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Integrated Transmission Planning and Regulation (ITPR) project: final conclusions

Impact Assessment – Supporting Document

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Overview:

This document sits alongside our final conclusions on the Integrated Transmission Planning and Regulation (ITPR) project. We have previously published a draft impact assessment, embedded in our draft conclusions.

Having considered responses to our draft conclusions, we have decided to enhance the role of the System Operator and to take forward changes to the delivery arrangements for GB electricity transmission infrastructure.

In this document we set out our assessment of the impact of our decision. This includes consideration of the costs and benefits for consumers and industry participants.

Contents

1. Introduction

1.1. We have developed our impact assessment (IA) in line with our IA guidance,[1] and have used a number of sources to identify and assess the benefits, costs, and relevant distributional effects of our decision.

1.2. Our draft impact assessment was embedded in our draft conclusions. Some of the responses to that consultation requested further details of the benefits and costs of enhancing the System Operator's (SO's) role and extending the use of competitive tendering to onshore transmission assets.

1.3. For our final conclusions, we have separated out our IA. This incorporates our previous analysis, together with updates, following consideration of responses to our consultation.

1.4. Our policy decision is set out in our decision statement and supplementary appendices. The other policy options we considered are set out in our draft conclusions.

1.5. In the following chapters we set out our view of the relevant impacts, including distributional effects and strategic and sustainability considerations for each key area of our decision.

Post-implementation arrangements

1.6. We intend to review the effectiveness of our measures to enhance the SO's role through ongoing scrutiny and approval of relevant outputs (eg the network options assessment (NOA) methodology, National Grid Electricity Transmission's (NGET's) compliance statement, and subsequent compliance reports). We will evaluate the benefits of introducing competitive tendering to onshore transmission once we have completed the first tender (or round of tenders).[2]

[1] Ofgem, 'Impact Assessment Guidance', 1 October 2013: https://www.ofgem.gov.uk/ofgem-publications/83550/impactassessmentguidance.pdf.

[2] We have recently published an evaluation of savings from the first round of offshore transmission tenders. CEPA/BDO, 'Conclusions of Consultation on the Evaluation of OFTO Tender Round 1 Benefits', 19 September 2014: https://www.ofgem.gov.uk/publications-and-updates/conclusions-consultation-evaluation-ofto-tender-round-1-benefits.

2. Impact of enhancing the SO's role

2.1. We have decided to enhance the role of the SO and implement measures to mitigate resulting conflicts of interest.

2.2. In enhancing the SO's role we are seeking to ensure that the network is planned in an economic, efficient and coordinated manner. Our conflict of interest measures are intended to provide cost-effective mitigation of the conflicts that arise from enhancing the SO's role.

2.3. Our assessment of the impact of this decision is set out below. This is based on analysis undertaken for our draft conclusions, together with relevant updates to address responses to our draft conclusions. Our assessment contains three parts:

- The impact of our decision to enhance the role of the SO.
- The impact of our conflict mitigation measures.
- The impact of our decision on different groups, geographical distributional impact and strategic and sustainability considerations.

Impact of our decision to enhance the role of the SO

Benefits

2.4. We have concluded that the SO is well placed to undertake a coordinating role in system planning. This will build on its existing responsibilities managing the day-to-day operation of the GB electricity transmission system by giving it a greater role in planning the network, providing increased information on investment needs and helping to assess and develop options. In doing so we seek to balance the benefits of coordination in planning and operating the network with the benefits of investment decisions sitting with those best placed to take them.

2.5. We consider that this increased role for the SO in planning the network will help ensure **better coordination** across different parts of the network (onshore, offshore and interconnection). This will support the development of the network in an economic and efficient way. There are potentially significant benefits to be achieved from coordinating the investment required both within and across regimes.

- The benefits of having a more integrated approach to development of offshore networks (including offshore generation connections and interconnectors) have been set out in a report we commissioned as part of our offshore coordination work[3] and by reports produced by the 'NSCOGI'[4] and 'ISLES' groups.[5]

- We also consider that there could be benefits from a more joined-up approach to future interconnection needs and GB network reinforcements, as this can allow more efficient and timely development of interconnection and the onshore network. For example, if the SO's interconnector modelling suggested strong consumer benefits from additional interconnection to a particular market then this could inform the case for reinforcement of the GB network in the area where such new interconnection would best connect.

- The new SO roles are also a key enabler to ensuring coordination opportunities are identified across the network and taken forward where they could provide for the most economic and efficient solutions.

2.6. The scale of the benefits from coordination across different parts of the network is difficult to quantify given uncertainty as to how and where the network will need to develop in the future. A major part of this uncertainty concerns where different types of generation will come forward and on what scale. In addition, some types of coordination will only be possible if new grid technologies become commercially viable (particularly with regard to whether high voltage direct current (HVDC) cables can be linked to form a meshed network). We are seeking to manage this uncertainty by creating a framework for system planning that ensures opportunities for efficient coordination can be taken forward as and when they emerge.

2.7. The SO's involvement in **identifying, assessing and developing options** for potential major network reinforcement projects, together with the transparency and scrutiny that will occur through the NOA process, should help ensure that the most economic and efficient solutions are identified.

- The SO will have a role in the early development of some options to meet system needs (eg desktop analysis of the capacity to be provided, technology choices and high level routing). This relates to options for

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[3] This study showed there may be potential savings of between £0.5-£3.5bn from coordination between Crown Estate Round 3 offshore wind zones, depending on factors such as how offshore wind deployment progresses, and the availability of technology required for large, complex offshore projects. TNEI/PPA, 'Offshore Transmission Coordination Project – Final Report for the Asset Delivery Workstream', 2011: www.ofgem.gov.uk/ofgem-publications/75447/tnei-7098-03-asset-delivery-workstream-release-15-12-2011.pdf
[4] The North Seas Countries' Offshore Grid Initiative (NSCOGI), 'Initial Findings – Final Report – Working Group 1 – Grid Configuration', 16 November 2012: http://www.benelux.int/files/1414/0923/4478/North_Seas_Grid_Study.pdf
[5] Irish-Scottish Links on Energy Study (ISLES), 'Executive Summary', April 2012, p.5: http://www.scotland.gov.uk/Resource/0039/00395581.pdf

onshore transmission which would be subject to competitive tendering and non developer-led wider network benefit investment (WNBI). This means that a full range of options should be considered. Without a clear responsibility for the SO to undertake this work, efficient solutions may be missed.

- Earlier scrutiny of options and consistency of assessment of options (through the NOA process) should ensure that strategic wider works (SWW) needs cases and offshore gateway submissions submitted to us are well developed and contain a full range of analysis to help inform both the transmission owners' (TOs')/developers and our decision-making processes. For example, the NOA process will require more transparency and scrutiny of how options are prioritised through the development process.

- We consider that our decision to enhance the SO's role in this way to be consistent with the RIIO principles and that this will enhance the TOs' ability to develop the network.

2.8. By requiring the SO to lead the **offshore gateway assessment process** we think consumers will be better protected as it will ensure the process is applied consistently to all projects led by offshore developers that include requirements for WNBI. We consider that the SO is best placed to lead the gateway assessments because it can provide a holistic view of the network and is therefore well placed to identify the most economic and efficient approach to meeting system requirements. The SO also has access to the information we will require to make a decision on the rationale for including the WNBI in the scope of the project. As the SO is already responsible for making connection offers in line with the requirement to develop and maintain an efficient, coordinated and economical system of electricity transmission, the addition of this process involves only minimal changes to the existing framework.

2.9. The new role for the SO in **interconnector modelling** will provide additional information to developers on what opportunities exist, and so should support them in developing their projects. The SO's analysis will also support our decision-making, and could assist the government with its decision-making process on European 'projects of common interest'.[6] In addition, we expect the additional roles for the SO in interconnector modelling will mean that it will play a greater role in ENTSO-E modelling.[7]

[6] Information about projects of common interest and how they are treated in the ten year network development plan (TYNDP) can be found on the European Network of Transmission System Operators for Electricity (ENTSO-E) website: https://www.entsoe.eu/major-projects/ten-year-network-development-plan/FAQs/Pages/6.-Projects-of-Common-Interest.aspx
[7] ENTSO-E produces annual TYNDP reports, which include modelling and analysis of interconnector need and capacity: https://www.entsoe.eu/Pages/default.aspx

2.10. We have also set out in our decision statement other roles we consider the SO should undertake:

- In most cases (outage coordination, liaison with distribution network operators (DNOs) and power quality) we are simply reiterating or clarifying roles we believe the SO should already being doing.

- Formalising the process for determining the appropriate connection offer from a whole network perspective should improve the transparency of the connections process and help ensure offers are economic and efficient.

Costs

2.11. Despite the benefits outlined above, any change in the roles and responsibilities for system planning leads to changes in costs and risks. Specific changes in costs as a result of our decisions are:

- There will be costs associated with the increased role taken on by the SO (including the cost of implementing new procedures and additional stakeholder engagement). However, based on our initial assessment and the extent to which the SO already undertakes aspects of the roles in question, we anticipate that any additional costs will be relatively insignificant compared to the cost savings that could be achieved from a more efficient and coordinated transmission network. Some costs will be one off (such as those relating to the setting up of new systems) others will be ongoing (such as staff costs – although we would expect to see efficiency savings over time). Our initial view is that any funding requirements associated with our decision to enhance the SO should be considered in the event of a RIIO mid-period review. At that time we will undertake an appropriate assessment of costs to inform our funding decision.

- Any change in the system planning process carries the risk of potential disruption and consequential delays in investment as the new arrangements take effect. However, we think the changes we are making to the process (which build on what is already there) should not cause significant disruption or delay to investment decisions.

- A number of respondents to our draft conclusions raised concerns about the impact of our proposals on the planning process. We consider that the new NOA process will have a positive impact on the way projects are assessed. This process is not intended to add another step to the assessment process but rather improve the transparency and the efficiency of assessments. As set out in paragraph 2.7 the new arrangements should ensure that SWW needs cases and offshore gateway submissions submitted to us are well developed and contain analysis of a wide range of options.

2.12. The new SO-led gateway assessment process could create some risk for the offshore developer's project timelines. There are a number of aspects of our proposals which we think suitably mitigate these risks:

- Our flexible approach will help to ensure that the gateway assessment process remains proportionate to the investment under consideration.

- We will seek to understand the timelines for specific projects through discussions with the SO and the developer. We will consider these timelines in undertaking needs case assessment for that project.

- If a developer considers the inclusion of WNBI in its connection offer will significantly impact its ability to deliver its project then it can reject the offer made by the SO or apply to Ofgem using the existing connections determination process within the licence.

Impacts of our conflict mitigation measures

2.13. Our decision on how to mitigate potential conflicts of interest and our proposed licence modifications should substantially reduce the risk of system planning decisions becoming distorted and therefore inefficient and not in consumers' interest. It should also mitigate the risks of perceived conflicts of interest which could undermine stakeholders' confidence in a competitive regime. Without these measures, we believe there is a high chance that both real and perceived conflicts could negatively impact upon consumers' bills. For example, this could occur due to inefficient planning solutions being taken forward.

2.14. The introduction of ring-fencing and business separation arrangements will limit NGET's ability to act on conflicts. The increased transparency, enhanced scrutiny and obligations on conduct will increase the likelihood of detection.

2.15. We consider the main costs and risks associated with our decision are:

- Disruption and loss of (onshore) SO/TO synergies in England and Wales. However, given the ring-fencing will apply only to specific planning information we consider this risk to be low.

- Upfront implementation costs, including the cost of amending NGET's licence and NGET implementing relevant procedures. However, given that our proposals largely build on existing conflict mitigation arrangements (including those that exist for offshore and Electricity Market Reform (EMR)) we consider these costs should be low.

- Ongoing costs, including the costs of additional reporting and additional stakeholder engagement. Again, we consider these costs will be low given how they will likely build on additional reporting and engagement (such as the electricity ten year statement (ETYS) and NGET customer seminars).

2.16. We consider, on balance, that our decision is a proportionate response to the issues identified.

Different groups, geographic distributional impact and strategic and sustainability considerations

Consumers

2.17. As GB consumers ultimately bear the costs of the transmission network, they will benefit from the cost savings that can be achieved from a more efficiently designed and coordinated network. Our decision will lead to more efficient transmission costs which will feed through to lower network charges to help keep consumer bills down, while a network that efficiently meets the needs of its users will ensure consumers' electricity supply is secure as it decarbonises over time.

2.18. We do not foresee any additional impacts of our proposals on vulnerable consumers as a subset of GB consumers. However, consumers who have lower incomes will see greater relative improvements in the affordability of their electricity.

Industry Participants

2.19. Our decision will affect industry participants differently.

- Giving the SO additional roles in system planning will directly increase responsibilities and costs for the SO, but benefits will be seen for TOs and transmission developers in the information and advice available to them when making investment decisions. We will also be consulting on minor changes to the TO licences to ensure the SO has the information it needs from the TOs to carry out its new role.

- Our decision to mitigate potential conflicts of interest will primarily affect NGET, and the detail of how it will be affected will become clear as the changes in roles are implemented. Our decision will benefit other industry participants by giving them greater confidence that NGET will conduct its enhanced SO role in a fair and transparent manner.

Geographic distributional impact

2.20. Through its existing SO and TO functions, NGET is already responsible for network planning in England and Wales. However, following our decision NGET will also have an increased role in network planning in Scotland, for offshore developments and for interconnection. We think the benefits of a holistic approach to network planning will benefit the whole of GB. Based on the current cost recovery methodology the costs of implementing the enhanced SO role will be shared across network users.

Strategic and sustainability considerations

2.21. We have considered how enhancing the role of the SO would contribute to a sustainable and secure energy supply for GB consumers.

2.22. The electricity transmission network is a key element in the transition to a low carbon energy supply, in creating an electricity system that is secure and resilient to external shock, and in encouraging technology development and market participant diversity.

2.23. Since generation mix and locations will change as GB and other European countries decarbonise their energy systems, substantial investment will be required for the network to continue to be reliable and secure. The new arrangements will provide for a clear and transparent methodology for developing options in the face of uncertainty. This will enable forward-looking planning where whole-of-system needs are considered, economic and efficient reinforcement options are developed, and long-term investment decisions are taken in the interest of existing and future consumers.

2.24. Much of the anticipated transmission investment over the coming decades is aimed at ensuring the transmission system enables low carbon electricity generation and use. On the whole, we expect our decision to decrease the costs of this needed investment. For example, coordinated solutions can require less physical infrastructure, leading to cost savings and lower environmental impact. These impacts would contribute to reducing the overall costs of moving to low carbon technologies, assisting with their deployment and use in GB.

3. Impact of extending the use of competitive tendering in transmission

3.1. We have decided **to extend the use of competitive tendering to onshore assets that are new, separable and high value**. We will run competitive tender exercises to identify parties to construct, own and operate these assets.

3.2. We are seeking to use competitive tendering where the potential benefits of doing so, such as cost savings and innovation, outweigh the potential costs, such as administrative and interface costs. We believe that this will be the case for onshore transmission assets that are new, separable and high value. Assets that meet these criteria can be more easily and efficiently scoped for tendering and because they are high value, the potential gains are high compared to the transaction costs of the tender process.

3.3. The case for extending the use of competitive tendering is informed by the expectation that applying competitive pressure will lead to better value for consumers. We expect that competition will reduce costs by encouraging greater efficiency and innovation. It is also in line with our duty to carry out our functions in a manner we consider best calculated to further our principal objective (which is to protect the interests of existing and future consumers), wherever appropriate by promoting effective competition.[8] In this IA we have sought to include illustrations or explanations of costs and benefits wherever possible, and have also set out the impact of similar policies on the offshore network and in other countries.

3.4. We have developed our IA in line with our guidance document.[9] Our draft conclusions included an assessment of the impact of extending the use of competitive tendering. Here we have updated and finalised our analysis, responding to stakeholders' requests for further information. Our approach reflects the difficulty and uncertainties involved in trying to quantitatively predict the costs and benefits of introducing competitive delivery in new areas. In assessing the impacts of extending the use of competitive tendering, we have therefore:

- Sought to assess these costs and benefits quantitatively where possible, but we do not see value in using numbers where uncertainties would make it spurious to do so. In such cases, we have instead given a qualitative description of our expectation of the nature and relative importance of the costs and benefits.

[8] Section 3A, Electricity Act 1989.
[9] Ofgem, 'Impact Assessment Guidance', 1 October 2013, p19: https://www.ofgem.gov.uk/ofgem-publications/83550/impactassessmentguidance.pdf

- Set out some illustrative quantitative scenarios and explained the level of benefits that would need to be achieved in order for the benefits to outweigh the costs.

- Used comparative examples from GB and other countries.

- Assessed the impacts on different groups and geographic areas, and assessed the relevant strategic and sustainability considerations.

3.5. This enables us to expect that the benefits of a competitive approach **will outweigh the costs of tendering and bring benefits for existing and future consumers**. We anticipate that competitive pressure will drive innovation and expenditure savings, while consumers will also benefit from a reduction in the cost of investment in low carbon generation.

Anticipated costs, benefits and risks of extending the use of competitive tendering

3.6. We set out our assessment of the costs and benefits associated with extending the use of competitive tendering below, in line with the approach set out in paragraph 3.4. There are a number of sources of uncertainty that must be accounted for in our assessment.

3.7. First, the pipeline of projects that could be suitable for competitive tendering is currently unclear. While the changing energy mix and planned investments in renewable generation mean that new, separable and high value projects are likely to come forward over the next decade, it is uncertain how many projects will be needed and when they will be required. The level of costs and benefits of competitive tendering will depend on the number of projects that are tendered and their value.

3.8. Second, as we describe below, we expect competitive tendering to have benefits in a range of areas. As our IA guidance notes, it is particularly complex to quantify the efficiency and dynamic benefits of opening markets to competition, such as the scope of increased innovation and the introduction of new products, services and technologies. We do not consider that it is reasonable to estimate the level of benefits in each area and arrive at an estimation of total benefits, partly because of uncertainty over the exact benefits of subjecting capital investment to competitive tendering, and partly because many of the dynamic effects of introducing competition are hard to anticipate and monetise (for example, innovation).

3.9. Third, there is uncertainty over the scale of the costs that will be incurred as a result of extending the use of competitive tendering and the extent to which these will be offset by reductions in the cost of existing activities. On the basis of our experience with the offshore transmission regime we are able to estimate the initial set up costs, our ongoing tender costs and the costs incurred by bidders, and have included these estimates in the analysis below. The additional costs in some areas, such as our costs of running tenders, have to be set against costs that will be reduced in others, such as our costs of assessing SWW projects.

Benefits

3.10. **Capital and operational cost savings –** competitive tendering will place downward pressure on capital and operating expenditure. In regulating the incumbent TOs we have to estimate the efficient cost of constructing and operating new projects, based on the funding requests submitted to us by TOs. We can draw on independent expertise and benchmarks from other projects, but this cannot completely resolve the problem of information asymmetry where we do not know the true costs likely to be faced by monopoly companies. It is well established that effective competition can enable efficient costs to be revealed, since the pressure of competition will encourage parties to reveal the true cost of completing a project. Parties competing to be appointed the successful bidder are likely to put forward lower costs than an incumbent TO estimating the costs of constructing and operating a particular asset under a traditional price control approach.[10] The need to achieve these savings in order to be competitive may also drive innovation, as discussed below.[11]

3.11. Some incumbent TOs noted in their responses to our draft conclusions that they already use competitive tendering when they engage the supply chain. We consider that opening overall project development to competition will create scope for further efficiencies, such as through encouraging innovative and more cost-efficient procurement, risk management, project management and operations and maintenance strategies.

3.12. **Innovation –** competitive pressure and the involvement of new parties is likely to drive innovation. On an individual project basis, innovation can result in lower costs and better value for consumers as bidders seek to create innovative and cost-saving solutions in order to submit competitive bids. It also has wider benefits – innovations adopted by one party may be relevant for the rest of the industry and could help to drive down costs across the board, leading to benefits for consumers.

3.13. Depending on the tender model chosen, we could expect innovation in areas such as technology, design, supply chain management, the raising of finance and operations processes. For example, in financing, Greater Gabbard OFTO was the first

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[10] The CEPA/BDO study on the impact of the offshore transmission regime showed that offshore TOs (OFTOs) achieved significantly lower costs when compared to a counterfactual in which incumbent TOs operated the offshore transmission systems as part of the onshore price control.
CEPA/BDO, 'Conclusions of Consultation on the Evaluation of OFTO Tender Round 1 Benefits', 19 September 2014: https://www.ofgem.gov.uk/publications-and-updates/conclusions-consultation-evaluation-ofto-tender-round-1-benefits.
[11] The level of potential savings may depend on the tender model used. For example, a late tender model may improve the ability of competition to reveal true costs, while an early tender model may give greater scope for innovation in high level design and technology choice.

UK and second EU project to use the innovative European Investment Bank (EIB) project bond credit enhancement (PBCE) product,[12] reducing the cost of capital and providing value to consumers. In technology development, TC Ormonde OFTO Ltd has been awarded funding through the 2014 network innovation competition to develop an offshore cable repair vessel and universal cable joint.[13] This is intended to reduce the cost of offshore maintenance and produce benefits for consumers.

3.14. **Diversifying sources of labour and capital –** opening up investment opportunities to new parties allows different sources of labour and capital to enter the industry. This has benefits in financing costs and in driving innovation, as noted above. The involvement of new parties also enables us to increase the number of data sources we can use to benchmark the cost submissions of TOs and other transmission developers when deciding on the allowed revenue for a particular output. Competitive tendering will, therefore, have benefits for the effectiveness of regulation across the transmission sector, not just for projects that are subject to a competitive tender.

3.15. **Financing –** we would expect bidders in a competitive process to put forward financing solutions that provide value to consumers. The experience of the offshore transmission regime is that bidders have been able to draw finance from a range of new sources and consumers face a cost of capital that is ultimately comparable to incumbent TOs.

3.16. **Enabling investment in low carbon generation –** a significant effect of extending the use of competitive tendering, which follows on from the other benefits set out above, is that it will enable investment in low carbon electricity generation. Cost savings driven by innovation and the competitive process will lower transmission charges and make investment in low carbon generation more economically viable. Consumers will benefit from carbon savings and lower costs associated with meeting environmental targets.

Costs

3.17. **Set-up costs –** there will be some costs incurred by Ofgem when setting up the onshore competitive tender regime. We anticipate that to a large extent we will be able to build on the systems and processes that have been put in place by the offshore regime, but there are some specific costs that relate to the work set out in the plan for implementing our decision outlined on paragraphs 3.12-3.13 of our decision statement. We estimate that the set-up costs will be £2-3m, but for the purposes of the scenario analysis below we have taken the conservative estimate of

[12] Ofgem, 'Ofgem grants offshore transmission licence for Greater Gabbard wind farm', 26 November 2013: https://www.ofgem.gov.uk/press-releases/ofgem-grants-offshore-transmission-licence-greater-gabbard-wind-farm
[13] https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-competition/transmission-capital-partners

£3m. These costs will be incurred prior to launching the first tender, regardless of the subsequent volume or frequency of tenders.

3.18. **Ofgem tender costs –** We incur costs when running competitive tenders: these relate broadly to staffing, technology and external advice on legal, technical and financial matters. Based on our experience from the offshore regime, we think that the long-run average of our tender costs will be approximately one per cent of the value of the assets being tendered. We acknowledge that evaluating bids for tenders that involve construction proposals may be more costly than for previous generator build tenders to appoint OFTOs, but the value of one per cent is a conservative estimate[14] and we would expect the average cost to be in this region.

3.19. Costs may vary for individual projects. There are some fixed costs associated with running tenders and the variable costs may not rise in direct proportion to asset value. Tender costs will therefore form a higher percentage of asset value on lower value projects and a lower percentage on higher value projects, but we expect that these will be balanced out over time. There may also be efficiencies to be realised from tendering a number of projects in a single tender round as the offshore transmission regime has done, although this would depend on project delivery timescales.

3.20. While we will incur costs when running tenders, they will, to an extent, be offset by costs avoided in other areas. We currently incur costs when evaluating SWW projects. If these projects are instead subject to a competitive tender, the resources that would have been devoted to project evaluation will be reallocated.

3.21. **Bidder costs –** we also recognise that bidders will incur costs when preparing bids and, in the case of the successful bidder, engaging in the processes required ahead of being granted a transmission licence (such as further due diligence and acquiring necessary assets). The CEPA/BDO report estimated successful bidder costs of £35m over the nine projects in offshore tender round 1 (TR1).[15] As with our tender costs, bidder costs will be offset by the costs that TOs will not need to incur in developing assets themselves, such as in submitting cost estimates to us and undertaking their own due diligence.

3.22. **Interface costs –** in our draft conclusions we noted that there may be additional costs associated with managing interfaces between the parties involved in the operation of the transmission system. Some respondents to our draft conclusions also considered that with an increased number of parties, the system becomes more difficult to manage. However, the network already functions with a single SO, three

[14] In this context, a 'conservative' estimate is one which is at the upper bound of the estimated range of costs for a particular item.
[15] CEPA/BDO 'Conclusions of Consultation on the Evaluation of OFTO Tender Round 1 Benefits', 19 September 2014, p12: https://www.ofgem.gov.uk/publications-and-updates/conclusions-consultation-evaluation-ofto-tender-round-1-benefits. This figure includes the successful bidders' bid costs and other costs incurred ahead of licence grant.

onshore TOs and a multitude of OFTOs, DNOs and interconnector operators. There may be an incremental interface cost associated with adding new parties to the network, but we do not expect that it will be significant enough to outweigh the potential benefits of competitive tendering. Industry codes and standards are already in place to manage the relationships between parties. These can be amended to accommodate competitively appointed TOs and ensure that industry relationships are managed in a constructive and efficient manner.

3.23. **SO costs –** the SO will complete early development work and some preliminary works prior to a tender. The nature and extent of these works will depend on the tender model that is used. While these activities may involve additional cost for the SO, the costs will be offset by the work no longer undertaken by TOs. There may be some limited duplication of functions, but we do not think these are likely to be significant. We will consider and consult on the arrangements further as we develop the detailed framework.

Risks

3.24. **Delay risk –** Some responses to our draft conclusions highlighted a potential risk that projects could be delayed due to the time taken to run a tender. For projects where some early development work has already been completed we will work to develop a tender process that fits with project timings and does not cause undue delays. In the longer term, competition could bring about innovative processes that lead to more timely delivery of assets. We anticipate that the framework we develop will include incentives on the competitively appointed party to deliver the project in a timely manner, and we also expect that the robustness of bidders' delivery plans will form a key aspect of our tender evaluation process. We note that projects built by incumbents have not been immune from delays.

3.25. **Consumer risk –** the protection of consumers' interests is paramount. The introduction of a tender process carries some risk. This could include, for example, the risk that we could run a tender for a project and then, based on external factors such as a changing generation mix, decide that the project is no longer in the interests of consumers and is not needed. In this case there would be costs associated with the aborted tender. We think that this risk, and other similar risks, can be managed through careful design of the project development and tender processes. We will consider them carefully during the detailed development of the tender framework.

Scenario Analysis

3.26. The uncertainties around the pipeline of projects meeting our criteria for competitive tendering and the exact costs and benefits mean that we do not consider that it is possible to arrive at a single monetary estimate of the impact of competitive tendering. Instead, we have outlined some scenarios to demonstrate the potential scale of some costs and benefits. We recognise that these scenarios are not exhaustive; this analysis is illustrative and can only address a small part of the range of benefits that we expect to arise from the extended use of competitive tendering. It does show, however, that even under a conservative scenario, the cost savings do not need to be large for there to be benefits for consumers.

3.27. We made the following assumptions when constructing the scenarios:

- **Project value –** the value of transmission investments varies greatly, from the £1bn Western HVDC link[16] and £1.1bn Caithness Moray project[17] to smaller reinforcements and connections. There is likely to be a range of project sizes that meet the 'new' and 'separable' criteria and are high value (which we have previously suggested could be above a threshold of £50-100m), but we have assumed for the purposes of this scenario analysis that tendered projects are worth £500m each. This is based on analysis of the estimated value of potential future transmission projects, although the actual pipeline is likely to include some projects of a higher and some projects of a lower value.

- **Set-up costs –** as noted above, we have estimated our set-up costs to be £2-3m, but have adopted the more conservative estimate of £3m here. These would be incurred prior to the first tender, regardless of the size of the eventual pipeline.

- **Ofgem tender costs –** we have estimated the cost of running a tender at one per cent of the capital value of the assets. Efficiencies may be achievable for higher value projects or where projects can be grouped into tender rounds, but we have conservatively assumed here that there is only one project in each round. The cost of running tenders will also be offset by avoided costs that will not be incurred in setting revenue allowances for TOs during the price control period.

- **Bidder costs –** using the example of the offshore TR1, we estimate successful bidder costs, on a long term average basis, to be approximately two per cent of the value of the capital value of the assets. This is a conservative estimate: it includes not just the cost of preparing the bid, but of reaching the point where a licence is granted and the successful bidder acquires the transmission assets. As with our tender costs, lower relative costs may be achievable for higher value projects or for projects that can be grouped into tender rounds. Bidder costs will be offset to an extent by a reduction in costs that would have been incurred by the incumbent TO, so the net cost to consumers will be lower than if bidder costs are considered in isolation.

[16] http://www.westernhvdclink.co.uk/
[17] Ofgem, 'Decision on our assessment of the Caithness Moray transmission project', 16 December 2014: https://www.ofgem.gov.uk/publications-and-updates/decision-our-assessment-caithness-moray-transmission-project.

3.28. Figure 1 below shows four scenarios for competitive tendering. The CEPA/BDO report on the impact of the offshore transmission regime found savings of 14 per cent when compared to incumbent TO delivery.[18] These scenarios suggest that if even less than half of these savings are replicated onshore, there could be significant benefits for consumers.

3.29. As noted in paragraphs 3.22-3.23 above, we do not expect the costs that we have not quantified here to be significant. If they are significant, then the savings would be diminished, but the scale of the savings experienced in the offshore regime and in the international examples quoted below is such that we would still expect to see benefits for consumers even if the interface or SO costs are higher than expected.

Figure 1: Scenario analysis of competitive tendering of £500m projects

Scenario	One Project £500m[19]	Two Projects £1bn	Three Projects £1.5bn	Four Projects £2bn
Set up cost	£3m	£3m	£3m	£3m
Ofgem tender costs	£5m	£10m	£15m	£20m
Bidder costs	£10m	£20m	£30m	£40m
Total costs[20]	£18m	£33m	£48m	£63m
Minimum savings (as a percentage of asset value) required so that benefits outweigh costs	3.6%	3.3%	3.2%	3.15%

[18] It should be noted that this is expressed as a percentage of the net present value of the total tender revenue streams (TRSs) for TR1. If the estimates of our tender costs and bidders' costs were expressed in these terms rather than as a percentage of capital value, they would be less than one and two per cent respectively.
[19] Projects are assumed to be £500m each. This is based on the potential project pipeline. However, the 'high value' threshold for tendering could be lower, and we have previously thought it to be in the £50m-£100m range. If projects were lower in value, then the ratio of tender costs per £-value of the project would be higher and greater savings would be required to ensure savings outweighed the tender costs.
[20] This does not account for costs that we have not quantified such as interface and SO costs, and also does not account for costs that will be offset in other areas.

Comparative Examples

3.30. The competitive tendering of OFTO licences in GB has already brought benefits for GB consumers. Throughout the world, and particularly in North and South America, there are many examples of where transmission tendering has led to cost savings. A selection of these is discussed in figure 2 below.

Figure 2 – Examples of benefits of use of competitive tendering in transmission delivery

Example and description	Benefits
GB offshore transmission[21] We are responsible for managing the competitive tender process through which offshore transmission licences are granted to own and operate offshore transmission assets.	We recently published a report by CEPA and BDO evaluating the benefits of TR1. The report demonstrated that competitive tendering in offshore transmission resulted in considerable financing and operating cost savings in comparison to a range of counterfactuals. When compared with the most relevant counterfactual for this IA – delivery by monopoly TOs under a price control – the cost savings were estimated to be approximately 14% of the total expected revenue stream.[22] These benefits relate to the specific scenario of offshore transmission in TR1. TR1 used the generator build model, where the OFTO is appointed to operate, own and maintain a point-to-point transmission link. Competitive tendering for new, separable and high value onshore assets is likely to use a different tender model with additional challenges, but there may also be greater scope for competition to yield innovation and efficiencies in the development and construction stages, and we believe that similar or additional benefits are likely to be captured.

[21] CEPA/BDO, 'Conclusions of Consultation on the Evaluation of OFTO Tender Round 1 Benefits', 19 September 2014: https://www.ofgem.gov.uk/publications-and-updates/conclusions-consultation-evaluation-ofto-tender-round-1-benefits.
[22] This estimated saving does not account for the costs incurred by Ofgem or bidders during the tender process, which are described in Section 1 above.

Texas (United States)[23 24] The Public Utility Commission of Texas (PUCT), the regulator, used competitive tenders to appoint transmission developers for a large scale expansion of the transmission network needed to meet a renewable energy target of 18.5GW.	Tenders were open to incumbents and new entrants, with seven projects being allocated to incumbents and eight to new entrants. Construction began in late 2010 and 3,600 miles of new transmission lines were delivered over three years.
Argentina[25] System planning is driven by connection users (generators, distributors or large customers) who make proposals and vote on these, confirming their willingness to pay the costs of the new transmission lines. The assets are then delivered via competitive tendering.	A review of the use of competitive tendering from 1993 to 2003 found: • over two thirds of winning bids below the specified maximum; • new entrants to the development of transmission (the incumbent won less than one fifth of tenders); • a significant expansion of the transmission system (20 per cent in length over ten years); and • significant capex and opex cost reductions (roughly halved over first five years). Although the level of detail of design specifications increased over time, Imperial College notes that this seems not to have stifled innovation but enabled it, attracting large numbers of specialised bidders.
Brazil[26] The transmission system central planner uses annual capacity auctions to determine the necessary transmission system expansion, which is approved by government. Reinforcements are then auctioned for delivery. Candidates compete for a 30-year RPI-indexed annual revenue stream to construct, own, operate and maintain the asset.	From 1999 to 2008, 87 transmission concessions were auctioned. The competitive process led to • a high volume of bidders (112, many foreign; private, public-private partnership and state-owned), indicating limited transaction costs and low barriers to entry; • good equipment price discovery; and • a downward trend in revenue per km.

[23] Imperial College London and Cambridge University Electricity Policy Research Group, 'Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery', June 2013, pp 74-80: https://www.ofgem.gov.uk/ofgem-publications/52727/imperialcambridgeitprreport.pdf.
[24] The Texas example also draws on further details from the PUCT website, found here: http://www.texascrezprojects.com/overview.aspx.
[25] Imperial/Cambridge Report, pp 57-60.
[26] Imperial/Cambridge Report, pp 66-70.

Chile[27] Competition in transmission delivery was introduced in 2004, with auctions managed by the independent SO. Participants bid for a project for a particular capacity, technology and number of towers, but must themselves decide on routing, obtain landowner consents and undertake environmental impact studies.	In 2011, in the second round of auctions, eight projects were awarded to a range of new entrants. The auctions have been useful in terms of cost discovery, with winning bids consistently undershooting the maximum acceptable bid thresholds.

3.31. Some respondents to our draft conclusions noted that the international examples cited are not necessarily directly comparable to competitive tendering for onshore assets in GB. We acknowledge that there are differences in the regulatory and commercial environments in each country, and that there are differences between GB onshore and offshore transmission. However, it is clear that in each case significant benefits have been realised from tendering. Some respondents noted that the regulatory regimes in some countries are not as robust as the GB regime, and therefore there is more room to achieve improvements by introducing competitive tendering. While our RIIO regime achieves value for consumers, we are always looking for ways to improve arrangements for consumers. Competition is an effective tool for price discovery and to encourage new approaches, and it is in the interests of consumers to use it where costs can be minimised while maintaining incentives for timely delivery and high quality construction, operation and management.

Different groups, geographic distributional impact and strategic and sustainability considerations

Consumers

3.32. Consumers will be the ultimate beneficiaries of our proposed changes. Efficient transmission costs will feed through to lower network charges to help keep consumer bills down, while a network that efficiently meets its needs will ensure consumers' electricity supply is secure as it decarbonises over time.

3.33. We do not foresee any additional impacts of our decisions on vulnerable consumers as a subset of GB consumers. However, consumers who have lower incomes will see greater relative improvements in the affordability of their electricity.

[27] Imperial/Cambridge Report, pp 70-74.

Industry Participants

3.34. Under a traditional price control approach, incumbent TOs are responsible for making investments in their transmission area, and receive a regulated return on their investments. Extending the use of competitive tendering may result in some projects being developed by new entrants rather than by the incumbent onshore TOs.[28] In such cases the incumbent TO would not receive the regulated returns for that investment; these would instead be received by another party. Potential new entrants will benefit from the opportunity to develop onshore transmission assets, which previously has not existed. This is a potential transfer of future returns from one party to another. It is a natural consequence of a competitive market and would be justified by an increase in overall social welfare produced through the benefits to consumers and the wider industry, noted above. As we develop and consult on the detailed arrangements for the use of competitive tendering onshore, we will consider how specific elements of the regime will affect industry participants.

3.35. Many generators, particularly low carbon ones (including new technologies such as tidal power) and those in more remote areas, could benefit from earlier connection dates because the tendering process could result in bidders being appointed who, among other things, are able to deliver projects in a timely manner. Competitive tendering would also lower the overall system costs, meaning the costs faced by system users, including low carbon generators, could be lower, improving the business case for investment.

Geographic distributional impact

3.36. Our decision to competitively tender some onshore SWW investments in RIIO-T1 could also have geographic impacts. Many RIIO-T1 SWW projects are located in Scotland. Therefore, in RIIO-T1, there could be more use of tendering in Scotland, though this does not mean that tendering may not also be used for some SWW projects in England and Wales. It is unclear what the geographic impact of tendering could be for RIIO-T2 and beyond, since investment plans are yet to be developed.

3.37. These potential geographic differences in tendering for RIIO-T1 mean that generators in Scotland could benefit more than others. This is because the charges that generators pay to use the transmission network are determined by factors such as the configuration of the system at a particular location, the design of the generator connection and the cost of the reinforcement to the local network and any deeper reinforcements required. Through tendering, we expect these costs to be lower than they would otherwise be. However, from a transmission charging perspective, cost savings through tendering would be expected to produce net gains

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[28] We indicated at RIIO-T1 final proposals that SWW projects could be subject to competitive delivery. For NGET RIIO-T1 final proposals, see https://www.ofgem.gov.uk/ofgem-publications/53599/1riiot1fpoverviewdec12.pdf, p9 and for Scottish Power Transmission and Scottish Hydro Electric Transmission RIIO-T1 final proposals, see https://www.ofgem.gov.uk/ofgem-publications/53747/sptshetlfpsupport.pdf p15.

across the system for all users (both generation and demand), with users in England and Wales also gaining where wider system developments are delivered at lower cost.

Strategic and sustainability considerations

3.38. We have considered how our decision would contribute to a sustainable and secure energy supply for GB consumers.

3.39. The electricity transmission network is a key element in the transition to a low carbon energy supply, in creating an electricity system that is secure and resilient to external shock, and in encouraging technology development and market participant diversity.

3.40. Much of the anticipated transmission investment over the coming decades is aimed at ensuring the transmission system enables low carbon electricity generation and use. On the whole, we expect our decision to decrease the costs of this investment. These impacts would contribute to reducing the overall costs of moving to low carbon technologies, assisting with their deployment and use in GB.

3.41. An increase in the number of industry parties could lead to complexity and increased interfaces. However there may be some offsetting benefits for greater resilience in the network from reduced reliance on a limited number of companies. We intend to ensure the reliability and availability of competitively tendered assets through the design of the competitive regime. During the tender process we will consider bidders' experience and the robustness of their plans to manage the assets, while on an ongoing basis we anticipate placing incentives on performance through the licence. This has been the case for offshore tenders, where bids have been evaluated on the basis of price as well as financial and technical robustness, and an availability incentive in the OFTO licence has been used to ensure reliability.[29]

3.42. Theoretically there could reach a point in the future, once we have run a number of competitive tenders, where the number of parties involved creates undue complexity and coordination challenges. There is a significant role here for industry to assist with the development of robust codes and arrangements to ensure the management of the system remains economic and efficient. We think this potential risk can be managed, and will keep it under review as the tendering regime develops.

[29] The availability incentive for OFTOs is usually 98 per cent, although this varies slightly for certain projects. Total system availability for all offshore transmission systems since the first licence grant to March 2014 is over 99 per cent. https://www.ofgem.gov.uk/ofgem-publications/91890/es902offshoreoftorevenuereportweb.pdf

4. Impact assessment on interconnection, non-GB connections and multiple purpose projects

Interconnection

4.1. We have decided to extend the cap and floor approach to interconnector investment and have decided to open more application windows in future as long as efficient investment continues to be brought forward under this approach.

4.2. The cap and floor regime has already attracted significant investment interest. In December 2014 we made a final decision on the design of the cap and floor for the Nemo interconnector to Belgium,[30] which will be the first interconnector project to have a cap and floor. The first application window for the wider rollout of the cap and floor regime saw five new interconnector projects apply for a cap and floor. We have decided to award a cap and floor to the proposed 1.4GW NSN interconnector to Norway,[31] and we are also currently consulting on our minded-to position for the FAB Link, IFA2, Viking Link and Greenlink projects. We anticipate announcing decisions on these in summer 2015.[32]

4.3. We will continue to assess projects that apply for a cap and floor on their revenues through the application windows and will keep the overall approach under review.

4.4. Our aim in developing a regulatory approach to interconnectors has been to bring forward timely, economic and efficient investment where it is in the interests of existing and future consumers to do so. Supporting investment in interconnectors can provide significant benefits for consumers. Increased interconnection can reduce consumer bills by providing access to cheaper sources of electricity generation and by connecting new sources of short term balancing services. For example, we estimate that under a base case scenario the NSN interconnector will deliver benefits to GB consumers of around £3.5 billion over the 25-year cap and floor regime,[33]

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[30]Ofgem, 'Decision on the cap and floor regime for the GB-Belgium interconnector project Nemo', 2 December 2014: https://www.ofgem.gov.uk/ofgem-publications/91686/finalcapandfloorregimedesignfornemomaster-forpublication.pdf

[31] This is subject to there being no material escalation in the costs as submitted to Ofgem to date by the project developers. Ofgem, 'Decision on the Initial Project Assessment of the NSN Interconnector to Norway', 12 March 2015: https://www.ofgem.gov.uk/ofgem-publications/93855/nsndecisionletterforpublication-pdf.

[32] Ofgem, 'Cap and floor regime: Initial Project Assessment of the FAB Link, IFA2, Viking Link and Greenlink interconnectors', 6 March 2015: https://www.ofgem.gov.uk/ofgem-publications/93792/ipamarch2015consultation-final-pdf.

[33] Ofgem 'Cap and floor regime: Initial Project Assessment for the NSN Interconnector to

while our modelling for the further three interconnectors we are minded to award a cap and floor suggests that they could cumulatively increase consumer welfare by between £3 billion and £8 billion under the base case.[34] Interconnectors can also support the decarbonisation of electricity supplies by making it easier to manage intermittent renewable generation sources and locate low carbon generation where it is most efficient.

The impact of the cap and floor regime

4.5. Extending the availability of the cap and floor regime should encourage investment in interconnection (and the associated benefits discussed above) by ensuring there are clearer, upfront rules for how developers receive revenue and by reducing their risk. Under the cap and floor regime developers are still exposed to significant upside and downside due to fluctuations in revenue, which provides incentives for developers to bring forward projects that are likely to deliver benefits to consumers:

(a) *Efficient interconnection investment*: under the cap and floor approach developers are exposed to the benefits their project provides, because their revenues are mostly derived from congestion rents which are dependent on the existence of price differentials between markets at either end of the interconnector. Developers are, therefore, incentivised to invest in projects where the potential market value of interconnection is greatest. This helps to ensure that interconnectors are located in the positions that can bring benefits for consumers. We will also undertake our own assessment to ensure that it would be in consumers' interests to award a cap and floor to projects.

(b) *Efficient costs*: the cap and floor regime exposes developers to variations in revenue. This places an incentive on them to keep delivery and operation costs down, and therefore minimises the risk that consumers will have to provide any support to the interconnector owner. As part of our cap and floor assessment process, we also conduct a cost assessment exercise to ensure that costs which are potentially underwritten by a floor are efficient and justified.

Norway', 17 December 2014, p4: https://www.ofgem.gov.uk/ofgem-publications/92096/nsnipaconsultation-final-pdf.
[34] Ofgem, 'Cap and floor regime: Initial Project Assessment of the FAB Link, IFA2, Viking Link and Greenlink interconnectors', p5. The range reflects the fact that the modelling does not capture dynamic effects such as generators' responses to changes in profit levels. The lower end of the range represents the modelled impact on GB total welfare, which informs whether there are likely to be efficiency improvements in GB from building the interconnector. We think this measure indicates how these dynamic effects might ultimately affect consumers.

4.6. We believe that there is benefit to placing a floor on revenues. Without this floor, interconnector projects that are likely to offer benefits to consumers may not be brought forward due to revenue uncertainty in the longer term. The floor partially insulates the developer from this risk, but provides less consumer underwriting than a fixed revenue approach.

4.7. The cap on revenues compensates the risk that consumers are underwriting through the floor, and prevents excessive returns accruing to the developer. Any returns above the floor will be returned to consumers.

Challenges

4.8. We recognise that there are some challenges associated with the cap and floor approach. For example, developers may not take into account issues such as the investment needed to reinforce the onshore network as a result of a project. We will mitigate this risk by undertaking a detailed project assessment before awarding a revenue floor to a project. This assessment includes an evaluation of the efficiency of the connection location.

4.9. In the longer term there are risks that a developer-led cap and floor regime may not support fully efficient levels of investment in interconnection. Developers may not have incentives to invest up to the optimal level of interconnector capacity (eg if consumer benefits, such as security of supply, are not fully internalised in developers' potential revenues).

Alternative options

4.10. On balance, however, we do not think that the challenges identified above outweigh the likely benefits of taking forward this regime. We have previously set out our consideration of alternative options.[35] We have retained the option for developers to bring projects through the existing exemption route, and will consider exemptions on a case-by-case basis.

4.11. Looking at the alternative of a developer-led approach combined with a fully-regulated approach (ie fixed regulated returns), we do not consider developers would be incentivised to only bring forward good projects, as they would not be subject to the same financial exposure as under the cap and floor regime.

4.12. We also considered the potential for centrally-identified interconnection, but consider that this would take some time to implement, leading to a potential delay in investment, which could mean that consumers miss out on potential benefits of more interconnection. We also identified in our draft conclusions that under a centrally

[35] Ofgem, 'Decision to roll out a cap and floor regime to near-term electricity interconnectors', 6 August 2014: https://www.ofgem.gov.uk/ofgem-publications/89209/decisioncapandfloorneartermelectricityinterconnectors.pdf

identified approach there is a higher risk that inefficient projects could be developed, as the parties determining whether to invest would have less exposure if a project turned out to be less beneficial than originally assumed. We consider that a developer-led approach is more beneficial as long as efficient investments are enabled by this approach.

4.13. In addition to the possible alternative approaches above, another option could involve measures to create additional payment flows to reflect the costs and services provided by interconnectors within the cap and floor framework. We will continue to keep the details of the policy under review, and amend as needed, to ensure there is an appropriate framework for efficient investment in interconnection.

Non-GB connections

4.14. We have decided to adopt a default approach that non-GB connections do not receive consumer underwriting. We are willing, however, to consider on a case-by-case basis whether consumer underwriting might be in the interests of GB consumers. The benefit of this approach is that (a) potential non-GB generators have clarity over our default approach to these projects and (b) consumers are protected from undue risks. These risks are set out below.

4.15. Uncertainties in the arrangements governing the connection of non-GB generators to the GB transmission system mean that consumers would be exposed to risks if they were to underwrite these connections by default. In GB, there are clear arrangements for recovering appropriate transmission costs from generators under the connection and use of system code (CUSC), through charging and requirements for financial securities. These do not automatically apply to generators located outside GB. They would not be licensed in GB, nor be signatories to our codes and so would face different obligations. They could also be affected by changes that the non-GB authorities make to laws and regulations in their territory, which could increase the chance that the transmission assets could be stranded. Our decision protects consumers from exposure to undue risks arising from underwriting the non-GB connections – it avoids committing to one element of the transmission regulation before we are sure of the future arrangements applicable to non-GB generators.

4.16. The second key risk avoided through our decision is that if we were to make a default route for GB consumer underwriting available, non-GB generators could have an unfair advantage over GB generators. This would occur as they might not face equivalent transmission charges or other requirements. This could create bias in the wholesale market and potentially in auctions for contracts for difference (CfDs) if the UK government decides that non-GB generators can compete against GB generators for them. Non-GB projects with higher combined generation and transmission costs might be taken forward at the expense of cheaper GB projects, meaning higher costs for consumers.

4.17. The potential downsides of our default position relate to the costs faced by the non-GB generator and knock-on effect on their competitiveness and the viability of their business plans. We are open to discussions with project developers and the relevant parties in other countries to consider to what extent it is possible to ensure a level playing field overall.

Multiple Purpose Projects

4.18. We have decided that we will maintain continuity in the regulatory treatment of an existing asset if it evolves into a multiple purpose project (MPP) and work with relevant parties to developer the most appropriate treatment of projects that are MPPs from the outset.

4.19. This decision will give clarity to developers and the owners of existing assets, and, by removing regulatory barriers and creating certainty, will help to enable MPPs where they are in the interests of consumers.

4.20. There could be significant benefits to making coordinated, integrated investment in an MPP rather than in a series of separate pieces of infrastructure. We think it is important that proposals for economic and efficient investment in MPPs should be enabled.

4.21. Investment in MPPs could result in lower transmission charges because creating an MPP to fulfil multiple functions could be a more efficient way of making investments than if each individual need were to be met through a separate transmission project. Reduced transmission charges would have direct benefits for consumers and may also encourage investment in (a) low carbon electricity generation, leading to reduced carbon emissions and (b) interconnectors to other countries, bringing benefits to consumers through lower bills than would be the case otherwise and improved security of supply.

4.22. We recognise that this is not a full solution to the challenges posed by MPPs, but we think that it is proportionate to the future pipeline of possible MPPs. New projects will still need to be evaluated as they arise, while a range of detailed commercial and regulatory issues will need to be resolved before an MPP is formed.

Different groups, geographic distributional impact and strategic and sustainability considerations

Consumers

4.23. Consumers will benefit from these decisions. The increased investment in interconnectors enabled by the rollout of the cap and floor regime will bring benefits for consumers through reduced prices of electricity and greater security of supply.

4.24. Consumers' interests will be protected by our default position on consumer underwriting for non-GB connections, in that they will not be asked to take on the risk of supporting transmission projects without knowing what the charging and other regulatory arrangements applicable to non-GB generators are now or may be in the future. In some cases consumers may be able to benefit from lower cost and lower carbon non-GB generation. We are open to discussing the regulatory arrangements of the non-GB connection on a case-by-case basis so that, where consumers' interests are protected, these benefits can be unlocked.

4.25. Our decision on MPPs may benefit consumers by enabling investment in MPPs where they are an efficient way of meeting several needs. This could result in lower prices than would have otherwise resulted if each investment was delivered separately.

Industry participants

4.26. Our decision to continue the cap and floor regime gives regulatory certainty to interconnector developers. Developers of potential non-GB generation projects will also benefit from the clarity provided over the default position on consumer underwriting for the transmission connection from their project to the national electricity transmission system (NETS). However, if non-GB connections are not given a regulated revenue they will (a) face a higher cost of capital for the connection relative to a scenario in which there is consumer underwriting, and (b) have to pay for the full cost of the transmission that would connect them to the GB transmission network. If the UK government decides that non-GB generators should compete against GB generators in CfD auctions, facing a different risk profile on the transmission connection could affect the relative position of those generators compared to GB generators in CfD auctions. However, consumer underwriting cannot be considered in isolation from the rest of the regulatory arrangements faced by the generators, and issues like user commitment and charging arrangements will also determine the relative advantage or disadvantage of generators in different jurisdictions.

4.27. TOs and interconnector developers will benefit from increased certainty as a result of our decision on MPPs, reducing the risk they face in investing in an asset where there is a possibility that it could evolve into an MPP later. Generators seeking to invest in generating stations that could connect to an existing asset could also benefit from reduced transmission charges if they are able to connect to an MPP rather than a separate transmission connection.

Geographic distribution considerations

4.28. As noted above, our default position on non-GB connections means that, if the UK government decides that they are able to compete with GB generators in CfD auctions, non-GB generators may face a different risk profile on the transmission connection than GB generators. We will evaluate the arrangements for non-GB connections on a case-by-case basis and are open to discussing the arrangements with the relevant parties to ensure, wherever possible, a level playing field.

Strategic and sustainability considerations

4.29. Greater interconnector capacity will bring strategic benefits to GB through increased security of supply and resilience. If investments are made in MPPs that include connections to other countries, then there will also be security of supply benefits.

4.30. Our default position that non-GB connections should not receive consumer underwriting protects consumers from taking on a long term risk when we cannot be sure that the appropriate regulatory arrangements are in place to manage the risk. This position may have an impact on the ability of GB consumers to benefit from low carbon generation in non-GB territories. However, if they are allowed to participate in CfD auctions, non-GB generators are likely to be competing with other low carbon generators so the net impact on the carbonisation of the electricity sector may be small. We will also have the flexibility to consider whether there would be benefits to providing consumer underwriting on a case-by-case basis.

4.31. Our decision to provide regulatory certainty for the licensees of existing transmission assets may enable MPPs to be created where they are efficient. This in turn may decrease the cost of investment in renewable generation and encourage an increase in the level of renewables in the electricity mix.