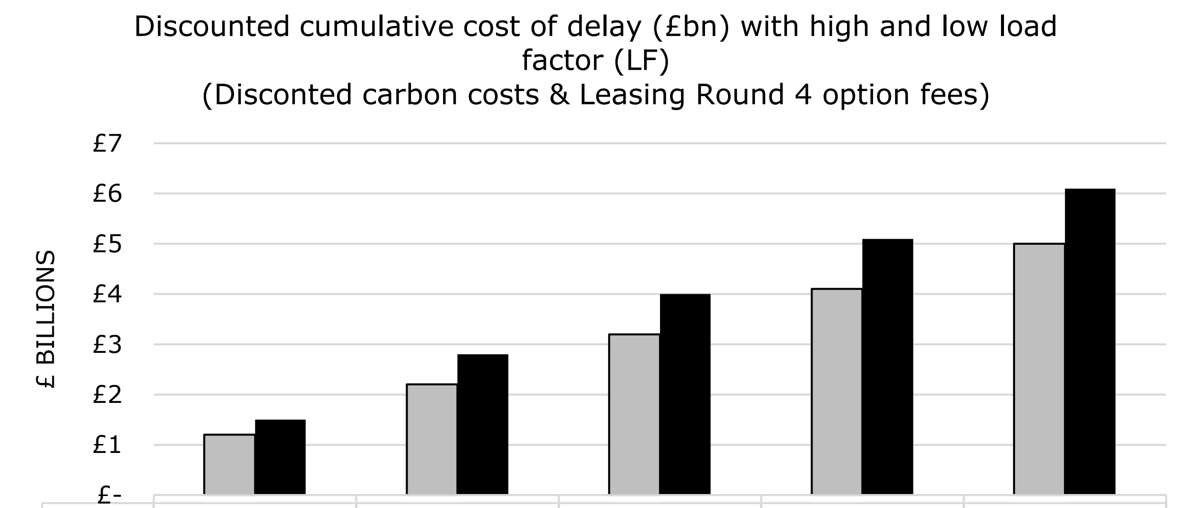
Cost of delay in carbon

6.2. The second area of cost is delay in decreasing the amount of generation reliant on fossil fuels. 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.[45] We estimate that a one year delay (from 2030 to 2031) in exporting power from the Leasing Round 4 and the first tranche of ScotWind projects could be worth £0.7bn-£1.1bn, or £0.5-0.8bn if discounted.[46] This is calculated by assuming that each MWh of new offshore generation would displace generation at the average grid carbon intensity, based on BEIS Emissions Factors and projected Carbon Pricing values.[47] We use the average because

[45] Valuation of greenhouse gas emissions: for policy appraisal and evaluation - GOV.UK (www.gov.uk)
[46] First tranche of ScotWind refers to the ESO's decision that the HND will facilitate connection of a further 10.7 GW in Scotland. Inclusion of ScotWind in the Holistic Network Design - National Grid ESO
[47] Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal

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 a low and high load factor estimates.[48] These are discounted, marginal abatement values which used central carbon values.

Table 6: discounted cumulative costs of delay with high and low load factor (LF) (Carbon costs and leasing round 4 Option fees)



Low LF	£1.2	£2.2	£3.2	£4.1	£5.0
High LF	£1.5	£2.8	£4.0	£5.1	£6.1

Cost of delay vs competition savings

6.3. Based on internal assessments and analysis, 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. We estimated costs to increase by 10-15% with no competition (Model 1), costs to decrease by 5-10% with late competition (Models 3 and 7) and costs to decrease by 10-15% with early competition (Models 4 and 5), when compared with the very late competition model.

6.4. Table 7 below illustrates our comparative analysis results. The table displays the discounted delay costs for carbon and option fees in cumulative terms, for the 19GW

[48] 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).

included in the HND. These discounted delay costs are calculated for both low and high load factors. The carbon costs are discounted for each year and the option fees are discounted for the asset life period of 25 years. The delay costs are compared with the potential capex costs. The capex costs are based on the three different competition scenarios when compared with the very late competition model. In the "No Delay 2030" column one can see what we estimated the discounted savings or cost increases to be for each scenario.

6.5. In Table 7, the double lined ranges display the estimated EISD for each competition scenario. We estimated no delay for the no competition model as we would not have to design or run a tender exercise. For the late competition scenario, we estimated a possible one-to-two-year delay, which is based on us designing and running a tender exercise for the coordinated, OFTO build assets. For the early competition scenarios, we estimated a probable three-to-four-year delay based on us designing and running a tender process, as well as producing a detailed design to be tendered, which would cause a hiatus period.

6.6. Table 7 uses shading from light green to dark red to demonstrate total cost savings turning into cost increases when cumulative discounted delays are compared with capex costs. These are for each low and high load factor and competition scenario.

6.7. Table 7 displays how the discounted cost of delay outweighs the potential capex savings being brought on by competition. We estimated the costly delays avoided by the very late competition model outweigh the potential capex savings provided by the other competition models. We further discuss in section 8 why we selected the generator led very late competition model over the TO led very late competition model.

Table 7 - Cost of delay vs capex savings (£ per million)	**2030 no delay applied**	**2031**	**2032**	**2033**	**2034**	**2035**
Discounted option fees and carbon costs (cumulative, low load factor, 19GW, with discounted option fee)****	**Very late competition base line**	**1,166****	**2,231****	**3,209****	**4,126****	**4,981****
Discounted option fees and carbon costs (cumulative, high load factor, 19GW, with discounted option fee)****	**Very late competition base line**	**1,464****	**2,781****	**3,975****	**5,083****	**6,106****
No competition, TO build + 10% cost increase (discounted) with cumulative discounted delay, low load factor	**1,135***	2,263	3,291	4,233	5,115	5,937
No competition, TO build + 15% cost increase (discounted) with cumulative discounted delay, low load factor	**1,703***	2,811	3,821	4,745	5,610	6,415
No competition, TO build + 10% cost increase (discounted) with cumulative discounted delay, high load factor	**1,135***	2,561	3,841	4,999	6,073	7,062
No competition, TO build + 15% cost increase (discounted) with cumulative discounted delay, high load factor	**1,703***	3,110	4,371	5,511	6,568	7,540
Late competition - 5% cost decrease (discounted) with cumulative discounted delay, low load factor	**-568**	617*	1,701*	2,697	3,631	4,503
Late competition - 10% cost decrease (discounted) with cumulative discounted delay, low load factor	**-1,135**	69*	1,171*	2,185	3,136	4,025
Late competition - 5% cost decrease (discounted) with cumulative discounted delay, high load factor	**-568**	915*	2,251*	3,463	4,589	5,628
Late competition - 10% cost decrease (discounted) with cumulative discounted delay, high load factor	**-1,135**	367*	1,721*	2,951	4,094	5,150
Early competition - 10% cost decrease (discounted) with cumulative discounted delay, low load factor	**-1,135**	69	1,171	2,185*	3,136*	4,025
Early competition - 15% cost decrease (discounted) with cumulative discounted delay, low load factor	**-1,703**	-480***	641	1,673*	2,641*	3,547
Early competition - 10% cost decrease (discounted) with cumulative discounted delay, high load factor	**-1,135**	367	1,721	2,951*	4,094*	5,150
Early competition - 15% cost decrease (discounted) with cumulative discounted delay, high load factor	**-1,703**	-182***	1,191	2,439*	3,599*	4,672

* Double brackets represent estimated Earliest In Service Dates for each competition scenario. We estimated no delay for the no competition model as we would not have to design or run a tender exercise. For the late competition scenario, we estimated a possible one-to-two-year delay, which is based on us designing and running a tender exercise for the coordinated, OFTO build assets. For the early competition scenarios, we estimated a

probable three-to-four-year delay based on us designing and running a tender process, as well as producing a detailed design to be tendered, which would cause a hiatus period.
** These are the combined cumulative discounted carbon and option fees costs of a delay beyond 2030. Based on LR4 projects' annual options fees, and emissions not abated as a result of delaying LR4 and first ScotWind tranche projects based on BEIS projected emission and low and high load factors.
*** We recognise that the estimated one year of delay costs do not outweigh the estimated early competition (-15%) cost savings. We want to note that this would be an unlikely outcome considering the likely delays to the delivery schedule being caused by the tender process development, design production and tender running.
**** Our analysis is based on ~19GW being delivered through the HND. This includes the Leasing Round 4 (7.98GW) and first ~11GW of ScotWind. The ScotWind figure was reached based on initial discussions with National Grid ESO about ScotWind inclusion in the HND and delivery queues. Further information about ScotWind inclusion in the HND and ESO thinking can be found on the related ESO press release on 11 February 2022.

7. Non-monetised costs and benefits

Section summary

This section focuses on the importance of competition and the effects of the decision.

The use of competitive tendering in delivery

7.1. Competitive tendering has benefits in a range of areas. It is difficult to quantify all the impacts of opening markets up to competition. Increasing innovation and introducing new products, services and technologies are possible benefits of competitive tendering but these benefits are dynamic and hard to measure. We have a duty to apply competition where it can deliver benefits to consumers, whether that be in terms of cost or time savings. The benefits could also be in terms of introducing innovation or cost discovery.

7.2. The type of benefit that can be achieved by competition varies depending on the type of competition being used. Our July 2021 consultation further considers the various benefits of different competition scenarios.[49]

- Early competition could allow for a greater level innovation spanning from the design to the operational phases, which could reduce associated costs.
- Late competition focuses on the construction and operational phases which could lead to reduced capex and opex costs.
- Very late competition has the benefit of insulating the OFTO from construction risks. This can attract low cost of capital for the operational phase.

Increasing energy security by reducing risk of delay

7.3. Reducing the risks of delays to the 2030 targets, can in turn reduce GB dependence on power sources exposed to volatile international prices we cannot control.[50] Recent

[49] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[50] Major acceleration of homegrown power in Britain's plan for greater energy independence - GOV.UK (www.gov.uk)

events support our minded to decision, these include the spike in global energy prices, provoked by surging demand after the pandemic as well as Russia's invasion of Ukraine. Selecting the most suitable delivery model to deliver the ambitious 2030 targets, as well as help reduce GB reliance on expensive fossil fuels. Fossil fuels are subject to volatile gas prices set by international markets we are unable to control. Boosting our diverse sources of homegrown energy can increase energy security in the long-term.[51]

[51] British energy security strategy - GOV.UK (www.gov.uk)

8. Options analysis

Section summary

The section considers why the early competition, no-competition and late competition models were discounted as options. We also consider how the generators were determined to be the most suitable party to carry out the very late competition delivery model option.

Policy assessment used when analysing delivery model options

8.1. Throughout this section, when discussing the delivery model options, we refer to both our duties and the OTNR Policy Assessment Criteria. Policy Assessment Criteria that can be used across OTNR workstreams and organisations have been agreed through the OTNR Governance processes. These 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.

8.2. The Policy Assessment Criteria has 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 Revolution[52] 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, we are using the criteria to shape policy options and evaluate options but we will be steered by our statutory duties to make decisions that are in the best interests of consumers. The full text of the Policy Assessment Criteria are included in Annex 1 of this document.

8.3. Our 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.[53] The interests of such consumers are their interests taken as

[52] The Ten Point Plan for a Green Industrial Revolution (publishing.service.gov.uk)

[53] Our powers and duties | Ofgem

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

Excluding early competition model options

Table 8 Early competition models

Delivery model option	Holistic network design	Detailed network design	Pre-Construction (eg consenting)	Construction	Operation
4. Early OFTO competition	ESO	ESO or TO	OFTO	OFTO	OFTO
5. Very early OFTO competition	ESO	OFTO	OFTO	OFTO	OFTO

8.4. 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.[54] Models entailing a competition prior to the development of the Detailed Network Design (DND) would require additional time for us to develop (up to 24 months) and then implement (a further 18 months) a tender process. This would interrupt project development with a potential hiatus of up to 36 months.

8.5. 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 the tender process. This would not happen in an early competition model. This means that early competition models may put at risk delivery of the 40GW offshore wind target by 2030. For the early competition model, we estimated a probable three-to-four-year delay. This, therefore, ruled out models four and five as included in our consultation.

8.6. In Section 6, we compared the potential capex savings or cost increases between the very late competition model and its alternatives. The alternatives considered were: no competition, late competition and early competition.

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

8.7. We estimated the early competition models to provide capex savings of 10-15% or £1.5-2.2bn when compared with a potential very late competition model for the ~£15bn worth of assets as part of the 2030 targets. The estimate falls to £1.1-1.7bn when discounted. We estimated the development and implementation of an early competition model to cause a probable three-to-four-year delay. The delay costs, in terms of carbon and additional annual option fees, range between £4.5-5.6bn for three years of delay and £5.9-7.3bn for four years of delay. These figures fall to £3.2-4.0bn for three years of delay and £4.1-5.1bn for four years if discounted.

8.8. We determined that the estimated delay and its cost outweigh the potential capex cost savings associated with the early competition models.

Excluding the no competition model option

Table 9 TO build and operate model

Delivery model option	Holistic network design	Detailed network design	Pre-Construction (eg consenting)	Construction	Operation
1. TO build and operate	ESO	TO	TO	TO	TO

8.9. 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.[55]

8.10. There would likely also be an additional cost under model 1 as there would be no competition. We have used the savings observed under the current OFTO regime as a proxy for calculating those additional costs. We estimated a cost increase of 10-15% or £1.5-2.2bn or £1.1-1.7bn if discounted. This model has a negative impact on competition. This is counter to the policy assessment criteria (2b, Renewable generation competition impact, Appendix 1) and our primary duties. One of Ofgem's principal objectives is to protect the interests of existing and future consumers in relation to gas conveyed through pipes and electricity conveyed by distribution or

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

transmission systems.[56] We make rules that allow competition to be introduced into the electricity and gas systems where appropriate and ensure that competition works in the interests of consumers over time.

8.11. Although we estimate a delay to the 2030 targets to be less likely in the no competition scenario, when compared with the early or late competition models, the risk of delay is possible. We want to avoid combined cost increases resulting from delayed projects and the no competition scenario.

Excluding the late competition - OFTO build model options

Table 10 OFTO build models

Delivery model option	Holistic network design	Detailed network design	Pre-Construction (eg consenting)	Construction	Operation
3. TO design > OFTO build and operate	ESO	TO	TO	OFTO	OFTO
7. Developer design > OFTO build and operate	ESO	Offshore generator	Offshore generator	OFTO	OFTO

8.12. Taking in to account the Government's 2030 goals and using the OTNR policy assessment criteria we determined late competition to be unsuitable for this workstream.

8.13. We recognised that implementing a late competition model would present challenges in meeting the following criteria: deliverability (1a), decarbonisation (1b), deployment impact (2a) and risk allocation (2d).[57] For the deliverability (1a) late competition could run a risk of delaying developments due to increased tendering process development

[56] Our powers and duties | Ofgem

[57] Criteria section 1a, Deliverability, "Policy can be delivered in a timely and proportional fashion for the workstream".
Criteria section 1b, Decarbonisation, is described as: "Supports decarbonisation/NZ agenda ie total/speed of emissions reduction".
Criteria section 2a "It speeds up deployment of offshore wind compared to an uncoordinated solution".
Criteria section 2d "Places risks on those best placed to manage them".

timescales. We estimated a delay of one to two years to be possible for a late competition model, while we expected a probable three-to-four-year delay for the early competition models. The delivery timeline assumptions are further explained in section 5.

8.14. Under any of the delivery models available the delivery body, whether it is OFTO, TO, or developer, this delivery body is likely to face challenges. These are summarised below.

- TOs have limited experience of delivering infrastructure in an offshore environment, and no experience delivering offshore transmission specifically. In contrast the TO's systems are far more complex than those offshore transmission systems that have to date been constructed by developers and operated by OFTOs in GB.
- OFTOs have significant experience of owning and operating offshore transmission assets. However, as of yet they have not constructed an offshore transmission system in GB. However, a number of potential and current OFTOs have experience of delivering in other jurisdictions.
- Developers have significant experience of delivering radial offshore transmission systems. However, they have no experience of delivering more complex meshed or integrated systems.

8.15. Both generators and OFTOs have a number of incentives to deliver in a timely fashion. However, not all incentives are equal. Seabed lease option payments incentivise generators to commence construction. This is more relevant for the generators who hold agreements with the Crown Estate (England and Wales). These generators pay annual option fees, instead of the Scottish set amount option fees paid to the Crown Estate Scotland.

8.16. Should generators be awarded a CfD, they will face the non-delivery disincentive. Under the CfD, generators must demonstrate delivery progress by the "milestone delivery date" being a maximum of 18 months after contract signature. Delivery progress can be demonstrated by providing evidence either of (i) spend of 10% of total pre-commissioning costs, or (ii) project commitments. Failure to meet this milestone may result in termination of the CfD contract. Generators may face late delivery penalties under their commercial contracts.

8.17. The different potential delivery bodies have different incentives. These may be natural, eg the ability to receive revenues from the sale of power and/or services. These could also be of a regulatory or contractual nature, ie an agreement to provide a connection in the case of an OFTO or TO. Whilst it may be difficult to replicate the 'natural' incentives of developers on regulated network companies – we have a range of tools we can apply. The specific incentives applicable to different delivery bodies have not specifically informed our minded to decision. Our decision has largely been driven by the desire to facilitate Government's targets.

8.18. As mentioned previously in section 6, we recognise that potential capex savings are possible in the late OFTO build models, but due to estimated delays, they would be outweighed by the abated carbon and option fee costs. The capex savings could range between £0.7-1.5bn (£0.6-1.1bn discounted), while a year's delay to 2031 could cost between £1.6-2.0bn (£1.2-1.5bn discounted), and the cumulative cost of two years being £3.1-3.9bn (£2.2-2.8bn discounted). We estimated a delay of one to two years to be possible for a late competition model. The capex and delay costs are explained further in section 6. As such, we determined that implementing a late competition, OFTO build model would risk higher carbon delay costs and slowdown offshore wind deployment. Additionally, the model could place risk on OFTOs which might not be best placed to manage them, due to their lack of GB offshore wind construction experience.

Excluding the very late competition model, TO build model option

Table 11 TO build, OFTO operate model

Delivery model option	Holistic network design	Detailed network design	Pre-Construction (eg consenting)	Construction	Operation
2. TO build > OFTO operate	ESO	TO	TO	TO	OFTO

8.19. Under a very late competition model, we needed to decide which party is responsible for the detailed design and construction of the offshore transmission assets before these are transferred to the successful OFTO following a tender exercise. On balance, we consider that offshore generators are better placed to carry out this work than incumbent TOs.

8.20. Consultation responses 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 built.[58]

8.21. While TOs can draw on experience from their own networks, this is less directly relevant because it is primarily onshore experience. To date, the TOs have not undertaken design or consenting for offshore transmission assets that connect wind generators to the onshore grid. However, elements of their experience in other areas are relevant for the DND and pre-construction phase activities. TOs have experience with assets physically located offshore, with complex network designs, and with supply chain engagement.

8.22. TOs may struggle to ramp-up their organisational capacity in order to construct such a significant portfolio of assets within the required timeframes, given the scale and scope of their other business activities. This concern was supported by a number of consultation responses.[59]

8.23. In contrast, offshore generators have experience in building offshore transmission assets and in general have a strong natural incentive (given the disincentive of the option fee and the incentive of revenues from power sales) to deliver on time.

8.24. There is some evidence that the developers would be willing to coordinate, based on stakeholder engagement and offshore developers bringing forward proposals for coordinated solutions.

8.25. We believe that the commercial incentives on offshore generators will incentivise them to work together efficiently. These incentives include seabed lease option payments, non-delivery incentive under Contracts for Difference (CfD) and potential late delivery penalties. In addition, the changes to the treatment of AI discussed under Early Opportunities reduces a significant barrier to the offshore generators' use of AI.[60]

[58] 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
[59] July 2021 consultation responses: Mainstream Renewable Power, p. 8; Elia Group, p.5.
[60] Consultation on our Minded-to Decision on Anticipatory Investment and Implementing Policy Changes (ofgem.gov.uk)

9. Preferred option

Section summary

This section highlights why the generator led very late competition model was chosen as the preferred option to deliver the Pathway to 2030 workstream's ambitious goals for offshore wind generation.

Table 12 Preferred option – very late competition Generator Build

Delivery model option	Holistic network design	Detailed network design	Pre-Construction (eg consenting)	Construction	Operation
6. Developer design and build > OFTO operate	ESO	Offshore generator	Offshore generator	Offshore generator	OFTO

9.1. Our minded-to decision is to adopt a 'very late competition Generator Build' model for Pathway to 2030, to facilitate the delivery of Leasing Round 4 (LR4) and the first tranche of ScotWind projects.[61] On balance, we think this is the best option to deliver the offshore transmission infrastructure required to achieve government's offshore wind generation targets on time and at a reasonable cost.

9.2. This is an evolution of the model that has been used since 2009, via the existing OFTO regime, and would include some adaptations to reflect that the coordinated offshore transmission infrastructure would be more complex than a single (radial) link from an offshore windfarm to another generating station or substation.

[61] First tranche of ScotWind referes to the ESO's decision that the HND will facilitate connection of a further 10.7 GW in Scotland. Inclusion of ScotWind in the Holistic Network Design - National Grid ESO

Estimated cost of delay outweighs the potential savings from running tender earlier in infrastructure development

9.3. In addition to the project specific impact of delay to delivery of offshore generation, there are also potential wider energy system costs of delay. The cost of delay includes option fees paid by the LR4 projects and the delay in decreasing the amount of generation reliant on fossil fuels. We estimated the very late competition Generator Build model to be least likely to suffer from delays thereby minimising the risk of incurring delay costs.

9.4. We reached our minded to decision by taking in to account the savings that could be achieved through different competition models, timely delivery of the necessary infrastructure required by 2030 thereby facilitating government's offshore wind targets by 2030.

9.5. We estimated a one-to-two-year delay to be possible for a late competition model while a three-to-four-year delay could be probable for an early competition model. This is because we would need time to develop and implement a tender process.

9.6. We estimated the cumulative cost of delay beyond the 2030 target, based on carbon cost estimates and additional annual LR4 option fee payments. The range is caused by the low and high load factor estimates. The cumulative cost of delay ranged between £1.6bn-£2.0bn for one year and £3.1bn-3.9bn for two years (£1.2-1.5bn and £2.2-2.8bn if discounted). The estimate for three to four years ranged between £4.5bn-£5.6bn and £5.9-£7.3bn (£3.2-4.0 and £4.1-5.1bn discounted) respectively. These costs outweighed the potential capex cost savings stemming from the late competition or early competition models.

9.7. We also 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.[62] We would expect implementation of our minded-to decision to continue to provide savings (relative to TO delivery) in a similar fashion alongside promoting competition in the markets.

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

Developers' incentives

9.8. Developers face strong incentives to complete the DND and pre-construction phase as quickly as possible, to avoid delays in connecting their project. Similarly, generators are more strongly incentivised to develop a cost efficient DND, as the ongoing cost of the project affects their TNUoS charges. The commercial negotiations and indemnifications that can arise from the existing OFTO transfer process create incentives for the generator to deliver a quality asset. This would apply to both radial and coordinated transmission assets. The generator is incentivised to ensure construction is delivered to a high standard.

9.9. Offshore generators have experience in building offshore transmission assets and in general have a strong natural incentive to deliver on time – as the transmission infrastructure is their route to market.

9.10. Generators also have strong inherent incentives 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.

Developers' capability

9.11. Generation developers have significant experience in solving the specific challenges in design and consenting of offshore wind connections – albeit for radial solutions. While TOs can draw on experience from their own more complex networks, this is less directly relevant because it is primarily onshore experience.

9.12. Generators have historically been responsible for the development of offshore transmission assets in GB. This has given them significant experience asset delivery. Access to financing is considered broadly comparable across TOs and generators.

Developers' coordination efforts

9.13. There is anecdotal evidence that the developers would be willing to coordinated based on stakeholder engagement. In addition, offshore developers have brought forward proposals for coordinated solutions, in the Early Opportunities workstream.

9.14. As mentioned above, we would expect the commercial negotiations and indemnifications that can arise from the existing OFTO transfer process, to create incentives for the generator to deliver a quality asset. This should apply to coordinated non-radial assets.

Appendix 1 Policy Assessment Criteria

- 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 ESO for 'integrated' and 'status quo' models will be used to support options assessments where appropriate. Please refer to the ESO 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 CATO 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. • Anticipatory Investment 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 generation project or projects.

Authority

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

B

BEIS

Department for Business, Energy & Industrial Strategy

C

CBA

Cost benefit analysis

CDG

Central design group, formed by ESO and the TOs to support the production of the HND within the scope of the Pathway to 2030 workstream. Central design group formed by the ESO and the TOs to support the production of the HND within the scope of the Pathway to 2030 workstream.

CES

Crown Estate Scotland

CfD

Contract for Difference

CUSC

Connection and Use of System Code

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.

E

Electricity Act

The Electricity Act 1989 as amended from time to time.

ESO

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.

GFAI

Generator focussed anticipatory investment

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 Pathway to 2030 workstream.

I

Interconnector Cost Assessment Guidance

Guidance document that sets out the processes that we follow whilst undertaking the cost assessments of electricity interconnectors.

Interconnector Licence

A licence authorising a person to participate in the operation of an electricity interconnector.

ITPR

Integrated Transmission Planning and Regulation

N

NETS

National Electricity Transmission System

NOA

Network Options Assessment

O

O&M

Operation and maintenance

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.

T

TCE

The Crown Estate

Tender Regulations

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

Tender Revenue Stream (TRS)

The payment an OFTO receives over its revenue term.

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 Pathway to 2030 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.