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Impact Assessment

Initial impact assessment on allocating anticipatory investment risk in offshore transmission systems in Early Opportunities

Division:	Networks	**Type of measure:**	Commercial network regulation
Team:	Offshore Coordination	**Type of IA:**	Qualified under Section 5A UA 2000
Associated documents:	Consultation on our Minded-to Decision	**Contact for enquiries:**	Offshore.Coordination@ofgem.gov.uk
Coverage:	Full		

Summary: Intervention and Options

We assess the likely impact of three policy options to reform the treatment of anticipatory investment (AI) by developers in offshore transmission assets to support the connection of specific future offshore wind projects. The objectives are to facilitate greater coordination between relatively mature development projects in accordance with the aims of the Early Opportunities workstream of the OTNR, while managing and mitigating any allocation of AI risk to consumers. The options differ in respect of which party or parties face the transmission use of system charges for the AI element of shared offshore transmission assets before the future project connects. Under all options, the risk that the future project fails to connect is allocated to consumers, subject to our proposed risk management and mitigation measures.

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

The objective of the Early Opportunities workstream of the Offshore Transmission Network Review (OTNR) is to facilitate greater coordination in the connection of offshore wind projects which are at a relatively advanced stage of development. Following industry engagement and public consultation, we have identified that the biggest barrier to achieving this objective is the risk involved for developers in making anticipatory investment (AI) to support the later connection of other offshore development(s). According to developers, this risk is manifested in the cost assessment process that we follow to determine the transfer value for offshore electricity transmission assets, in which a project that has made AI may not be able to recover that AI at the point of asset transfer to an Offshore Transmission Owner (OFTO). Ofgem intervention is necessary to address this barrier to greater coordination. In the consultation on our minded-to decision, we have set out that economic and efficient AI made by a developer for the connection of another known development should be included in the final transfer value paid by the OFTO. This impact assessment considers policy options in respect of which parties should face the AI-related element of the transmission network use of system charges for those OFTO assets. Amendments to the Use of System Charging Methodology and the User Commitment Methodology would be required to give effect to our change in policy in relation to AI.

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

We have considered the objective of the Early Opportunities workstream of the OTNR and the OTNR policy assessment criteria to develop policy options for treating AI which is intended to support the later connection of other offshore development(s).[1] For example, criterion 2b relates to maintaining an effective competitive regime and level playing field for different actors in renewable generation.[2] The criteria provide a common way of considering options within an OTNR workstream, subject to resourcing proportionality and consistency with relevant public bodies' strategic aims and statutory duties. In that respect,

[1] Our consultation on our minded-to decision explains our process to develop the policy options which are considered in this impact assessment.
[2] The criteria were included in Appendix 3 of consultation in July 2021 [Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem]

in assessing and selecting options, we have been steered by our principal objective to protect the interests of existing and future consumers where 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. [3] For example, we have sought to manage and mitigate any additional allocation of AI risk to consumers.

What are the policy options that have been considered, including any alternatives to regulation? Please justify the preferred option (further details in Evidence Base)

Three policy options have been considered. The options differ in respect of which parties face the TNUoS charges to recover the cost of offshore transmission assets incorporating AI. The options distinguish between the AI cost to be recovered for the period prior to the potential later user connecting to the shared assets ('AI Cost Gap'), and the risk that the potential later user never uses the shared assets ('AI Risk'). The options are listed in the table below.

Policy option	AI Cost Gap	AI Risk
Policy option 1	Paid by consumers	Allocated to consumers
Policy option 2	Paid by initial user and later user	Allocated to consumers
Policy option 3	Paid by later user	Allocated to consumers

Our minded-to decision is for AI Risk and AI Cost Gap to be allocated in accordance with policy option 3. Under this option, the risk that the potential later user never uses the shared assets is allocated to consumers. This allocation is intended to support the objectives of the OTNR and facilitate increased coordination in this workstream. It would result in a cost to consumers if the risk materialises. Also under option 3, the AI cost to be recovered for the period prior to the potential later user connecting to the shared assets is faced by the later user through their TNUoS charges over the relevant OFTO licence period. The corresponding charges for the later user would reflect the cost of the offshore infrastructure assets that they can or do use, based on the extent to which they can use them, and they would incentivise the later user to connect as quickly as possible.

[3] Our powers and duties | Ofgem

Preferred option - Monetised Impacts (£m)

Business Impact Target Qualifying Provision	Non-qualifying
Business Impact Target (EANDCB)[4]	Not relevant
Net Benefit to GB Consumer	See below
Wider Benefits/Costs for Society	

Our analysis is based on the estimated benefits of two generic offshore generators sharing an offshore transmission system. These benefits are indicative of the benefits that we expect to be achieved through coordination in the Early Opportunities workstream. To assess the impact of policy options to allocate AI cost and AI risk, we consider the case where AI in the offshore transmission system is required due to the two generator projects being developed and constructed on different timescales. The policy options differ in respect of which party or parties face the AI cost gap and AI risk. The quantitative impact of the policy options is assessed in terms of estimated capital cost savings and administrative costs, relative to the counterfactual of the two offshore generators being connected through separate offshore transmission links. We also consider how the policy options may affect the likelihood and distributional impact of the risk materialising that the later user of the shared assets fails to connect and use the shared assets. Our analysis indicates that our minded-to decision (policy option 3) is likely to result in the greatest consumer net benefit as well as the allocation of the AI cost gap to the party best placed to manage it. In the example considered, policy option 3 would result in an indicative net benefit to consumers of £14.6 million if the later user connects and uses the shared assets (this figure excludes potential additional benefits that may flow from generators to consumers through any reduction in CfD allocation round clearing price due to other capital cost savings). If the potential later user fails to connect and use the assets, with no recovery of user commitment amounts from the potential later user, the modelled net cost to consumers in this example is £138 million. We are proposing to implement an early stage assessment process manage this risk to consumers and proposing the extension of user commitment arrangements to mitigate the cost to consumers if the risk materialises.

[4] Equivalent Annual Net Direct Cost to Business

Preferred option - Hard to Monetise Impacts

The non-monetisable impacts arising from offshore coordination relate to the environmental and social impacts compared to the counterfactual of separate connections for the same generation projects. These benefits are project specific. For instance, the impact in environmentally sensitive areas would have a higher value. In the context of this workstream, where the opportunities for coordination are variable and limited in number, measuring the average impact of a single project or a group of projects would be subject to significant uncertainty. We conclude in section 5 that consumers are likely to benefit from reduced environmental and social impacts to a similar extent under the three policy options.

Key Assumptions/sensitivities/risks

We estimate the potential impacts of the policy options in the context of two notional offshore generators sharing an offshore transmission system. We believe that these projects are representative of those that could come forward through the Early Opportunities workstream of the Offshore Transmission Network Review. We do not consider it is possible to assess the impacts at a portfolio level because within this workstream, the decision to pursue greater coordination is at the discretion of the relevant project developer(s). This means that the number and nature of projects that will pursue greater coordination is uncertain. We expect that in each instance where projects choose to pursue greater coordination, all the developers would be involved in the proposition of the shared assets and accept the resulting interdependencies such as those relating to the transmission charges that the respective projects will face.

Will the policy be reviewed? No[5]	**If applicable, set review date:**

Is this proposal in scope of the Public Sector Equality Duty?	**Yes[6]**

[5] The policy would affect a limited number of in-flight projects and will be supplemented by policy changes through other OTNR workstreams.
[6] We do not consider that the policy options assessed in this IA would have an adverse equality impact on individuals with protected characteristics.

Summary table for all options

	AI cost for period prior to later user using shared assets	AI risk that later user never uses shared assets	Main effects on consumer outcomes	Considerations
Policy option 1	Paid by consumers	Allocated to consumers	If both users connect: lowest net benefit for consumers If future user fails to connect: higher cost to consumers	We consider policy option 3 is likely to allocate the AI cost to the party best placed to manage it. Under all policy options, we consider the risk allocation to consumers is necessary to realise the capital cost, environmental and social benefits of coordination for consumers.
Policy option 2	Paid by initial user and later user	Allocated to consumers	If both users connect: higher net benefit for consumers If future user fails to connect: lowest cost to consumers	
Policy option 3	Paid by later user	Allocated to consumers	If both users connect: higher net benefit for consumers If future user fails to connect: higher cost to consumers	

Contents

1. Problem under consideration

Section summary

The problem under consideration is the management of the risk for offshore wind developers of making anticipatory investment (AI) in offshore transmission infrastructure to support the later connection of other offshore development(s). Through our engagement with industry, we have identified this problem as the biggest barrier to greater coordination for projects in the Early Opportunities workstream of the Offshore Transmission Network Review (OTNR). This impact assessment considers policy options to address this barrier and facilitate AI to deliver beneficial coordination, while managing and mitigating any additional allocation of risk to consumers. In this section, we set out how the existing regimes for offshore transmission and interconnection treat AI, and the aim of the OTNR to change the existing regimes to find an appropriate balance between environmental, social, and economic costs in support of the UK's offshore wind deployment targets. We explain that our assessment of options will reflect our principal objective to protect the interests of existing and future consumers.

Existing arrangements

Treatment of anticipatory investment costs in the offshore transmission regime

1.1. The current framework for connecting offshore wind projects to the onshore network enables the developer of each project to manage the development and delivery of their own connection.[7] This approach has resulted in each project to date being connected via a separate, point-to-point offshore transmission connection.

[7] Developers may choose to either develop and construct the transmission assets themselves and then transfer the assets to the appointed OFTO (the Generator Build option) or undertake high-level design and preliminary works, beyond which point the detailed design, procurement, delivery, and operation of the assets would be undertaken by the appointed OFTO (the OFTO Build option). Since the regime was launched in 2009, no offshore wind developer has selected the OFTO Build option.

1.2. Competitive tender processes are used to select and licence Offshore Transmission Owners (OFTOs) to own and operate offshore transmission assets. To facilitate the tender process, we calculate the economic and efficient costs which ought to be, or ought to have been, incurred in connection with the development and construction of the assets.[8] This cost assessment process determines the transfer value before the assets are purchased from the developer by the appointed OFTO. Until we determine the final transfer value, any costs incurred by a developer of offshore transmission assets are 'at risk'.

1.3. We recognise the potential for offshore wind projects to develop coordinated offshore transmission infrastructure with the capability to:[9]

- support the later connection of specific offshore generation projects. We refer to this type of investment by an offshore wind developer as Generator Focussed Anticipatory Investment (GFAI); and
- provide wider network benefits. We refer to this type of investment by an offshore wind developer as Developer-led Wider Network Benefit Investment (WNBI). Our approach to Developer-led WNBI is beyond the scope of this impact assessment.

1.4. Where GFAI is undertaken by a developer to support the later connection of specific offshore wind project(s) being progressed by that same developer, we only allow costs within the transfer value that are directly applicable to the initial offshore wind project subject to the tender exercise. The AI risk remains with the developer.

1.5. Where GFAI is undertaken by a developer to support the later connection of specific offshore wind project(s) being progressed by a different developer, we have said we would review how the developer undertaking the GFAI should be remunerated on a case-by-case basis. Therefore there is currently a lack of certainty on the treatment of AI where one developer incurs costs on behalf of another developer.

1.6. In our consultation on our minded-to decision, we explain our minded-to decision to remove the distinction between single developer GFAI and GFAI by a developer for other developer(s). In addition, in our consultation and this IA, we refer to 'AI' rather than 'GFAI'

[8] Offshore Transmission: Guidance for Cost Assessment | Ofgem
[9] Paragraphs 3.60-3.65, Offshore Transmission: Guidance for Cost Assessment | Ofgem

to reflect the other potential drivers of AI in the Early Opportunities workstream in addition to generator focussed AI.

Treatment of anticipatory investment costs in the interconnector regime

1.7. Electricity interconnectors require an Electricity Interconnector Licence and are either subject to the cap and floor regime or operate under an exemption.[10]

1.8. The cap and floor levels set a minimum return and maximum return that interconnector developers can earn. We undertake a cost assessment process to ensure that only economic and efficient costs, associated with the development, construction, and operation of an interconnector project, contribute to the project's cap and floor levels.[11] There is currently a lack of certainty on the treatment of AI in the cap and floor regime.

Offshore transmission charging arrangements

1.9. After the relevant offshore transmission assets have been transferred to the ownership of the appointed OFTO, the offshore generator becomes liable for transmission network use of system (TNUoS) charges.[12] These include local offshore charges (comprising offshore local circuit and offshore local substation charges) in respect of the OFTO assets used by the generator, and wider charges in respect of the shared infrastructure in the zone into which the generator connects onshore. Offshore generators do not pay local onshore substation charges, unless the OFTO connection to the Main Interconnected Transmission System is via a distribution network circuit.[13]

1.10. The local offshore charges are calculated based on the OFTO's revenue, the capital cost and rating (in MW/MVA) of each relevant OFTO asset, the security factor of the offshore local circuit, and the generator's Transmission Entry Capacity (TEC).[14]

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[10] Interconnectors | Ofgem
[11] Electricity Interconnectors Cost Assessment Guidance Document | Ofgem
[12] Section 14 of the Connection and Use of System Code (CUSC) sets out the statement of the use of system methodology and the statement of the connection charging methodology CUSC Code Documents | National Grid ESO
[13] The Main Interconnected Transmission System (MITS) is defined in the Security and Quality of Supply Standard (SQSS) SQSS Code Documents | National Grid ESO
[14] For further guidance, see TNUoS Offshore Guidance.pdf (nationalgrideso.com)

1.11. If a relevant OFTO asset has a rating greater than the generator's TEC, then the cost of that unused capacity is socialised through the transmission demand residual charge. In practice, the level of unused capacity is minimised by our cost assessment process which allows the offshore wind developer to recover only the economic and efficient costs which ought to be, or ought to have been, incurred in connection with the development and construction of assets that are directly applicable to the specific offshore wind project subject to the tender exercise.

1.12. In February 2022, we published our next steps and summary of responses received following a Call for Evidence on TNUoS charges.[15] We said that in the context of on- and offshore network developments, our work on Future System Operator, and the emerging localised flexibility markets, there is a longer-term question as to the function of TNUoS in a less centralised, more flexible energy system.

Offshore transmission user commitment arrangements

1.13. When a generator applies to connect to the transmission system or to increase its TEC, Transmission Owners (TOs) undertake the required network investment to accommodate its needs. However, the generator may decide to cancel its project or reduce its TEC. This can potentially result in unnecessary costs for wider network users and ultimately for consumers.

1.14. User commitment places liabilities on users to financially secure the cost of works or ensure that otherwise avoidable costs are not incurred. Enduring user commitment arrangements for generation users were introduced as Section 15 of the CUSC and went live from April 2013.[16] During the period from signature of a connection agreement to commissioning, generation users secure a proportion of their liability depending on factors such as the achievement of project milestones and the expected completion date.

1.15. Under the Generator Build option for offshore transmission assets, there is no requirement in CUSC Section 15 for user commitment in respect of Offshore Transmission System Development User Works (OTSDUW), as the generator would effectively be

[15] TNUoS Next Steps 250222 (ofgem.gov.uk)
[16] CUSC Code Documents | National Grid ESO

indemnifying itself.[17] Under the OFTO Build option, the generator is liable for and secures OFTO works. Under the Generator Build option and OFTO Build option, the generator is liable for and secures any onshore TO works required.

The Contracts for Difference scheme

1.16. The Electricity Market Reform programme introduced two mechanisms: the Capacity Market, to provide incentives for investment in the overall level of reliable capacity needed to ensure secure electricity supplies; and Contracts for Difference (CfDs), to support new investment in low-carbon electricity generation.[18]

1.17. Renewable generators that meet the eligibility requirements can bid for CfDs in competitive CfD allocation rounds. The bid requirements include a strike price (£/MWh).

1.18. When the market price for electricity generated by a CfD generator is below the strike price set out in the contract, payments are made to the CfD generator to make up the difference. The obligation to make payments to CfD generators under CfDs is funded by electricity suppliers, and therefore by consumers. When the market price is above the strike price, the CfD generator pays back the difference.

1.19. The CfD auction is held on a pay-as-clear basis, subject to no project receiving a higher strike price than its technology-specific Administrative Strike Price.[19] All the lowest bids up to a maximum budget and/or capacity are accepted and awarded a 15-year CfD at the clearing price, ie the bid strike price of the most expensive successful project.

Rationale for intervention

Offshore Transmission Network Review

[17] OTSDUW are defined in the Grid Code as those activities and/or works for the design, planning, consenting and/or construction and installation of the Offshore Transmission System to be undertaken by the User as identified in Part 2 of Appendix I of the relevant Construction Agreement. [Grid Code documents | National Grid ESO]
[18] [Electricity Market Reform: Contracts for Difference - GOV.UK (www.gov.uk)]
[19] Administrative Strike Prices are set by BEIS to reflect a range of factors, including technology specific factors, market conditions and policy considerations.

1.20. 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.

1.21. 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. 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.

1.22. The Electricity System Operator's Offshore Coordination Phase 1 report demonstrated that increased coordination in the connection of all offshore projects, from 2025 onwards or 2030 onwards, has the potential to deliver consumer savings as well as environmental and social benefits.[20]

1.23. We published our consultation on changes intended to bring about greater coordination in the development of offshore energy networks in July 2021.[21] In January 2022, we published a summary of the responses we received, as well as further detail on the next steps for each workstream prior to decisions and further consultation.[22]

Early Opportunities workstream

1.24. The Early Opportunities workstream of the OTNR is seeking to enable developers to pursue greater coordination and thereby realise the benefits of coordination. The intent is to achieve this by leveraging flexibility within the existing regulatory framework or by making near-term changes to it. Within this workstream, the decision to pursue greater coordination is at the discretion of the relevant developer(s), rather than mandatory.

1.25. In August 2020, the Department for Business, Energy & Industrial Strategy (BEIS) and Ofgem issued a joint Open Letter in which we called for stakeholder views to support

[20] Offshore Coordination Project - project documents | National Grid ESO
[21] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[22] Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

the OTNR.[23] Since issuing the Open Letter, we have received 16 proposals for early opportunities for coordination across most of the major developers.[24]

1.26. The workstream is focussed on the connections of offshore wind projects which are at a relatively advanced stage of development. These projects are likely to have undertaken a significant amount of design and development work.

1.27. The development of an offshore wind project can take up to around ten years, and policy and regulatory changes could have unintended consequences for these projects including delay, increased cost, and additional risk. We do not want to slow the rate of development.

1.28. The existing framework for offshore wind development incorporates competition between developers, including seabed leasing rounds and CfD allocation rounds. This framework has successfully driven cost reductions and timely delivery. However, it disincentivises offshore wind developers from taking on additional development risks which may put them at a competitive disadvantage, such as AI in offshore transmission infrastructure to support the later connection of other offshore development(s).

1.29. In paragraphs 1.4-1.5, we explained that where AI is undertaken by a developer to support the later connection of specific offshore wind project(s), the AI risk is either allocated to the developer making the AI or allocated on a case-by-case basis. Through industry engagement and public consultation,[25] we have identified that the management of AI risk is the biggest barrier to greater coordination for projects in the Early Opportunities workstream. Regulatory intervention is intended to address this barrier, enabling developers to undertake AI to deliver beneficial coordination while managing and mitigating any additional allocation of AI risk to consumers.

1.30. In our previous publications and our consultation on our minded-to decision, we have also identified other barriers to greater coordination.[26] These include the requirement

[23] Increasing the level of coordination in offshore electricity infrastructure (publishing.service.gov.uk)
[24] BEIS provided further information in the OTNR webinar January 2022 presentation Offshore Transmission Network Review: December 2021 Webinar (publishing.service.gov.uk)
[25] See paragraph 1.20 for links to previous publications
[26] Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem

for changes to the industry codes and standards, the relevant licences, and the Tender Regulations. These potential changes are beyond the scope of this impact assessment.

Policy objectives

1.31. In this impact assessment, we assess the likely impact of three policy options to reform the treatment of AI by developers in offshore transmission assets, in the context of the Early Opportunities workstream of the OTNR. This workstream is seeking to enable developers to pursue greater beneficial coordination in offshore transmission infrastructure in the near term to connect relatively mature offshore wind development projects.

1.32. The OTNR project partners have agreed a set of Policy Assessment Criteria that can be used across the OTNR workstreams.[27] The nine criteria reflect the aim of the OTNR 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 criteria fall under four main areas: deliverability of OTNR policy and Net Zero, economics and commercials, environmental and societal impact, and consumer and system impact.

1.33. We have used the criteria to develop policy options to manage the risk of making AI in offshore transmission infrastructure for projects in the Early Opportunities workstream.[28]

1.34. The criteria provide a common way of considering options within a workstream, subject to resourcing proportionality and consistency with relevant public bodies' strategic aims and statutory duties. In that respect, in assessing and selecting options, we have been steered by our principal objective to protect the interests of existing and future consumers where 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.[29]

[27] The criteria were included in Appendix 3 of consultation in July 2021 Consultation on changes intended to bring about greater coordination in the development of offshore energy networks | Ofgem
[28] See Section 2 of our Consultation on our Minded-to Decision on Anticipatory Investment and Implementation of Policy Changes
[29] Our powers and duties | Ofgem

2. Approach

Section summary

We explain that we have assessed the concept of a shared offshore transmission system to identify the impact of different policy options for managing AI risk in Early Opportunities. The assessment includes quantitative analysis, which considers the potential cost impacts on consumers and the relevant offshore generators under three policy options and across multiple scenarios. In this section, we also discuss the main assumptions used in the analysis, which relate to areas including the proposed early stage assessment process for AI, the relative development timeframes for the projects proposing the AI, and the applicable transmission use of system charging arrangements.

Assumptions used in this analysis

Defining the counterfactual

2.1. This impact assessment considers the policy options relative to the counterfactual. Under the latter, it is assumed that the same generation projects are developed with separate, point-to-point offshore transmission connections.

Early stage assessment process

2.2. In our consultation on our minded-to decision, we have set out that projects proposing to undertake AI will be subject to an early stage assessment process that will verify the timing and scope of the projects and associated offshore transmission assets, as well as the expected benefits of the proposed AI. We expect that the early stage assessment process will occur sufficiently early in the project development lifecycle for the shared infrastructure to be reflected in the project development activities.

2.3. We also expect that in each instance where projects choose to pursue greater coordination, all the developers in that instance would be involved in the proposition of the shared assets and accept the resulting interdependencies such as those relating to the projects' planning consents and the transmission charges that the respective projects will face.

Development timeframes

2.4. For the purposes of this workstream, we consider AI to be expenditure in offshore transmission infrastructure to support the later connection of a specific known offshore development or developments.[30] Therefore, we assume that the projects that will use the coordinated infrastructure are developed within similar timeframes.

2.5. Given the annual frequency of CfD allocation rounds,[31] we assume that the initial user is awarded a CfD and subsequently begins operation 1-2 years ahead of the potential later user's scheduled operational date. This assumption is factored into the modelling used to produce the results shown in Table 4, Table 5 and Table 6 in section 4 of this IA.

Charging arrangements

2.6. In February 2022, we published our next steps and summary of responses received following a Call for Evidence on TNUoS charges.[32] One of the potential areas for reform, highlighted in our October 2021 Call for Evidence, is the arrangements for "Offshore connections in the context of our joint Ofgem/BEIS Offshore Transmission Network Review".[33]

2.7. In addition, as of January 2022, there is a legal review proceeding in relation to aspects of the transmission charging arrangements.[34] This relates to the treatment of local assets accessed by a later user with respect to calculating compliance with the Limiting Regulation.

2.8. Our analysis herein is based on current transmission charging arrangements (consistent with the ESO's latest TNUoS Tariffs forecast statement).[35] This assumes that all Local Charges for Local Circuits and Local Substations paid by generators shall fall under

[30] See Section 1 of our Consultation on our Minded-to Decision on Anticipatory Investment and Implementation of Policy Changes
[31] Government hits accelerator on low-cost renewable power - GOV.UK (www.gov.uk)
[32] TNUoS Next Steps 250222 (ofgem.gov.uk)
[33] TNUoS Reform - a Call for Evidence | Ofgem
[34] NGESO (2022) Final TNUoS Tariffs for 2022/23
[35] NGESO (2022) Final TNUoS Tariffs for 2022/23

the Connection Exclusion for the purposes of assessing compliance with the €0-2.50/MWh range.

Other assumptions

2.9. In our consultation on our minded-to decision, we have set out that economic and efficient AI for the connection of another known development should be included in the final transfer value of the relevant offshore transmission assets at the end of the relevant tender process. We have made this assumption in this impact assessment. This treatment of AI during the cost assessment process will be subject to the developer successfully progressing through the early stage assessment process discussed in paragraph 2.2.

2.10. We expect that the developer responsible for constructing the AI (initial user) is incentivised to provide economic and efficient delivery through the cost assessment process.

2.11. In our consultation on our minded-to decision, we have also set out our view that user commitment principles should be extended to AI delivered through the generator-build model in Early Opportunities, to protect consumers' interests from the risk of stranded assets. Correspondingly, in paragraphs 4.44-4.45 we consider the potential impact if the later user faces a level of user commitment liabilities during the period from signature of a connection agreement to commissioning.

2.12. Since the existing regime was launched in 2009, no offshore wind developer has selected the OFTO Build option. For the purposes of this impact assessment, we assume that the Generator Build option will continue to be chosen by developers.

2.13. We assume that all generators involved in the development of AI will participate in CfD allocation rounds, and that they will bid in a cost-reflective manner. In other words, this impact assessment does not assess bidder behaviour in the context of AI policy.

Uncertainties

Assessing the policy impact on a limited set of developer-led opportunities

2.14. Within the Early Opportunities workstream, the decision to pursue greater coordination is at the discretion of the relevant project developer(s), rather than mandatory (see paragraph 1.24). This means that the number of projects that will pursue greater coordination due to the regulatory changes in this workstream is uncertain, although it is likely to be limited by the focus on this workstream on the connections of offshore wind projects which are at a relatively advanced stage of development. The nature of the coordination opportunities that developers may choose to pursue is also uncertain. These factors mean that it is difficult to assess the impact of any policy holistically.

2.15. To address this uncertainty in this impact assessment, we consider the shared offshore transmission system concept. This is one of the six coordination concepts which we identified in our consultation in July 2021, following engagement with developers on the coordination opportunities which they were pursuing.[36] We consider that the shared offshore transmission system concept is the most relevant to the management of AI in the context of this workstream. For some of the other coordination concepts, we anticipate that AI risk would be managed through the existing price control arrangements, charging methodology and user commitment methodology where applicable.

Quantitative analysis

2.16. This impact assessment is supported by quantitative analysis presented in section 4. There are two main parts of this analysis, which are discussed in the following subsections. Firstly, we commissioned a report to provide estimated capital expenditure (capex) values for the offshore transmission infrastructure required to connect two notional offshore wind generators. Secondly, we used those values to estimate the potential impacts on consumers and generators under the three policy options.

Capex estimates for offshore transmission infrastructure

2.17. We commissioned a report from DNV to provide estimated capital expenditure (capex) values for the offshore transmission infrastructure required to connect two generic offshore wind generators in two scenarios: **Counterfactual**, based on separate connection assets, and **Coordinated**, based on shared connection assets. In the coordinated scenario, the initial user developers and installs assets that would also be used by the potential later

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

user. This investment by the initial user represents AI. The report is provided in Appendix 2.

2.18. In both scenarios, the report is based on the use of high voltage alternating current (HVAC) connection assets as the most likely approach, given the generator designs (discussed below). The cost data presented in the report is from DNV's database of public data relating to transmission equipment used in offshore wind and interconnector projects in the North Sea. The cost figures include the cost of equipment supply, installation and transportation, civil works, project management, property rights, risk contingency and profit margin. The figures are inflation-adjusted to 2021.

2.19. Two generator designs are considered in the report: **Design 1** and **Design 2**, which are summarised in Table 1. We believe these designs are broadly representative of the offshore wind projects which may seek to develop coordinated infrastructure within the scope of the Early Opportunities workstream of the OTNR. Consideration of two generator designs has indicated how this variable may affect capex reductions between counterfactual and coordinated scenarios, as well as the level of upfront investment required in the shared assets.

Table 1 Generic offshore wind farm design specifications (see Appendix 2)

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

2.20. In the quantitative analysis, we consider Design 2 only. We consider that this approach is more conservative because with Design 2 the capex reductions between counterfactual and coordinated are lower than Design 1, in absolute and relative terms.

Estimated cost impacts under the three policy options

2.21. We used the estimated capital expenditure (capex) values presented in Appendix 2 to estimate the cost impacts on consumers and generators under the three policy options for the case of Design 2.

2.22. The analysis is illustrative and has been undertaken to identify how the policy options affect the distribution and quantum of potential cost impacts. It is a stylised approach, relying on high-level assumptions on certain implementation details that are beyond the scope of this impact assessment. For example, the methodology to determine the AI and non-AI elements of shared asset costs, and the methodology to determine user commitment liabilities and securities, would be subject to code modifications raised through CUSC governance arrangements.[37]

2.23. We take the following approach in the analysis:

2.23.1. The initial investment in the shared assets is separated into AI and non-AI elements, based on the anticipated proportional usage of the overall shared infrastructure according to the generators' respective Transmission Entry Capacities. This calculation is indicative and, as explained in 2.22, in practice the methodology to determine the AI and non-AI elements would be subject to code modification through the existing governance processes.

2.23.2. Based on the AI element of the initial investment, the AI cost gap and the quantum of potential AI risk are calculated. The concepts of AI Cost Gap and AI Risk are discussed in 3.6-3.10.

2.23.3. We consider the net impact on consumers and the generators under the three policy options in the coordinated scenario, relative to the counterfactual scenario. The counterfactual represents what is expected to be the case if there is no change to AI policy for Early Opportunities projects.

2.23.4. These policy options are "stress tested" through applying a worst-case scenario in which the potential later user fails to connect and use the shared

[37] See Section 2 of our Consultation on our Minded-to Decision on Anticipatory Investment and Implementation of Policy Changes

assets, with that failure only becoming apparent after the full initial investment has been made by the initial user. User commitment arrangements are then applied to this worst-case scenario to identify the extent of their mitigating impact. The arrangements are assumed to broadly mirror the equivalent onshore arrangements for attributable costs and assume similar project development timeframes.[38] Under the worst-case scenario, it is assumed that only the security is recovered from the later user (ie they are unable to meet the remainder of their liability). This calculation is indicative and, as explained in 2.22, in practice the methodology to determine the user commitment liabilities and securities would be subject to code modification through the existing governance processes.

2.24. The quantitative estimates presented in section 4 indicates how consumers are impacted in each scenario and under each policy option. The outputs also show the extent of generator savings relative to the counterfactual.

[38] Guidance on security arrangements and the wider user commitment arrangements set out in section 15 of the CUSC are available at https://www.nationalgrideso.com/document/188281/download

3. Policy options

Section summary

We set out the three policy options which are assessed in Section 4 and Section 5 of this impact assessment. The options relate to whether, and to what extent, the costs associated with AI in shared offshore transmission assets in Early Opportunities should be faced by consumers. The options distinguish between the AI cost to be recovered for the period prior to the potential later user connecting to shared assets, and the risk that the potential later user never uses the shared assets. This AI risk differs from the AI cost in that it is contingent, ie there is only a cost if the risk materialises. We refer to our minded-to decision that the AI cost should be faced by the later user, and the AI risk should be allocated to consumers. This corresponds to policy option 3. Finally, we discuss the concepts and definitions used in the policy options.

Summary of policy options and minded-to decision

3.1. In our consultation on our minded-to decision, we consider the allocation of AI Risk and the AI Cost Gap to four potential parties: the initial user, the later user, the OFTO and consumers. The concepts of AI Cost Gap and AI Risk are explained in paragraphs 3.6-3.10. From the combinations of potential parties, we set out three policy options. The options are shown in Table 2.

Table 2 Consolidated policy options for assessment

Policy option	AI Cost Gap	AI Risk
Policy option 1	Paid by consumers	Allocated to consumers
Policy option 2	Paid by initial user and later user	Allocated to consumers
Policy option 3	Paid by later user	Allocated to consumers

3.2. In all the policy options, the AI Risk is allocated to consumers. We did not include an option to allocate the AI Risk to the initial user because it would effectively mirror the existing arrangements. We did not include an option to allocate the AI Risk to the potential later user, because of stakeholder feedback that the potential later user would not be in a position to underwrite the AI element of shared asset costs prior to the award of a CfD and making a final investment decision. We did not include an option to allocate the AI Risk to the OFTO because of our expectation that the OFTO bidders would price this risk in to their bids at tender stage, potentially fixing this element of the OFTO revenue irrespective of whether the AI Risk materialises.

3.3. Our minded-to decision is for the AI Risk and AI Cost Gap to be allocated in accordance with policy option 3. Under this option, the risk that the potential later user never uses the shared offshore transmission assets is allocated to consumers. In addition, the AI cost to be recovered for the period prior to the later user connecting to shared assets is faced by the later user through their TNUoS charges, potentially over the relevant OFTO licence period.

3.4. The three policy options are assessed in sections 4 and 5 of this impact assessment. In the rest of this section, we discuss the concepts and definitions used in the policy options.

Concepts and definitions used in the policy options

Parties

3.5. Within the Early Opportunities workstream, we use the term 'anticipatory investment' (AI) to refer to investment in offshore transmission assets to support the later connection of specific offshore developments. In practice, this translates to the construction by a developer of an asset that will be used, either partially or fully, by a developer in future. In this context, we have used the following terms to define the policy options:

3.5.1. We refer to the developer making the investment in the shared asset as the **initial user**. We refer to the developer or developers that will use the shared asset in future as the **later user**.

3.5.2. We consider that the investment by the initial user in the shared asset comprises an **AI element** and a **non-AI element**. We anticipate that these elements would be determined on a case-by-case basis based on the proportional usage of the shared infrastructure (also see paragraph 2.23.1).

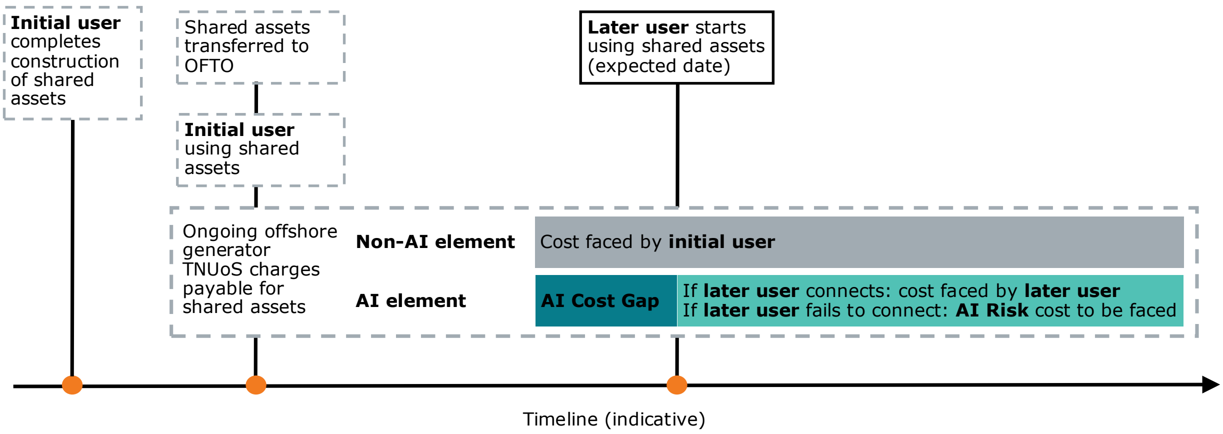
AI Cost Gap and AI Risk

3.6. Any changes in policy in relation to AI would require amendments in two areas to be given effect.

3.7. The first area is the treatment of the AI element within the OFTO and interconnector cost assessment guidance documents. As described in paragraph 2.9, we assume that economic and efficient AI for the connection of another known development will be included in the final transfer value of the relevant shared offshore transmission assets at the end of the relevant tender process. This treatment of AI during the cost assessment process will be subject to the early stage assessment process discussed in paragraph 2.2.

3.8. The second area is the recovery of the AI element through the transmission network use of system (TNUoS) charging methodology, after the relevant shared offshore transmission assets have been transferred to the appointed OFTO. Given that the OFTO transfer value will have included the economic and efficient AI, consideration of two distinct issues is required in relation to the TNUoS charging methodology: the **AI Cost Gap** and the **AI Risk**. These issues are depicted in Figure 1 and discussed in the following subsections.

Figure 1 Illustration of AI Cost Gap and AI Risk in relation to the AI element of the TNUoS charges to be recovered for the shared assets



AI Cost Gap

3.9. This issue relates to recovery of the AI element of the offshore generator TNUoS tariff in the period between the shared asset transfer to the OFTO and the point that the potential later user will start using the shared assets. Under the existing charging arrangements, the initial user would face the offshore generator TNUoS charges associated with the AI Cost Gap, as well as its own TNUoS charges.

AI Risk

3.10. This issue relates to underwriting the risk that the potential later user never uses the shared assets. This would entail paying the AI element of the offshore generator TNUoS charges for the shared assets. The AI Risk differs from the AI Cost Gap in that it is contingent, ie there is only a cost if the risk materialises. Under the existing charging arrangements, if the risk materialises then the initial user would face the resulting TNUoS charges.

4. Benefits and costs

Section summary

We discuss the potential benefits and costs from the implementation of the three policy options presented in Section 3. Firstly, we consider the overall potential benefits and costs of generators connecting through coordinated offshore transmission infrastructure rather than separate point-to-point connections. Many of the benefits are project specific. As a result, we consider potential social and environmental benefits on a qualitative basis. We consider potential capital cost savings quantitatively, with reference to the estimated costs of transmission infrastructure to connect notional offshore wind projects in coordinated and counterfactual (uncoordinated) scenarios. Secondly, we assess how the distribution of these benefits and costs may vary between the three policy options. Finally, we discuss how the policy options may affect the likelihood and distributional impact of the risk materialising that the potential later user of the coordinated infrastructure does not commission.

4.1. In this section we discuss the potential benefits and costs from the implementation of the three policy options.

4.2. We assess the potential benefits and costs of connecting two generic offshore generators through shared offshore transmission infrastructure, compared to the counterfactual of the two offshore generators being connected through separate point-to-point links. Environmental and social benefits are assessed qualitatively, whereas a quantitative approach is taken in considering administrative costs and capital cost savings.

4.3. To assess the capital cost savings, we use capital cost estimates provided by DNV in the report in Appendix 2. We introduced this report in paragraphs 2.17-2.20. As discussed in 2.20, we consider Design 2 in the quantitative assessment.

4.4. We assess how the distribution of benefits and costs versus the counterfactual may vary between the three policy options. Finally, we discuss how the policy options may affect the likelihood and distributional impact of the risk materialising that the potential later user of the coordinated assets fails to connect and use the assets. This is compared to a counterfactual in which only the initial generator is commissioned, using a dedicated connection.

Benefits of coordination

Capital cost savings

4.5. The potential for increased coordination to lead to a reduced level of capital expenditure (capex) on offshore transmission assets was demonstrated in the ESO's Offshore Coordination Phase 1 report (see paragraph 1.22).[39] This report considered the aggregated costs and benefits of a top-down integrated approach to offshore grid evolution compared to the status quo, for Great Britain in the period up to 2050.

4.6. In this impact assessment, we have considered the potential size and distribution of the benefits and costs of coordination at the level of two generic offshore generators connecting to the transmission system. This reflects the definition of the policy options in terms of allocating AI costs between the two generator projects as well as consumers. It also reflects the discrete, developer-led nature of coordination in Early Opportunities, which contrasts with the top-down integrated approach considered in the Phase 1 report.

4.7. The level of capital cost savings at a project level in a coordinated scenario compared to an uncoordinated scenario will be project specific. There may be instances in which a coordinated solution increases overall capex relative to an uncoordinated scenario but provides other benefits such as reduced environmental and social impacts or reduced development risks. For the purposes of this impact assessment, we assume that coordination opportunities in Early Opportunities will collectively result in capex savings.

4.8. This assumption is supported by the DNV report provided in Appendix 2. We introduced the report in paragraphs 2.17-2.20. The report provides estimated capex values for the offshore transmission infrastructure required to connect two generic offshore wind generators in two scenarios: Counterfactual, based on separate connection assets, and Coordinated, based on shared connection assets. Two generator designs are considered in the report: Design 1 and Design 2. The total estimated capital costs for each design, in each scenario, are shown in Table 3.

[39] Offshore Coordination Project - project documents | National Grid ESO

Table 3 Estimated total capital costs of offshore transmission assets for two generators in counterfactual and coordinated scenarios. Source: Appendix 2

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

4.9. The figures in Table 3 show that, under these designs for a shared transmission system, overall capex for a shared transmission system (coordinated) is lower than separate connections (counterfactual). These estimates demonstrate the potential materiality of the capex benefits achievable through the adoption of a policy that facilitates an increased level of coordination in offshore transmission through developer-led AI.

4.10. Coordinated projects may also result in onshore transmission network capital cost savings; these would be highly project-specific and have not been captured in the analysis in section 4.

Environmental and social benefits

4.11. The non-monetisable benefits arising from offshore coordination relate to the environmental and social impacts compared to the counterfactual of separate connections for the same generation projects. These benefits are project specific. In the context of Early Opportunities, where the opportunities for coordination are variable and limited in number, measuring the average impact of a single project or a group of projects would be subject to significant uncertainty.

4.12. The ESO's Offshore Coordination Phase 1 work includes a cost-benefit analysis (CBA) of offshore transmission network designs.[40] This CBA uses the same counterfactual as in this impact assessment (ie a separate connection for each project) but considers impacts

[40] Offshore Coordination Project - project documents | National Grid ESO

on a much broader scale. The results of the CBA can therefore provide some indication of potential environmental and social benefits of coordination.

Social

4.13. The CBA results indicate that coordinated offshore network designs could lead to beneficial impacts on natural beauty, appeal, and visual amenity, with a 60% reduction in the number of lines/cables and substations required.

4.14. The results also indicate that coordinated offshore network design could also lead to less disruption during the construction phase. However, a reduced amount of construction would also likely reduce associated benefits such as job and skills development. Local communities also expressed concerns over the long-term impact of permanent and semi-permanent large structures, as well as the adequacy of mitigation and compensation.

4.15. The value of these benefits would need to be considered on a project-specific basis, depending on the value of the local area as perceived by stakeholders and the wider population. This benefit is therefore considered on a non-monetisable basis.

Environmental

4.16. The CBA included in the ESO's Offshore Coordination Phase 1 work noted stakeholder concerns over construction resulting in negative impacts to watercourses and habitats, seabed, and marine life, as well as pollution, noise, and loss of visual charm.

4.17. The assessment concluded that coordinated solutions could lead to a 50% reduction in negative impacts through a reduction in landing points, as well as offshore and onshore cables. We note that coordinated offshore transmission assets may be larger in size compared to those in the counterfactual, which may partially offset some of these expected benefits.

4.18. A project-specific approach would be required to monetise such benefits. For instance, the impact on environmentally sensitive areas would have a higher value. This benefit is therefore considered on a non-monetisable basis.

Costs of coordination

Administrative costs

4.19. Ofgem will incur costs to implement the AI policy process and progress projects through it. The former is a one-off cost, estimated at £0.2m. Ongoing costs are estimated at £0.1m per project. Both estimates are relative to the status quo (counterfactual).

Other possible impacts of coordination

Cost of capital

4.20. If developers and any associated investors consider that the pursuit of a coordinated offshore transmission solution will change their level of risk, particularly in relation to development and construction, then this is likely to be reflected in the cost of capital for the projects involved. Risk will be assessed as a whole, constituting the net impact of multiple elements, many of which are project specific. In comparing the coordinated and counterfactual scenarios, these elements may include, but not be limited to:

- For the initial user, the increased complexity of delivering shared offshore transmission assets;
- For the later user, a reduced or removed requirement to develop offshore transmission assets;
- Interface risk with other participants; and
- Risk exposure through AI policy.

4.21. In relation to the final bullet point above, we note that the AI policy proposed in our consultation on our minded-to decision would reduce developers' AI risk exposure compared to existing AI policy. Therefore we expect our minded-to decision to support reductions in the cost of capital in this respect.

4.22. More widely, as developers and associated investors assess risk as a whole, we consider that the choice to pursue a coordinated offshore transmission solution under the Early Opportunities workstream will demonstrate that the market is willing to take and price the overall risk.

Distributional analysis

4.23. In this section, we summarise the distribution of the quantifiable benefits (the capital cost savings shown in Table 3) and costs (administrative costs) for one of the notional shared offshore transmission project designs considered by DNV in Appendix 2. The results of this analysis demonstrate how these per-project benefits and costs are likely to be distributed across consumers and generators under the three policy options, relative to the counterfactual. This provides an illustrative net impact on consumers and generators of adopting a policy that facilitates an increased level of coordination in offshore transmission through developer-led anticipatory investment, compared to the counterfactual of a separate connection for each offshore generator.

Distribution of capital cost savings

4.24. In paragraphs 4.5-4.10, we discussed the potential for increased coordination to lead to a reduced level of capital expenditure on offshore transmission assets. The distribution of these savings is subject to the transmission charging regime, through which the costs of building and maintaining transmission infrastructure are recovered. In particular, the distribution depends on whether the savings relate to (i) assets considered to be offshore local circuit or offshore local substation assets for charging purposes, or (ii) assets considered to be part of the wider network for charging purposes.[41] We consider the potential distribution of savings for each type of asset in the following subsections.

Offshore local circuit or offshore local substation assets

4.25. In paragraph 1.9, we explained that the TNUoS charges faced by an offshore generator include local offshore charges (comprising charges for offshore local circuit and offshore local substation assets), and wider charges in respect of the shared infrastructure in the zone into which the generator connects onshore.

4.26. A reduced level of capex on offshore local circuit or offshore local substation assets would reduce the level of local offshore charges faced by an offshore generator (subject to the cost assessment process we describe in paragraph 1.2). It is likely that lower local offshore charges would enable that offshore generator to bid for a CfD with a lower strike price.

4.27. We noted in paragraph 1.18 that CfD payments flow between generators and suppliers. When the market price for electricity generated by a CfD generator is below the

[41] Further information about this distinction is available in [44938-Offshore Information.pdf (nationalgrid.com)]

strike price set out in the contract, payments are made to the CfD generator to make up the difference. The obligation to make payments to CfD generators under CfDs is funded by electricity suppliers, and therefore by consumers. Therefore, a lower contract strike price is of benefit to consumers.

4.28. The CfD auction is held on a pay-as-clear basis. All the lowest bids up to a maximum budget and/or capacity are accepted and awarded a 15-year CfD at the clearing price, ie the bid strike price of the most expensive successful project. This means that capex cost savings relating to offshore local circuit or offshore local substation assets in a coordinated solution will only impact the CfD clearing price in instances where:

- the counterfactual strike price for one of the coordinating projects would have set the clearing price, and the capital cost savings result in a reduced clearing price, meaning reduced CfD payments made to all successful generators; or
- the counterfactual strike price for one of the coordinating projects would have been above the clearing price, meaning it would not have been accepted. The capital cost savings result in a reduced strike price that is below the counterfactual clearing price, resulting in a reduced clearing price, meaning reduced CfD payments made to all successful generators.

4.29. This suggests that capital cost savings relating to offshore local circuit or offshore local substation assets, which accrue to developers, do not have a certain route back to consumers through lower CfD bid prices. However, as noted in the two bullet points above, if capital savings from coordination do result in a reduced clearing price, then this benefit would manifest for every MWh produced by all successful generators, including the coordinating projects. Whilst it is possible that these potential CfD clearing price benefits to consumers will materialise, modelling them in a robust manner is not feasible. Therefore, we have not included them in Table 4, which sets out an indicative net impact of the policy options relative to the counterfactual for the case of Design 2 (as specified in Appendix 2).

Wider network assets

4.30. In considering the distribution of capital cost savings related to assets considered to be part of the wider network for charging purposes, we focus on OFTO onshore substation assets.

4.31. In paragraph 1.9, we explained that offshore generators do not pay local onshore substation charges (unless the OFTO connection to the MITS is via a distribution network circuit). In general, the costs of the OFTO onshore substation are included in the TNUoS residual tariff which is recovered from demand users.[42] Therefore any reduction in OFTO onshore substation asset capex would reduce demand charges to the benefit of consumers. We have included this as a benefit to consumers in Table 4.

4.32. Aside from OFTO onshore substations, if a coordinated offshore transmission system had the effect of reducing wider transmission network investment, then this benefit would flow through via a combination of generation and demand TNUoS charges. In such a situation, any consumer benefits would be project specific.

Distributional impact of policy options

4.33. In Table 4, we set out how the overall quantifiable benefits (capex savings) and costs (administrative costs and the AI cost gap) are likely to be distributed between consumers and generators under each of the three policy options. We do this for the case of the shared offshore transmission system described by Design 2 (as explained in paragraph 2.20).

4.34. The figures are presented relative to the counterfactual, in which both generators would have been commissioned with separate offshore transmission connections.

[42] Targeted Charging Review: Decision and Impact Assessment | Ofgem

Table 4 Net impact of policy options relative to the counterfactual, assuming that both generators are commissioned (Design 2) (£)

	Policy 1	Policy 2	Policy 3
Consumers			
Capex savings / (cost)	14,700,000	14,700,000	14,700,000
Administrative costs	- 100,000	- 100,000	- 100,000
AI cost gap	- 5,226,000	-	-
Net benefit / (cost)	**9,374,000**	**14,600,000**	**14,600,000**
Annual bill impact	**0.01**	**0.02**	**0.02**
Generators			
Capex savings / (cost)	81,500,000	81,500,000	81,500,000
Administrative costs	-	-	-
AI cost gap	5,226,000	-	-
Net benefit / (cost)	**86,726,000**	**81,500,000**	**81,500,000**

4.35. These figures are illustrative and, in practice, will be highly project dependent. However, from the results we can identify that:

4.35.1. In this instance, there is a net benefit for both consumers and generators of adopting any of the three policy options.

4.35.2. The direct benefit to consumers is related to the reduction in demand charges from the lower onshore substation capex, which is a relatively small proportion of the overall capex savings.

4.35.3. On the basis that both generators are commissioned, under policy options 2 and 3, consumers face only per-project administrative costs; generators are responsible for the payment of the AI cost gap (paid by consumers under policy option 1). Policy options 2 and 3 therefore result in the highest consumer net benefit.

4.36. Consumer benefits may be increased through aspects such as a reduction in the relevant CfD clearing price (which would represent a transfer of benefits from generators) and/or social and environmental benefits.

Interconnector capital cost savings

4.37. The coordination concepts identified in our consultation in July 2021 included the multi-purpose interconnector (OFTO-led model). Subject to the transmission charging arrangements that would apply to the interconnector element, such an arrangement may lead to capital cost savings for the interconnector.

4.38. In paragraph 1.7, we noted that interconnectors operate either under the cap and floor regime or under a fully merchant basis under an exemption.

4.39. Under a cap and floor arrangement, if the coordinated infrastructure supported lower capex by the interconnector, then the cap and floor levels determined by Ofgem would also be lower. We would expect the lower cap and floor levels to translate to benefits for consumers.[43]

4.40. Under a fully merchant model, the benefits of lower capex and the merchant risk would both be borne by the interconnector developer. The net impacts of this arrangement would depend on future wholesale electricity prices.

Assessing later user commissioning risk under the policy options

4.41. AI introduces a risk that the potential later user does not connect. This risk is underwritten by consumers in the three policy options. Table 5 illustrates how the failure of the later user to connect would impact the costs and benefits faced by consumers and generators in a 'worst case' scenario, in which the failure of the later user occurs after all capex costs have been incurred by the initial user in the case of Design 2. "AI risk" is shown in Table 5 as a cost to consumers.

4.42. In considering these costs to consumers if the later user does not connect, we note that our proposed AI policy may reduce this risk of the later user not connecting compared to the counterfactual scenario, due to planning constraints for example. In addition, the

[43] Further guidance on the cap and floor regime for electricity interconnectors is available at [Cap and Floor Regime Handbook | Ofgem]()

early stage assessment process described in paragraph 2.2 will be designed to further reduce the risk that such an event would occur.

Table 5 Net impact of policy options relative to the counterfactual, assuming the later user fails to commission (Design 2) (£)

	Policy 1	Policy 2	Policy 3
Consumers			
Capex savings / (cost)	- 7,300,000	- 7,300,000	- 7,300,000
Administrative costs	- 100,000	- 100,000	- 100,000
AI cost gap	- 5,226,000	- 2,613,000	- 5,226,000
AI risk	- 125,424,000	- 125,424,000	- 125,424,000
Net benefit / (cost)	**- 138,050,000**	**- 135,437,000**	**- 138,050,000**
Annual bill impact	**- 0.19**	**- 0.19**	**- 0.19**
Generators			
Capex savings / (cost)	32,250,000	32,250,000	32,250,000
Administrative costs	-	-	-
AI cost gap	-	- 2,613,000	-
AI risk	-	-	-
Net benefit / (cost)	**32,250,000**	**29,637,000**	**32,250,000**

4.43. As with Table 4, these figures are illustrative. However, we can identify that:

4.43.1. The realisable capex benefits, accruing to both consumers and generators, are reduced compared to those shown in Table 4, due to the non-commissioning of the later user.

4.43.2. Consumers bear the risk of the later user failing to commission; the only policy cost to generators consists of the initial user portion of the AI cost gap payment under policy option 2.

4.43.3. If the later user fails to commission, consumers must cover the AI cost gap under both policy options 1 and 3.

4.44. The extension of user commitment arrangements (described in our consultation on our minded-to decision) would reduce the consumer cost impact should the later user fail to commission. In this illustrative example of Design 2 with the later user not commissioning under the policy options or in the counterfactual, user commitment would reduce the cost to consumers in all options by £6.54m (or just under 5%), as shown in Table 6. In quantifying the "user commitment security" amounts shown in Table 6, we have assumed application of user commitment arrangements that are broadly similar to the equivalent onshore arrangements, and a 'worst case' scenario in which only the security is recovered from the later user (i.e. the remainder of the later user's liability is not recovered).

4.45. In practice, any amount recovered from the later user would depend on the applicable user commitment arrangements and the timing of cancellation by the later user.

Table 6 Net impact of policy options relative to the counterfactual where the later user fails to commission, and user commitment arrangements apply (Design 2) (£)

	Policy 1	Policy 2	Policy 3
Consumers			
Capex savings / (cost)	- 7,300,000	- 7,300,000	- 7,300,000
Administrative costs	- 100,000	- 100,000	- 100,000
AI cost gap	- 5,226,000	- 2,613,000	- 5,226,000
AI risk	- 125,424,000	- 125,424,000	- 125,424,000
User commitment security	6,540,750	6,540,750	6,540,750
Net benefit / (cost)	**- 131,509,250**	**- 128,896,250**	**- 131,509,250**
Annual bill impact	**- 0.18**	**- 0.18**	**- 0.18**
Generators			
Capex savings / (cost)	32,250,000	32,250,000	32,250,000
Administrative costs	-	-	-
AI cost gap	-	- 2,613,000	-
AI risk	-	-	-
User commitment security	- 6,540,750	- 6,540,750	- 6,540,750
Net benefit / (cost)	**25,709,250**	**23,096,250**	**25,709,250**

5. Policy option assessment

Section summary

We discuss the balance of costs and benefits under each policy option within the context of the Early Opportunities workstream. We consider that our minded-to decision (policy option 3) is likely to result in the greatest consumer net benefit as well as the allocation of the AI cost gap to the party best placed to manage it. Under policy option 3, consumers underwrite AI risk, and the later user pays the AI cost gap. In the absence of consumers underwriting the AI risk, we consider it is unlikely that increased coordination in offshore transmission infrastructure in Early Opportunities will be pursued, and therefore unlikely that the environmental, social and capex reduction benefits of coordination would be realised for consumers.

5.1. Quantifying the overall impact of the policy options in the context of the Early Opportunities workstream is challenging, given the limited pipeline of potential coordination opportunities and the variation in the associated costs and benefits. However, based on the potential benefits and costs discussed in section 4, we consider that our minded-to decision (policy option 3) is likely to result in the greatest consumer net benefit as well as the allocation of the AI cost gap to the party best placed to manage it. In this section we discuss the reasons behind this conclusion.

5.2. Policy options 2 and 3 result in a higher consumer net benefit than policy option 1 because under options 2 and 3, the AI cost gap is faced by the initial user and later user (option 2) or solely the later user (option 3). The illustrative example in Table 4 and Table 5 indicate an AI cost gap of £5.2 million: we assume that the time period between initial user and later user commissioning is relatively short. This AI cost gap is small relative to the estimated capital cost savings if both users connect (£81.5 million across the two users) and the AI risk amount of £125.4 million that would materialise as a cost if the later user does not connect.

5.3. Policy options 2 and 3 avoid consumer exposure to the initial AI cost gap, and the risk of any further cost due to delay by the later user. However, policy option 2 would expose the initial user to a proportion of this cost, potentially creating cost uncertainty for the initial user based on the delivery timeline of the later user. This uncertainty may reduce the level of competitiveness in any CfD bid made by the initial user.

5.4. Of the three parties involved (consumers, initial user, and later user), the later user has the most control over the timeline of its own commissioning. Implementing policy option 3, where the later user is responsible for the AI cost gap, would ensure the costs of the later user's delay risk is held by the party that is best able to manage that risk. It would also incentivise the later user to commission in a timely manner.

5.5. The capital cost savings to consumers shown in Table 4 and Table 5 are the same under the three policy options. They correspond to reduced capital expenditure on OFTO onshore substation assets in the coordinated scenario compared to the counterfactual scenario. Consumers are also likely to benefit from reduced environmental and social impacts to the same extent under the three policy options (see paragraphs 4.11-4.18).

5.6. Under the three policy options, the AI risk amount that would materialise if the later user failed to commission is the same, and that risk is allocated to consumers. This allocation reflects the feedback of most respondents to our July 2021 consultation, who indicated that allocating AI risk to consumers is needed to support the objectives of the OTNR and increase levels of coordination in offshore transmission assets.[44] In the absence of this risk allocation, it is unlikely that increased coordination will be pursued, and therefore unlikely that the environmental, social and capex reduction benefits of coordination would be realised for consumers.

5.7. In addition, the proposed implementation of an early stage assessment process is intended to limit the risk to consumers of inefficient or stranded AI, and the extension of user commitment arrangements would mitigate the consumer impact if the later user fails to commission. Under policy option 3, in instances where AI is made and all users of the coordinated offshore transmission infrastructure are commissioned, consumers would only face the administrative costs involved.

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

Appendix 1 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

Capex
Capital expenditure

CBA
Cost benefit analysis

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 or the Act

The Electricity Act 1989 as amended from time to time.

Electricity Interconnector Licence

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

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

I

Interconnector Cost Assessment Guidance

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

M

MITS

Main Interconnected Transmission System

O

Ofgem

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

OFTO

Offshore transmission owner

OFTO Build

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

OFTO Cost Assessment Guidance

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

OFTO Licence

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

OTNR

Offshore Transmission Network Review

T

TEC

Transmission Entry Capacity

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.

TNUoS

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

W

WNBI

Wider network benefit investment

Appendix 2 Capex estimate for offshore transmission infrastructure – report prepared by DNV

DNV

CAPEX ESTIMATE FOR OFFSHORE TRANSMISSION INFRASTRUCTURE

1 BACKGROUND AND APPROACH

This analysis focuses on understanding the difference in capital expenditure (CAPEX) between two fundamental approaches to delivering offshore transmission infrastructure. The objective is to quantify the potential difference between the total cost and the required level of the anticipatory investment.

We evaluated two offshore delivery paradigms : the "Counterfactual" and the "Coordinated" scenarios.

- The Counterfactual scenario applies the development approaches utilised to date, i.e. separate single users with dedicated radial connections.
- The Coordinated scenario applies the approach of a generic offshore transmission system shared by two users. The Initial User (IU) is assumed to develop the shared infrastructure by making an anticipatory investment (AI), i.e. investment in offshore transmission infrastructure to support the later connection of Later User (LU).

For the Coordinated scenario:

- The estimated CAPEX for the Initial User shall be provided on the basis that the Initial User contributes to the shared infrastructure.
- The estimated CAPEX for the Later User shall be provided on the basis that the Later User does not contribute to the shared infrastructure.

Two generic offshore wind farm designs shall be considered in each scenario: Design 1 and Design 2. These are shown in Table 1-1.

Table 1-1 Generic Offshore Wind Farm Design Specifications

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

Our analysis consists of the following steps:

1. Develop single-line diagrams indicating all primary equipment with its corresponding rating required to realise the proposed offshore connections.
2. Draft a bill of materials for each design based on the list of primary equipment.
3. Estimate CAPEX using the bill of materials from the previous step by applying unit cost data from DNV's database.

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Date: 23/03/2022

2 SINGLE LINE DIAGRAMS

The starting point for our analysis is the development of single-line diagrams (SLD) for the two project designs and scenarios. These single-line diagrams reflect all primary equipment and their ratings.

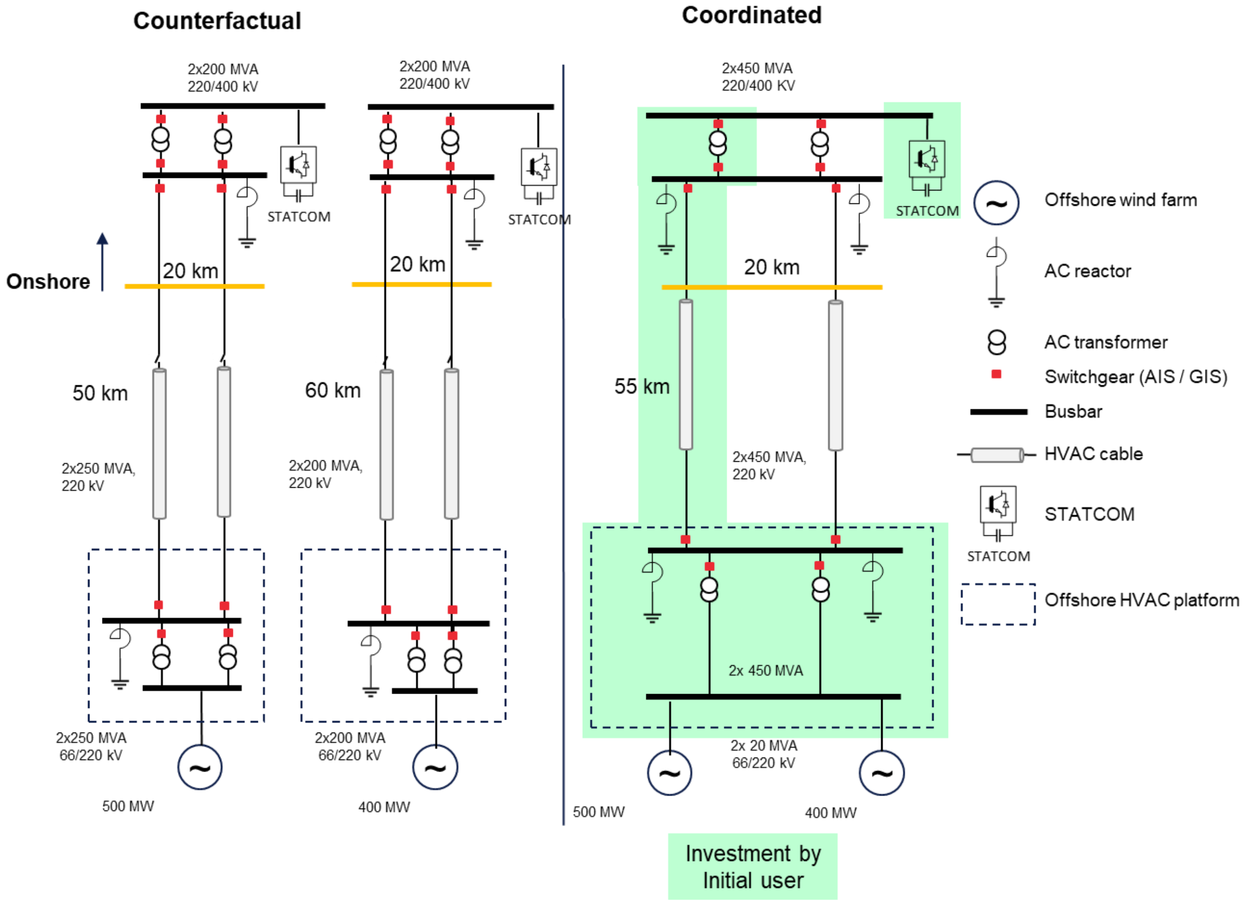

Figure 2-1 Design 1 Single-line diagram

The SLD for Design 1 is shown in Figure 2-1. In the case of the Counterfactual scenario, the two users are connected to the onshore system independently using separate radial connections, each with its own offshore and onshore substations, and the cables and transformers are configured as double circuits to maintain a sufficient level of availability. In the Coordinated scenario, the offshore and onshore platform and substations, as well as the cable systems, are shared between the two users.

To enable the Coordinated connection, the offshore platform and substation consisting of two transformers, switchgear and reactors must be built in advance. The platform cannot be structurally split, hence needs to be installed with a view to hosting the electrical infrastructure of both wind farms in the future. The offshore electrical system will come as a single package. Whilst theoretically it is possible to only install one set of transformers and leave sufficient space for the second one; in reality such arrangement tends to incur higher installation costs and makes the creation of a platform layout more challenging, which leads to a more expensive platform. We, therefore, consider this equipment to be an anticipatory investment.

In the onshore substation, only one transformer and Static Synchronous Compensator (STATCOM) need to be built in the first step since expanding the onshore substation is a normal practice and can be done by the Later User. Additionally, the Initial User will only need to deliver one HVAC cable in the first step. The second cable can be added with the connection of the second wind farm.

DNV have deliberately suggested building a 450 MVA cable in the first stage. Despite having a lower transmission capacity than required for the 500 MW wind farm, we consider the frequency and volume of curtailment that would stem from such under-dimensioning to be negligible. In contrast, the savings from the reduced number of cables (2 instead of 4 if a similar cable arrangement was applied as in the Counterfactual), and from having two similar cables, brings benefits from saving on spare parts. Furthermore, it is easier to maintain such a system because two links become interchangeable in the operational phase.

Note that the 66kV busbar is drawn as a single bus, however, in reality it is more likely to be configured as several bus sections with section couplers connecting them. The cost specific for a 66 kV system is expected to be identical for both the counterfactual and coordinated scenarios, thus is not included in this assessment.

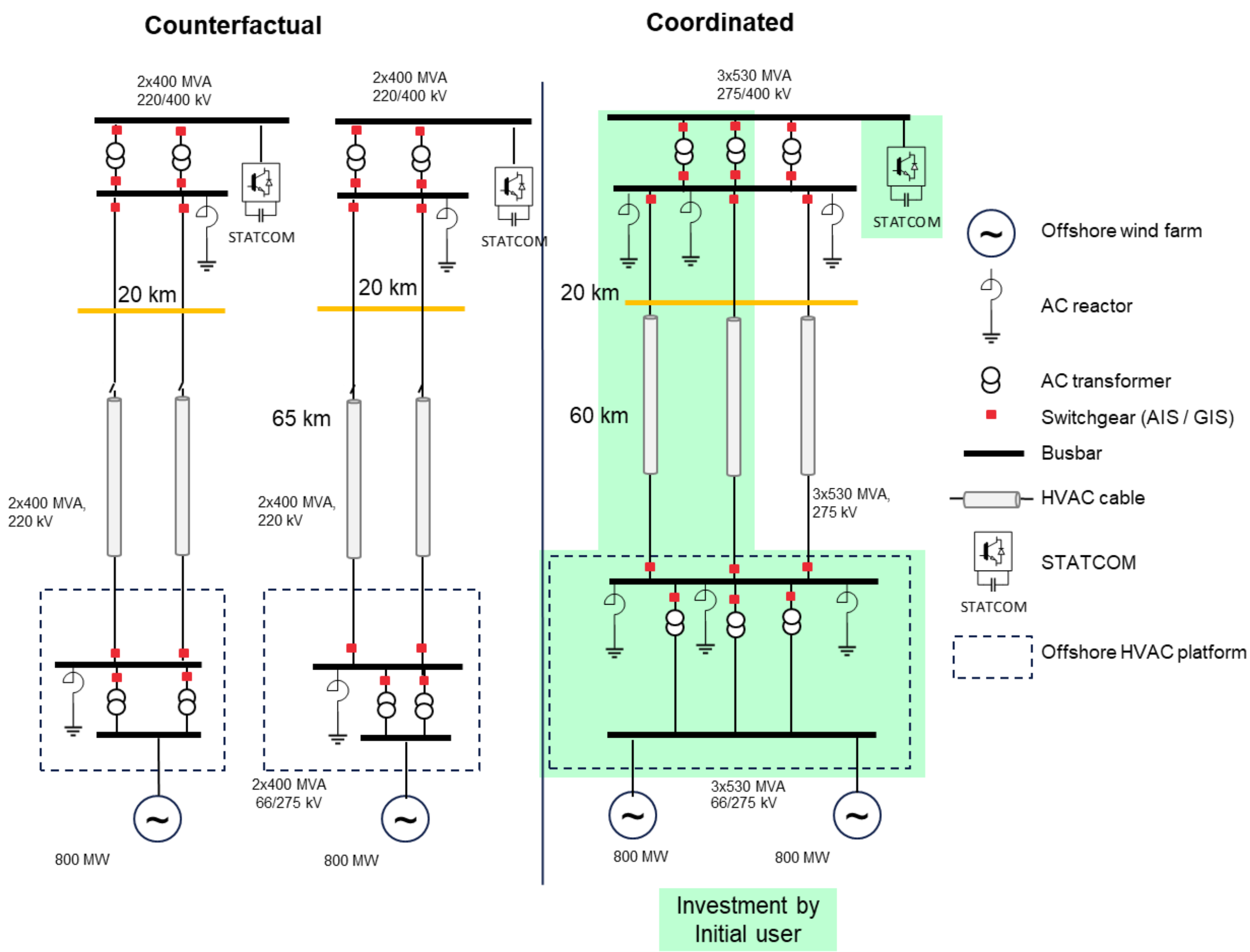

Figure 2-2 Design 2 Single-line diagram

The same considerations with regard to anticipatory investment apply for the Design 2 as for the Design 1. In the Coordinated scenario of Design 2, shown in Figure 2-2, the Initial User will initially have to deliver two cables of 1060 MVA in total to avoid curtailment at full production. Since each of the three cables is rated at 530 MVA, delivery of only one cable in stage 1 would lead to insufficient transmission capacity to deliver 800 MW to the onshore system. Similar considerations hold for the onshore transformers and reactors, where two items of each piece of equipment have to be built as an anticipatory investment. As with Design 1, the Initial User needs to build the offshore platform and the full offshore substation in the first instance to enable the Coordinated scenario.

Note that the export system is dimensioned with three parallel export cables instead of a double circuit as in Design 2. This design is due to the limited power rating achievable with a single HVAC submarine cable, which we assume to be 530 MVA at 275 kV.

3 BILL OF MATERIALS

For the transmission infrastructure, the following primary equipment is considered

- HVAC platform offshore
- HVAC transformers offshore and onshore
- HVAC reactors offshore and onshore
- HVAC cables subsea and underground
- HVAC GIS offshore
- HVAC AIS onshore
- STATCOM onshore

Table 3-1 below indicates the complete list of equipment in the Counterfactual and Coordinated scenarios for each design.

Table 3-1 Bill of Materials

Component	D1 Counterfactual		D1 Coordinated		D2 Counterfactual		D2 Coordinated	
	Rating	Number / km	Rating	Number / km	Rating	Number / km	Rating	Number / km
Offshore AC platform	500 / 400 MVA	2	900 MVA	1	800 MVA	2	1600 MVA	1
HVAC transformer offshore	250 and 200 MVA	2 and 2	450 MVA	2	400 MVA	4	530 MVA	3
HVAC GIS offshore	220kV	8	220kV	4	220kV	8	275kV	6
Reactors offshore	85 Mvar	2	60 Mvar	2	120 Mvar	4	160 Mvar	3
HVAC cable subsea	250 and 200 MVA (630 mm2 and 500 mm2)	2x 50 and 2x 60	450 MVA	2x 55	400 MVA	2x 55 and 2x 65	530 MVA	3x 60
HVAC cable underground	250 and 200 MVA	2x 20 and 2x 20	450 MVA	2x 20	400 MVA	2x 20 and 2x 20	530 MVA	3x 20
Reactors onshore	85 Mvar	2	60 Mvar	2	120 Mvar	4	160 Mvar	3
STATCOM	120 Mvar	2	200 Mvar	1	150 Mvar	2	200 Mvar	1
HVAC AIS onshore	8 of 220kV, 4 of 400kV		4 of 220kV, 2 of 400kV		8 of 220kV, 4 of 400kV		6 of 275kV, 3 of 400kV	

HVAC transformer onshore	250 and 200 MVA	2 and 2	450 MVA	2	400 MVA	4	530 MVA	3

4 CAPEX ESTIMATES

Having compiled the bill of materials, DNV estimates the following CAPEX breakdown per component type and user, as shown in Figure 4-1. Our analysis shows that for both designs, the Coordinated scenario leads to significant savings in the total CAPEX of the transmission system(s). Namely, Design 1 achieves a 30% saving from 417 to 293 million pounds, and Design 2 achieves an 18% savings from 564 to 468 million pounds. The difference in savings is caused by the rating of the wind farm and the neccesary components. The reduction is primarily driven by the decrease in the cost of the support structure and cables, both types of components being the largest contributors to the total cost. The total cost of the other component types does not vary signifcantly and is likely to be broadly similar for the Counterfactual and Coordinated scenarios regardless of the considered design.

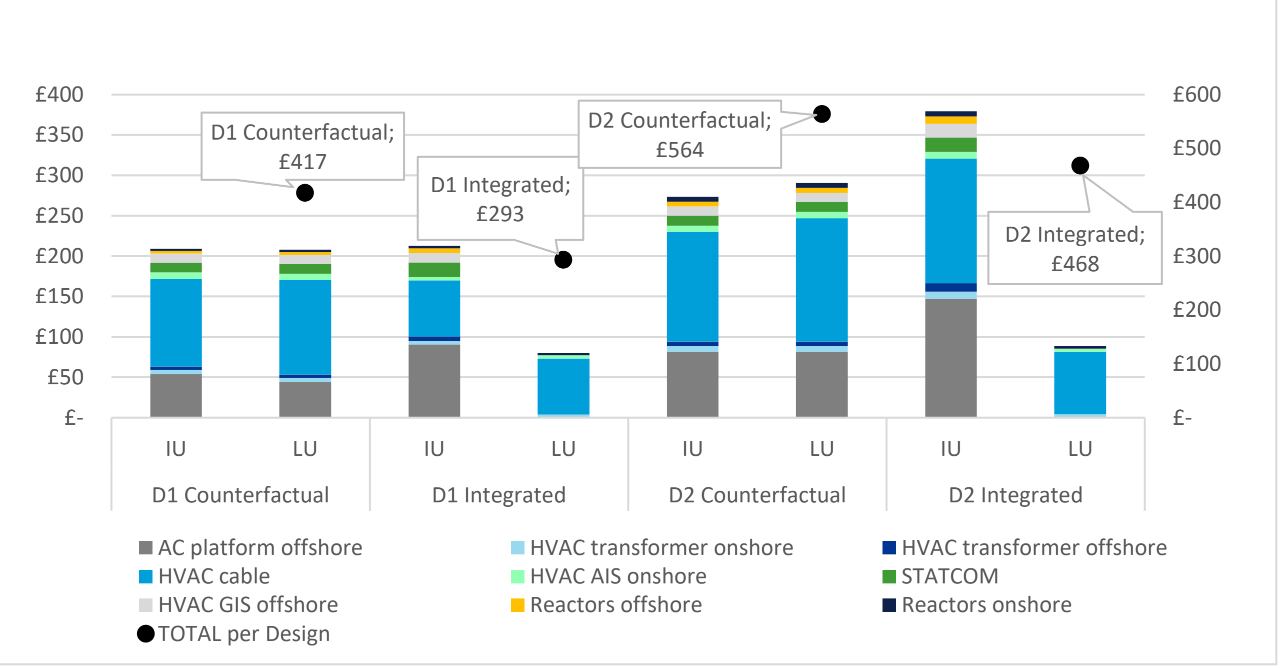

Figure 4-1 CAPEX estimate per component type and user [millions]

The saving in total CAPEX achieved in the Coordinated scenario in both designs comes at the cost of an increase in the anticipatory investment that the Initial User needs to bear. However, this increase varies substantially depending on the design due to the wind farms' size and selected component ratings. Whilst in Design 1, the total costs incurred by the Initial User are up by only 1%, the increase for Design 2 is equal to 38%. The reason for such a striking difference is that in Design 1, the rating of the cables that initially needs to be installed closely matches the total capacity of the first wind farm. At the same time, the economy of scale achieved by using a single cable of 450 MVA instead of two cables of 200 MVA results in lower cable costs for the Initial User. This contrasts with Design 2, where the Initial User needs to build two cable systems in the first step, which turns out to be over-dimensioned compared to its wind farm capacity (i.e.1060 MVA of cable capacity against 800 MW of generation capacity). In other words, it is a consequence of the maximal power rating per single HVAC cable system and the discrete ratings of cables that are selected to minimise the total cost of the offshore connection.

The underlying data is given in Table 4-1.

Table 4-1 CAPEX estimate per component type and user [mGBP]

	D1 Counterfactual		D1 Coordinated		D2 Counterfactual		D2 Coordinated	
	IU	LU	IU	LU	IU	LU	IU	LU
AC platform offshore	53.6	44.3	90.7	0.0	81.5	81.5	147.3	0.0
HVAC transformer onshore	5.5	5.2	3.9	3.9	7.2	7.2	8.6	4.3
HVAC transformer offshore	4.2	3.9	6.0	0.0	5.5	5.5	10.3	0.0
HVAC cable	108.4	116.9	69.4	69.4	135.7	152.6	154.6	77.3
HVAC AIS onshore	8.1	8.1	4.0	4.0	8.1	8.1	8.1	4.0
STATCOM	12.0	12.0	18.0	0.0	12.0	12.0	18.0	0.0
HVAC GIS offshore	11.4	11.4	11.4	0.0	11.4	11.4	17.1	0.0
Reactors offshore	3.1	3.1	6.1	0.0	6.1	6.1	9.2	0.0
Reactors onshore	3.2	3.2	3.2	3.2	6.1	6.1	6.1	3.1
TOTAL PER USER	**209.4**	**208.0**	**212.8**	**80.5**	**273.6**	**290.6**	**379.3**	**88.7**
TOTAL PER DESIGN		**417.4**		**293.3**		**564.2**		**467.9**

5 CONCLUSIONS

DNV analysed two offshore connection designs, each aiming to integrate two offshore wind farms into the onshore transmission systems. Two ways of connecting the wind farms are considered:

- The Counterfactual scenario applies the development approaches that have been utilised to date, i.e. separate single user radial connections.
- The Coordinated scenario applies the approach of a generic offshore transmission system shared by two users. The Initial User (IU) is assumed to develop the shared infrastructure by making anticipatory investment (AI), i.e. investment in offshore transmission infrastructure to support the later connection of the Later User (LU).

For the Coordinated scenario:

- The estimated CAPEX for the Initial User is provided on the basis that the Initial User contributes to the shared infrastructure.
- The estimated CAPEX for the Later User is provided on the basis that the Later User does not contribute to the shared infrastructure.

Two generic offshore wind farm designs were considered in each scenario: Design 1 and Design 2. These are shown in the Table 5-1 below.

Table 5-1 Generic Offshore Wind Farm Design Specifications

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

Our analysis has shown that for both designs, the Coordinated scenario leads to significant savings in the total CAPEX of the transmission system(s). Namely, Design 1 achieves a 30% saving from 417 to 293 million pounds, and Design 2 achieves an 18% savings from 564 to 468 million pounds.

The difference in savings is caused by the rating of the wind farm and the necessary components. The reduction is primarily driven by the decrease in the cost of the support structure and cables, both types of components being the largest contributors to the total cost. The total cost of the other component types do not vary significantly and is likely to be broadly similar for the Counterfactual and Coordinated scenarios regardless of the considered design.

The saving in total CAPEX achieved in the Coordinated scenario for both Designs comes at the cost of an increase in the anticipatory investment that the Initial User needs to bear. However, this increase varies substantially depending on the design due to the wind farms' size and selected component ratings. Whilst in Design 1, the total costs incurred by the Initial User are up by only 1%, the increase for Design 2 is equal to 38%. This difference is a consequence of the maximal power rating per single HVAC cable system and the discrete ratings of the cables, that are selected to minimise the total cost of the offshore connection.

We conclude that the actual increase in the anticipatory costs to be incurred by the Initial User will highly depend on the exact configuration of the project in question and needs to be studied on a project-by-project basis. Our analysis, however, indicates the potentially broad range of additional anticipatory costs that need to be catered for in the corresponding regulatory framework.

6 BACKGROUND INFO ON DNV COST DATABASE

The input data for the transmission equipment unit cost is taken from DNV's in-house transmission equipment database. The database is developed based on public data about offshore wind and interconnector projects realised in the North Sea. This database primarily concerns German, Dutch and British projects and is continuously updated with the most recent data from newly built projects. This process ensures it remains relevant for the latest developments.

The cost elements include the cost of equipment supply, installation and transportation, civil works, project management (EPCI PM cost), right of ways, risk contingency and profit margin. The R&D cost is also included but differs between mature technologies and new technologies. In this project, we have not included any products still under development, so the R&D portion is low. This cost is implicitly included in the cost of equipment. The cost level shown in the report is inflation-adjusted to the year 2021. The EPCI project management cost is included for each category of component/subsystem, as such, it is not shown as a separate cost item in the high-level project costs.