Title: Extending competitive tendering in the GB electricity network **IA No:** TBC **RPC Reference No:** **RPC-4464(1)-BEIS** **Lead department or agency:** BEIS **Other departments or agencies:** Ofgem	Impact Assessment (IA) **Date:** 05/07/2021 **Stage:** Consultation **Source of intervention:** Domestic **Type of measure:** Primary legislation **Contact for enquiries:** Rachel.Siddell@beis.gov.uk and Daniel.Zwolinski@beis.gov.uk
Summary: Intervention and Options	**RPC Opinion:** GREEN

Cost of Preferred (or more likely) Option (in 2019 prices, 2019 Present Value terms)			
Total Net Present Social Value	**Business Net Present Value**	**Net cost to business per year**	**Business Impact Target Status**
N/A	N/A	£5.8m	Qualifying provision

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

In the coming years, significant investment will be needed in the electricity network to support the increased electricity demand and renewable generation needed to meet our Carbon Budget targets and achieve Net Zero, in a way that is secure, sustainable, affordable and value for money for consumers. In 2019, approximately a fifth to a quarter of a typical household electricity bill was made up of the cost of transporting electricity from the place that it was generated to the customer.[1] It is imperative that Government looks for opportunities to bear down on these costs and reduce those being passed through to consumers.

In 2009, Government introduced legislation that enables the Office of the Gas and Electricity Market Authority (Ofgem) to run a competitive process to identify the party that owns and operates electricity transmission infrastructure that connects offshore generators like windfarms to the mainland. The regime has proved a success and has brought estimated savings for consumers in excess of £800 million since 2009.[2,3]

The Government is planning to extend this competitive regime to the onshore electricity network. Introducing a competitive tender process would enable new parties to enter the market, address the information asymmetry that exists between Ofgem and the network companies it regulates and introduce for the first time direct, in-the-market competitive pressure on capital and operational expenditure on large onshore electricity network infrastructure. Government intervention is necessary because the establishment of this regime requires primary legislation.

This IA assumes that competed assets are connected at the transmission level and operated by Transmission Operators (TOs), however, the primary legislation will cover the onshore network as a whole, and will therefore also allow for assets that are connected at the distribution level to be completed and operated by Distribution Network Operators (DNOs). However, due to a lack of data on the number and value of distribution network connected assets that meet the criteria for competition, this IA does not attempt to assess the costs and benefits of extending competition to distribution network connected assets. Similarly, the legislation will allow for competition to be between network assets and solutions which require a contract for implementation (as opposed to a licence). Only Transmission-connected licensable assets are considered in this Impact Assessment due to available data and the policy position being that competition will likely be introduced for transmission-connected large assets to begin with, as alternative solutions become market-ready to be competitive with traditional solutions.

[1] https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill. Estimate based on an average electricity bill for a typical domestic customer of the six large suppliers.

[2] https://www.ofgem.gov.uk/publications-and-updates/consultation-cepabdo-evaluation-offshore-transmission-tender-round-1-benefits

[3] 2018/19 prices. Original figure of £770 million (2014/15 prices) consists of the lower range (conservative) estimate of total savings for TR1, TR2 & TR3 for counterfactual #3 and can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

What are the policy objectives of the action or intervention and the intended effects?

The primary policy objective is to extend competitive tendering to areas of the onshore electricity network where it is efficient and cost-effective to do so, thereby bearing down on the cost of network investment to limit the costs being passed through to consumers.

Based on the experience of the offshore competition regime and taking into account tender costs incurred by Ofgem, Government estimates that the introduction of this system could, in a medium scenario, provide overall net estimated savings in the range of **£300m - £500m** (2019 prices, PV over 32 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset, allowing for scheme setup and asset construction). This is a conservative estimate of the possible benefits – in reality, the net benefits from introducing competition could be significantly higher than this, especially if many large-scale electricity transmission projects are brought forward earlier in the wake of Government's recently announced commitment to reducing carbon emissions to 78% of 1990 levels by 2035.

In addition, competition will help bring on new technological solutions, financial innovation and more investment in research and development. It should also encourage new players into the market and drive up performance. It could also help identify innovative, significantly cheaper, alternatives to current network solutions put forward by regional monopoly operators, for example non-build 'market' solutions instead of traditional 'asset-build' solutions.

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

Four options were considered in this IA:

Do Nothing: The status quo remains in place: all onshore network assets continue to be built by the 'incumbent' or 'monopoly' owners of the networks in their respective regions.

Alternative 'Do Nothing Option': The status quo remains in place: all onshore network assets continue to be built by the 'incumbent' or 'monopoly' owners of the networks in their respective regions. However, using existing powers, Ofgem could award licences for the construction and operation of onshore network assets without corresponding primary legislation. In order to achieve benefits associated with competition, Ofgem has already considered alternative ways in which it could introduce competition (and/or replicate its effects) under its current powers i.e. the Competition Proxy model (CPM) and Special Purpose Vehicle (SPV) model. In the case of the CPM, it was considered that this would not bring the benefits of true competition, as monopolies remain, and so costs are estimated by benchmarking against other network companies alone. In the case of the SPV model the full benefits of competition are more difficult to achieve due to the need for the monopoly provider to run the competition and contract with the winning bidder. This risks sub-optimal outcomes as a result of inefficient running of the competition and/or allocation of risk. In addition, hurdles remain for third parties entering the market without legislation, so the benefits associated with new markets and businesses developing will not arise and subsequently Green Recovery aims are not contributed to by this option. Without a clear legal framework in place, investors may be less willing to come forward, weakening the level of competition and reducing the potential savings for consumers.

Policy Option: Government introduces changes to primary legislation that enable a body appointed by the Secretary of State to tender competitively licences and/or contracts for onshore electricity network assets or services where there would be a demonstrable consumer benefit from doing so, as judged by applying certain criteria to an indicative solution to solve the constraint in question, and for Ofgem to grant a relevant licence to the successful bidder. The initial expectation is to extend competition to new, high value and separable onshore electricity transmission network solutions. The changes to primary legislation will also allow for competition of licences and/or contracts relating to the onshore electricity **distribution** network. Government will ensure sufficient flexibility within the legislation to extend competition to distribution level in the future if this is in the interest of consumers. <u>This is the preferred option</u>.

Alternative 'Policy Option': Government could introduce legislation that enables a body appointed by the Secretary of State to run tenders and award licences for the construction and operation of certain onshore network assets on a competitive basis, but mandate competition for all assets, regardless of size, newness or other criteria. Government expects this would be disproportionate and that, competitive tendering of onshore network assets will only lead to benefits for consumers in certain circumstances.

Is this measure likely to impact on international trade and investment?	TBC			
Are any of these organisations in scope?	**Micro** Yes	**Small** Yes	**Medium** Yes	**Large** Yes

What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)	**Traded:** N/A	**Non-traded:** N/A
Will the policy be reviewed? No. **If applicable, set review date:**		

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: .... Date: ....

Summary: Analysis & Evidence

Policy Option 1

Description:

FULL ECONOMIC ASSESSMENT

Price Base	PV Base	Time Period	Net Benefit (Present Value (PV)) (£m)		
2018/19	2019	32 years	**Low:** N/A	**High:** N/A	**Best Estimate:** N/A

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	N/A		N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	N/A		N/A	**N/A**

Description and scale of key monetised costs by 'main affected groups'

The expected changes to primary legislation would enable secondary legislation that would, in turn, enable a body appointed by the Secretary of State to run tenders that determine competitively the party that would be granted a licence by Ofgem to own and operate certain onshore electricity network assets or the party that would be given a contract to undertake a network solution. The primary legislation in itself would therefore not create any immediate costs: these will only take effect once the subsequent secondary legislation is in place. It is estimated that there will be costs associated with setting up the scheme and running additional tenders. While these costs are likely to be higher than the cost of regulation under 'Do Nothing', they are estimated to be outweighed by the benefits realised through competitive tendering. Under the preferred option, the body appointed by the Secretary of State to run the tenders incurs **setup costs** which it passes through to the National Grid Electricity System Operator (ESO) these are estimated to be £3m. In future some of these costs might be recouped through tender costs. The **cost of running tenders** is incurred by a body appointed by Secretary of State and passed through to the successful bidder. In the first instance, this cost is estimated to be between £0-£65m (PV of costs over 32 years). Successful incumbent transmission operators (TOs) or new entrants incur **bid costs**, which Government estimates to be between £0-£150m (PV of costs over 32 years). Based on the offshore experience, set-up, tender and bid costs (of successful bidders) are assumed to be passed through to generators / suppliers and ultimately end-consumers. The bid costs of unsuccessful bidders are assumed to remain with them; although these can be proxied using anecdotal data on total investment, this data is of insufficient quality to be used in an official assessment. Therefore, the bid costs of unsuccessful bidders have not been quantified. Additionally, the Electricity System Operator - that calculates Transmission Network Use of System (TNUoS) charges - will have to deal with more parties in the market. However, as the system operator (SO) already deals with a number of parties involved in transmission networks (three onshore TOs and a number of other operators), additional interface costs are assumed to be £0.

This IA uses Ofgem's Special Purpose Vehicle (SPV) model to quantify the range of possible benefits from opening the construction of eligible network assets or other solutions to competition. The SPV model assumes that the tender would be run by the incumbent TO. Due to the associated incentive risks, the model includes a sensitivity whereby construction costs can **increase** by up to 10% due to inefficient implementation by the incumbent. This IA assumes that tenders would be run by an independent party which is incentivised to ensure a successful and efficient tender – this would be expected to reduce the risk of an increase in construction costs compared to the SPV model. However, the sensitivity around construction costs is kept in this IA due to the relative dearth of real-world data on the benefits of Ofgem's SPV model. In the worst-case, analysis shows that a poorly designed competition can **increase the total construction costs** of tendered assets by up to **£200m** (PV of costs over 32 years, with an assumed 10-year investment period) in the scenario with the largest pipeline of eligible assets (Scenario 5). This cost is assumed to pass through to end-consumers – however, it is important to note that a poorly designed competition only serves to reduce the total net benefit to society and will not manifest as an additional cost to businesses in any scenario. This is because increased asset costs imply increased regulated revenue streams, which keeps the return on assets for business (all incumbent TOs and new entrants) the same as under 'Do Nothing'. The additional construction costs end up being passed down to end-consumers as part of increased network charges via the allowed revenue system.

Other key non-monetised costs by 'main affected groups'

Competitive tendering would enable any successful bidder to deliver the construction or operation of selected assets or other network solutions, which may lead to new parties entering the market should they be the successful bidder. In this scenario, the incumbent TO would no longer deliver that asset and would forego return on this investment; instead, the new entrant would incur the asset/network solution costs, which would ultimately be a gain as they will earn a return on this investment. These effects have not been separately quantified for the incumbent TOs and new entrants as they depend on the success rates of either group during a competitive tender (potential upper bounds are set out in the supporting evidence).

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	N/A		N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	N/A		N/A	**N/A**

Description and scale of key monetised benefits by 'main affected groups'

The expected changes to primary legislation would enable secondary legislation that would in turn enable the competitive tendering of onshore transmission licences. The primary legislation in itself would, therefore, not create any immediate benefits; these can only be realised once the relevant secondary legislation is in place. The overall monetised benefit to society associated with extending competitive tendering is the cost saving associated with increased competition, which is likely to be more effective in a range of circumstances in revealing the true and more efficient costs of TOs than through the price control process. In terms of any benefits to the group of incumbent TOs and new entrants, this IA assumes, for simplicity, that returns on investment are unchanged between 'Do Nothing' and the 'Policy Option'. Caveats around this assumption are set out in the supporting evidence. The ultimate quantified benefits of cost savings are felt by consumers.

Extending competition to the onshore electricity network is expected to deliver savings to consumers, which analysis shows will range between **£0-£1.2bn** depending on the scenario. According to Government's central scenario (pipeline scenario 3), this intervention will deliver a net benefit to consumers of between **£300m - £500m** (PV over 32 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset, allowing for scheme setup and asset construction).

This will be achieved via a reduction in the **operating** and **construction** costs of eligible assets. Based on the operating cost savings from the offshore experience, this IA estimates that **operating** cost savings alone will range between **£0-£1bn** (PV over 32 years, relating to assets tendered over the next 10 years, with benefits considered over 20 years for each asset, allowing for scheme setup and asset construction) across scenarios. Extending competition to the onshore electricity network is also likely to lead to non-negligible financing cost savings – however, estimating this element is difficult as a result of the very different risk profiles that bidders will face by taking on additional construction risks. Given these uncertainties, there is a large margin for error for calculating the potential financing cost savings; therefore, this IA does not attempt to quantify this benefit.

Construction cost savings have been estimated using Ofgem's SPV model, which assumes that construction costs of tendered assets can decrease by up to 10% in an efficiently run competition – though the model also stipulates that a poorly run competition can **increase** construction cost by up to 10% in the worst-case scenario. The analysis shows that construction costs savings are estimated to amount **up to £200m** (PV of costs over 32 years, with an assumed 10-year investment period) in the scenario with the largest pipeline of eligible network assets (Scenario 5) with an efficiently run competition.

Other key non-monetised benefits by 'main affected groups'

Introducing competition can bring many wider non-monetised long-term innovation benefits to society beyond the monetised reduced cost of investment in assets over time. These include new technological solutions being brought forward and more investment in research and development. These will in turn drive costs down in the long run for the industry overall. Reduced barriers to entry will mean that new parties may enter the market, while incumbent TOs will incur lower transmission asset costs (either due to not being appointed as the successful bidder or due to experiencing more efficient costs through competitive pressures). These effects have not been separately quantified for incumbents and new entrants as they depend on the success rates of either group during competitive tendering. Furthermore, there are also benefits due to reduced costs of price control regulation for Ofgem and incumbent TOs. However, Ofgem has advised that it is not possible to estimate these costs in isolation.

Key assumptions/sensitivities/risks	Discount rate (%)	3.5%

A full list and detailed explanation of assumptions underpinning the monetised costs and benefits, risks and sensitivity analysis is included in the main body of this IA in the 'Assumptions and Risks' section.

Key assumptions for quantifications include:

- 3.5% discount rate, discounted to 2019.
- **2018/19 price base**: unless stated otherwise, all prices in this IA are quoted using the 2018/19 price base. To avoid any confusion resulting from the large number of different sources using varying price bases, all prices quoted in this IA have been converted to a 2018/19 price base, where possible. The original figures have been included in the footnotes for ease of sourcing.
- There is no end date to the proposed 'Policy Option'. Therefore, the IA assumes that assets are tendered over the next 10 years, with benefits considered over 20 years for each asset.
- This IA assumes that setting up the scheme will take at least 2 years, tendering will take at least 1 year, and construction will take up to 3 years per asset. Asset operation is therefore assumed to start in the 7th year.
- Pipeline scenarios of eligible projects in the future are approximated by considering historic information on Transmission Investment for Renewable Generation (TIRG) and the Transmission Investment Incentives (TII) framework over the Transmission Price Control Review 4 (TPCR4) from 2007/08 to 2012/13. The pipeline scenarios also reflect the levels of investment that has occurred over the RIIO-T1 (via the Strategic Wider Works (SWW) investment mechanism) and ED1 price control regimes.
- The pipeline scenarios assume that a set of criteria will be adopted that will identify the assets suitable for tendering. The best available information at the time of writing this IA, in line with Ofgem's Integrated Transmission Planning and Regulation (ITPR) final conclusions[1], is that these assets will be new, high-value (i.e. over £100m expected capital value), and separable.
- Tender costs are based on a 1% of asset value, which is an Ofgem estimate based on the offshore experience.
- Bid costs of successful bidders (which include preparing bids for evaluation, reaching the licence grant and acquiring the asset) are assumed to be 2.4% of asset value and are based on the 'Evaluation of OFTO Tender Round 2 and 3 Benefits' report by Cambridge Economic Policy Associates (CEPA) and on internal discussions with Ofgem. Bid costs of unsuccessful bidders (which only refer to the preparing of bids for evaluation) have not been quantified.
- The operating cost percentage savings experienced in the offshore regime and the price control counterfactual, as set out in the CEPA report, have been applied to asset values in this IA.
- Two different versions of the operating cost pathways are used: a "<u>central</u>" set and a "<u>pessimistic</u>" set. The lower starting premium of the "<u>pessimistic</u>" is supposed to reflect the (extremely unlikely) scenario where all assets in the pipeline are of the smallest possible size that is expected to be eligible for competition (valued at £100m), which could limit the range of possible operating cost savings. **Government believes that the inclusion of the 'pessimistic' pathways for Opex in the range of results risks significantly understating the benefit to society** that can be gained from increased competition. Therefore, only the "<u>central</u>" set of pathways are used to derive the final cost saving figures in this IA; the "<u>pessimistic</u>" set is only used as a sensitivity to test the robustness of the results.
- Finance cost percentage savings have not been quantified as part of this IA.
- The CEPA report points out that there are limits to the extent to which lessons for the onshore network can be drawn from results in the offshore network whilst also asserting the OFTO approach offers lessons for structuring other contestable infrastructure opportunities. Results in the offshore network, for example, are context and time-specific, and there are real-world, technological differences between on- and offshore transmission assets. However, while savings in the onshore network are likely to be driven by different factors, Government believes that it is reasonable to assume that the overall levels of saving in operational expenditure under competition will be comparable across the onshore and offshore regimes.

This IA assumes that competed assets are connected at the **transmission level** and operated by Transmission Operators (TOs). However, primary legislation is expected to cover the onshore network as a whole and will therefore also allow for competition for network assets that are connected at the **distribution level** (and thus operated by Distribution Network Operators, DNOs). However, due to a lack of data on the number and value of distribution network connected assets that meet the criteria for competition, this IA does not attempt to assess the costs and benefits of extending competition to distribution network connected assets.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			Score for Business Impact Target (qualifying provisions only) £m:
Costs: £5.8m	**Benefits: £0**	**Net: -£5.8**	TBC

[1] Ofgem, 'RIIO-2 Sector Specific Methodology – Core Document', published May 2019, https://www.ofgem.gov.uk/system/files/docs/2019/05/riio-2_sector_specific_methodology_decision_-_core_30.5.19.pdf, pp. 89 & 91.

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Results of the Cost Benefit Analysis of the proposed intervention

Net Cost / Benefit Estimates: 'Policy Option' vs 'Do Nothing' option

1. This section presents the key findings of the full cost benefit analysis of the proposed policy intervention (the 'Policy Option' versus the 'Do Nothing' option). A brief summary of the methodology used to derive these estimates is provided below. For a more detailed overview of the underlying assumptions and their associated risks, please refer to the '*Monetised and non-monetised costs and benefits of each option*' section of this IA (pp. 26-51).
2. These costs and benefits are classified as **direct impacts at the secondary legislation stage** as they are expected to result directly from the implementation of secondary legislation.
3. The GB onshore network consists of both high voltage electricity transmission and lower voltage distribution systems. The proposed changes to primary legislation will cover the entire onshore network, both transmission and distribution. However, this IA **only captures assets are connected at the transmission level** and operated by Transmission Operators (TOs) and does not include assets that are connected at the distribution level and operated by Distribution Network Operators (DNOs). This is for two reasons:
    a) Distribution connected assets tend to be smaller in size/value and therefore there is some uncertainty as to how the "high value" would be defined if this were used as a criterion – at the transmission level the expectation is that this would be defined as being over £100m in expected capital value and it is anticipated that indicative solutions to constraints at hand would need to meet this and two other requirements to be eligible for tendering – the other two being that assets need to be "new" and "separable"; and
    b) There is a general lack of readily available data that could be used to accurately estimate the number and total value of distribution network connected assets that meet the expected criteria for competition.
4. Therefore, this IA quantifies the expected net benefit from extending competition to the GB **transmission network only**. In doing so, this IA is very likely underestimating the overall net benefit to society from this intervention. Distribution network impacts will be quantified if the Secretary of State considers it appropriate to include distribution assets in regulations setting criteria for assets to be subject to competition.
5. The focus of this IA is to quantify the benefits of competing out licensed transmission-level assets. In doing so, it omits the potential benefits of introducing contracted out services and flexible network solutions on both the transmission and distribution level. This reflects the policy position that competition will most likely be introduced for transmission-connected large assets to begin with, as alternative solutions become market-ready to be competitive with traditional solutions. In effect, this means that this IA potentially underestimates the overall benefits that could materialise from the introduction of competition in the electricity networks sector.
6. The quantifications presented here **are approximations and ranges of potential costs and benefits**. They are intended to provide a sense of scale rather than precise costs and benefits which Government expects from competition. It is inherently difficult to predict with any accuracy the potential efficiency benefits that introducing a competitive process might bring, given the many uncertainties around the project pipeline, and the fact that examples of the use of competition in transmission delivery are context specific. It is also difficult to quantify meaningfully the dynamic benefits of competition, such as the scope for increased innovation and the introduction of new products, services and technologies.
7. The creation of a new competition regime for GB's onshore electricity network is expected to lead to a significant net benefit to society, through cost savings that will eventually be passed

down to consumers. This IA quantifies **two types of benefits** that are expected to materialise under increased competition:

a) Lower operating costs (or 'operating/Opex cost savings'); and

b) Lower construction costs (or 'construction/capital/Capex cost savings'). These lower costs are assumed to materialise if the competition regime is set up and managed well. However, this IA explicitly factors in the risk that **a poorly managed competition may in fact lead to increased construction costs** versus the price control counterfactual.

8. As well as quantifying two distinct types of benefit, the new competition regime will entail some administrative costs that will also be passed down to consumers. For the purposes of this IA, **four types of costs** were quantified:

a) Set-up costs – the one-off costs associated with creating the competitive regime;

b) Tender costs – the costs associated with running a particular competitive tender;

c) Bid costs – the costs of bidding into a particular competitive tender; and

d) Increased construction costs – this is a special cost that materialises only in the (very unlikely) event of a **poorly managed competition** regime. If the regime is managed well, it is expected that overall construction/capital costs will decrease. If it is managed moderately well, there is no change to the overall construction costs of tendered assets.

9. Much of this IA relies on the findings from the offshore transmission asset experience, assessed in the CEPA report on Tender Rounds 2 and 3 of Ofgem's offshore transmission owners ('OFTO') licensing regime[1]. The expected benefits to society from increased competition in the GB onshore network are estimated against **a price control counterfactual** from the CEPA report where the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime. In the CEPA report, this is outlined as "Counterfactual 3", and is the most comparable counterfactual to the 'Do Nothing' option, as well as being the conservative counterfactual.

Methodology: estimating operating (Opex) cost savings

10. The IA's approach to quantifying operating cost savings is based around applying a set of possible operating cost savings pathways to a pipeline of network assets. These pipelines are supposed to represent the total value of future onshore network assets/investments that would meet the expected eligibility criteria for competition – a total of 5 pipeline scenarios are considered, reflecting uncertainty around both the size of future investment in the GB onshore network and the nature of the assets in that pipeline – i.e. whether they will meet the expected eligibility criteria for competition. More detail on the pipeline scenarios and how they were derived can be found in the '*Monetised and non-monetised costs and benefits of each option*' section of this IA (pp. 26-49).

11. The IA uses a set of operating cost 'pathways' (derived from the CEPA report on Tender Rounds 2 and 3) to estimate the range of possible operating cost savings that would be expected to materialise under increased competition.

12. The basic premise behind these 'pathways' is that **there is uncertainty regarding the effectiveness of future price discovery by the regulator** (Ofgem, via its periodic regulated price controls) and its ability to drive down incumbent costs towards the 'true' market value under the 'Do Nothing' counterfactual:

a) Pathway 5 represents the most 'optimistic' version of the counterfactual, where Ofgem is relatively efficient at discovering the 'true' market price of operating the new asset

[1] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

via its regulatory toolkit, and thus manages to force the incumbent operator to decrease their overall operating costs through successive price control reviews. The regulator eventually succeeds in eliminating all operating costs in excess of the 'true' market value by the end of the lifetime of the asset – i.e. after four successive price control periods (which are assumed to last 5 years for simplicity).

b) Pathway 4 represents a slightly more pessimistic version of the counterfactual, where Ofgem is able to gradually decrease the excess operating cost of the asset, but there still remains a small difference ('premium') versus the true market value by the end of the lifetime of the asset due to less efficient price discovery.

c) Pathway 6 represents the most pessimistic version of the counterfactual, where Ofgem is inefficient at price discovery and is unable to force the incumbent operator into reducing excess operating costs at all.

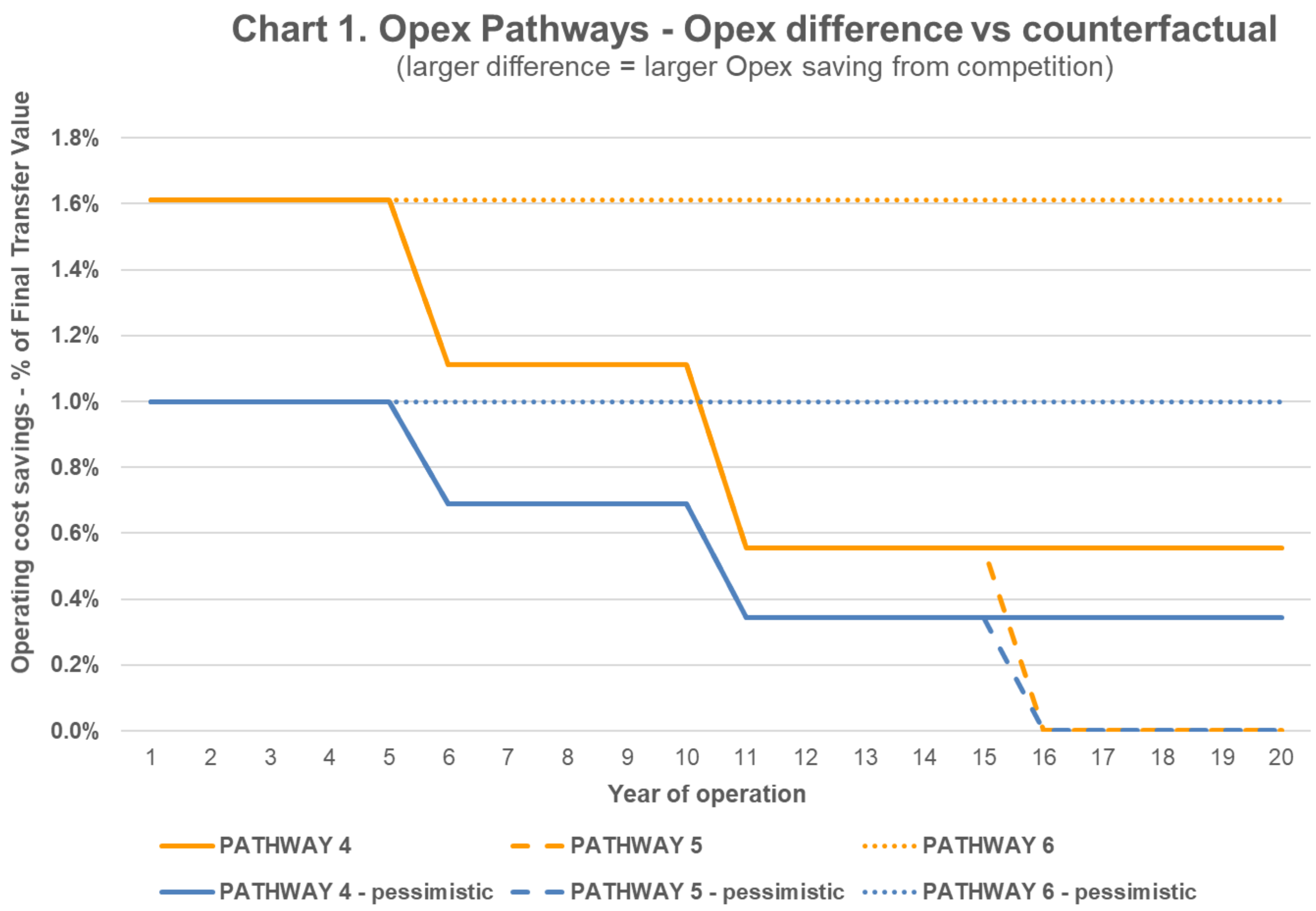
13. **Two different versions of the above three operating cost pathways are used** (see tables 9 and 10): a "central" set and a "pessimistic" set. The "central" set (**pathways 4 – 6**, shown in Chart 1 below, **orange lines**) have been derived from the CEPA report on OFTO Tender Rounds 2 and 3. The "pessimistic" set (also shown in Chart 1 below, **blue lines**) are constructed in the same way as pathways 4 – 6, but have a lower starting premium. This lower starting premium is supposed to reflect the (extremely unlikely) scenario where all assets in the pipeline are of the smallest possible size that is expected to be eligible for competition (valued at **£100m**), which could limit the range of possible operating cost savings. This is based on the finding by Frontier Economics that operating cost savings are dependent on asset size and can be as low as **1%** of the value of the asset.[2] It is important to note however that such a scenario is extremely unlikely – large-scale transmission projects are often worth many hundreds of millions of pounds.

14. For each set of pathways, the mean 'premium' is taken from all three pathways in each year. This mean value is then applied to the relevant asset pipeline scenario to calculate the mean expected operating cost saving for that year. This is repeated for every year of operation (this IA assumes a 20-year operating lifetime per project).

15. Chart 1 below shows the expected operating cost **premia** vs the price control counterfactual for each pathway group. If a pathway reaches 0%, this means that its operating costs are identical to those under the price control counterfactual (which is equivalent to 'Do Nothing'). Therefore, the higher the premium, the higher the positive difference (i.e. benefit) vs the price control counterfactual scenario.

16. Due to the extreme nature of their underlying assumptions, the "pessimistic" pathways are not used to derive the estimates of operating cost savings presented in this IA. **Only the "central" set of pathways are used.** The "pessimistic" pathways are only applied as a sensitivity to test the robustness of the Opex savings estimates.

[2] Frontier Economics, 'A cost benefit analysis of the potential introduction of competitively appointed transmission operators', published January 2016, https://www.ofgem.gov.uk/ofgem-publications/98418/ngresponseappendix2fronteireconomicsrpt-catocba-080116-final-pdf, p. 53



Methodology: estimating construction (Capex) cost savings

17. To estimate capital savings, we use evidence from Ofgem's SPV model. Analysis conducted by Ofgem assumes construction cost savings can amount to **10%** of the value of the asset for an efficiently run competition.[3] The SPV model assumes that the tender would be run by the incumbent TO. Due to the associated incentive risks, the model includes a sensitivity whereby construction costs can increase by up to 10% due to inefficient implementation by the incumbent. This IA assumes that tenders would be run by an independent party which is incentivised to ensure a successful and efficient tender – this would be expected to reduce the risk of an increase in construction costs compared to the SPV model. However, the sensitivity around construction costs is kept in this IA due to the relative dearth of real-world data on the benefits of Ofgem's SPV model.

18. As a sensitivity, we have included two further Capex savings scenarios where the capital saving from competition is **0%** (i.e. no net benefit) and **-10%** for a poorly managed competition. This sensitivity aims to account for the increased construction risks that could be borne by new entrants versus an incumbent TO – though it must be stressed that the latter scenario (of a 10% increase in construction costs) is highly unlikely, as the tenders would be run by an independent party that is incentivised to ensure a successful and efficient tender.

[3] Ofgem, 'Hinkley-Seabank project: minded-to consultation on delivery mode', published January 2018, table 3.3, https://www.ofgem.gov.uk/ofgem-publications/127841, p. 28

Results of cost benefit analysis

19. Table 1 below summarises the estimated direct net monetised benefit to business in NPV terms across five scenarios. The scenarios demonstrate the likely scale of potential costs and benefits. Note that not all costs and benefits could be quantified (as set out in detail in the section 'Monetised and non-monetised costs and benefits of each option').

20. The quantified direct net cost to business is in the range of £3m to £216m (PV) over the appraisal period of 32 years, with a central estimate of £110m (PV). Note that while some businesses, namely TOs and new entrants, incur the direct expenditure, they will pass these costs onto other businesses, namely generators and suppliers (indirect cost), which ultimately pass them on to end-consumers, which includes business consumers (indirect cost).

21. Table 2 below presents the quantified direct net benefit to society of the proposed intervention versus a price control counterfactual ('Do Nothing' scenario). The overall net benefit to society across all 5 pipeline scenarios is in the range of **-£3m to £1.0bn** (NPV over 32 years, see Table 2).

22. The net benefit to society under the central scenario (pipeline scenario #3) is estimated to range between **£300m – £500m** (NPV over 32 years). Chart 2 below illustrates the magnitude of the various costs and benefits that could materialise depending on what scenario on construction costs (a 'well managed' vs a 'poorly managed' competition) is realised.

23. Scenario 3 represents a conservative estimate of the possible benefits – in reality, the net benefits from competition could be significantly higher, especially if many large-scale electricity transmission projects are brought forward earlier. The latter is made more likely by the Government's recently announced commitment to reducing emissions to 78% of 1990 levels by 2035[4], in line with the Committee on Climate Change's (CCC) recommendation in Carbon Budget 6.[5]

24. In order to meet these targets, significant investment in networks will be necessary. We recognise that network companies have already been taking steps towards increasing efficiencies and driving innovation when making this type of investment. However, given the scale of change that is required for net zero and the level of investment that is required, we see competition as providing a clear opportunity to further drive efficiencies and ensuring the best price for consumers.

25. All of these costs and benefits will be incurred as a consequence of secondary legislation. None of these costs or benefits relate directly to the primary legislation associated with this IA.

[4] UK Government, https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035

[5] The CCC, https://www.theccc.org.uk/publication/sixth-carbon-budget/

Table 1: Quantified Net Direct Cost/Benefit to Business, NPV over 32 years, £m, 2018/19 prices (discounted to 2019)

NPV (£2018/19m, discounted to 2019)		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Benefits	**Total quantified benefits**	**-***	**-***	**-***	**-***	**-***
Costs* **	Bid costs of appointed incumbent TOs or new entrants	£0m	£43m	£75m	£86m	£150m
	Set-up and tender costs (Ofgem/appointed body pass through)	£3m**	£21m	£34m	£39m	£66m
	Additional interface costs for the SO	£0m	£0m	£0m	£0m	£0m
	Costs due to delay risk	£0m	£0m	£0m	£0m	£0m
	Total quantified costs	**£3m**	**£64m**	**£110m**	**£125m**	**£216m**
Total cost/benefit to business		**-£3m**	**-£64m**	**-£110m**	**-£125m**	**-£216m**

* Benefits for businesses are zero as the analysis assumes that reduced asset costs imply reduced revenue streams, therefore keeping the return on assets for business (all incumbent TOs and new entrants) the same as under 'Do Nothing'. Should the competitive tender regime provide better or more stable returns, or should businesses outperform anticipated cost structures as set at the time of the tender by more than under 'Do Nothing', businesses would experience a benefit. In addition, businesses experience a benefit through lower cost of regulation under the RIIO price control (their own and the appointed body's costs decrease); however, these could not be quantified in this IA.

** In Scenario 1, the appointed body's set-up costs are fully recovered through the licence fee (paid by the ESO) (direct cost). In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost).

*** In the event that a poorly managed competition leads to increased construction costs, the additional cost will of course reduce net social welfare. However, **the additional costs for businesses as a result of a poorly designed competition will be nil**, as increased asset costs imply increased (regulated) revenue streams, which keeps the return on assets for business (all incumbent TOs and new entrants) the same as under 'Do Nothing'. The additional construction costs simply end up being passed down to end-consumers as part of increased network charges via the allowed revenue system.

Note: All estimates are rounded.

Table 2: Quantified Net Direct Cost/Benefit to Society, NPV over 32 years, £m, 2018/19 prices (discounted to 2019)

NPV (£2018/19m, discounted to 2019)		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Benefits *	Consumer cost savings	£0m	£220-330m	£380-580m	£440-660m	£760-1,160m
	Total quantified benefits	**£0m**	**£220-330m**	**£380-580m**	**£440-660m**	**£760-1,160m**
Costs	Bid costs of appointed incumbent TOs or new entrants	£0m	£43m	£75m	£86m	£150m
	Set-up and tender costs	£3m	£21m	£34m	£39m	£66m
	Costs due to delay risk	£0m	£0m	£0m	£0m	£0m
	Additional interface costs for the SO	£0m	£0m	£0m	£0m	£0m
	Total quantified costs	**£3m**	**£64m**	**£110m**	**£125m**	**£216m**
Total cost/benefit to society*		**-£3m**	**£160-270m**	**£270-470m**	**£310-540m**	**£550-940m**

Note: All estimates are rounded.
*The uncertainty around construction cost savings means that the consumer cost savings and thus benefits to society need to be shown as a range of possible values. The range of benefits is based on the estimated operating cost savings (based on pathways 4-6) and the three modelled construction cost (capex) savings scenarios assumed under the SPV. The lower value of a range shows the net benefit to society assuming a poorly managed competition that leads to increased capital costs (-10% capex saving), while the upper range assumes an efficiently run competition that leads to significant reductions in capital costs (10% capex saving).

26. Government believes that the inclusion of the 'pessimistic' pathways in the range of results risks significantly understating the benefit to society that can be gained from increased competition. The estimates presented in this IA include several other sensitivities that already factor in optimism bias – i.e. the use of CEPA's pathways 4-6 instead of the more optimistic pathways 1-3 and the inclusion of a scenario where asset construction costs increase by 10% as a result of a poorly designed competition. The latter scenario is very unlikely to materialise, but it is necessary to include due to the lack of concrete data on construction cost savings. The data on operating cost savings on the other hand is much more robust as it is based on extensive data and analysis of the OFTO experience.

27. As an illustration, the use of the 'pessimistic' pathways reduces the lower bound of the net benefit to society under the central scenario (pipeline scenario #3) by ~£200m – from a range of **£300m – £500m** down to **£100m – £500m**. In the very unlikely event that all tendered assets are no larger than **~£100m** in value, the associated operating cost savings – though much reduced compared to the central case – still result in a large net benefit to consumers, to the tune of hundreds of millions of pounds (see chart 4).

28. Charts 3 and 4 illustrate the range of benefits to society across all 5 pipeline scenarios. Chart 3 shows the size of the total savings using the central operating cost assumptions (pathways 4-6, central case), while chart 4 uses the 'pessimistic' versions of pathways 4-6. It is clear that the overall benefit to society from increased competition in onshore networks will be very substantial in all but one pipeline scenario even in the event of pessimistic scenarios materialising.

29. Table 3 below presents the range of possible savings per project that are likely to materialise under the 'Policy Option.' Our analysis shows that the introduction of competition in the onshore network is expected to yield savings to the tune of **9% – 16%** per project over a 20-year period. This range includes operating cost savings only. With the addition of construction costs, we expect to see **7% – 19%** savings on a per project basis. The lower bound of the latter range represents the unlikely scenario where construction costs are 10% higher than under 'Do Nothing' due to a poorly managed competition.

Table 3: Range of expected savings from increased competition depending on pathway and scenario, on a per project basis

	Capex savings scenario		
	Poorly managed competition (-10%)	No net Benefit (0%)	Efficiently run competition (10%)
Pathway 4	8%	11%	13%
Pathway 5	7%	9%	12%
Pathway 6	14%	16%	19%
Pathway 4 - pessimistic	4%	7%	9%
Pathway 5 - pessimistic	3%	6%	8%
Pathway 6 - pessimistic	8%	10%	13%

Notes: 1. These use NPV savings figures over a **20-year** period of operation per project. This IA assumes a project lifetime of 20 years.
2. These don't include any costs associated with the tendering or bidding process (which aren't very meaningful in a per project basis on account of their small relative size – about 0.5-2.4% of asset Capex per project).

Chart 3. Pipeline scenarios 1-5: Opex CENTRAL CASE
range of estimated benefits (NPV over 32 years)

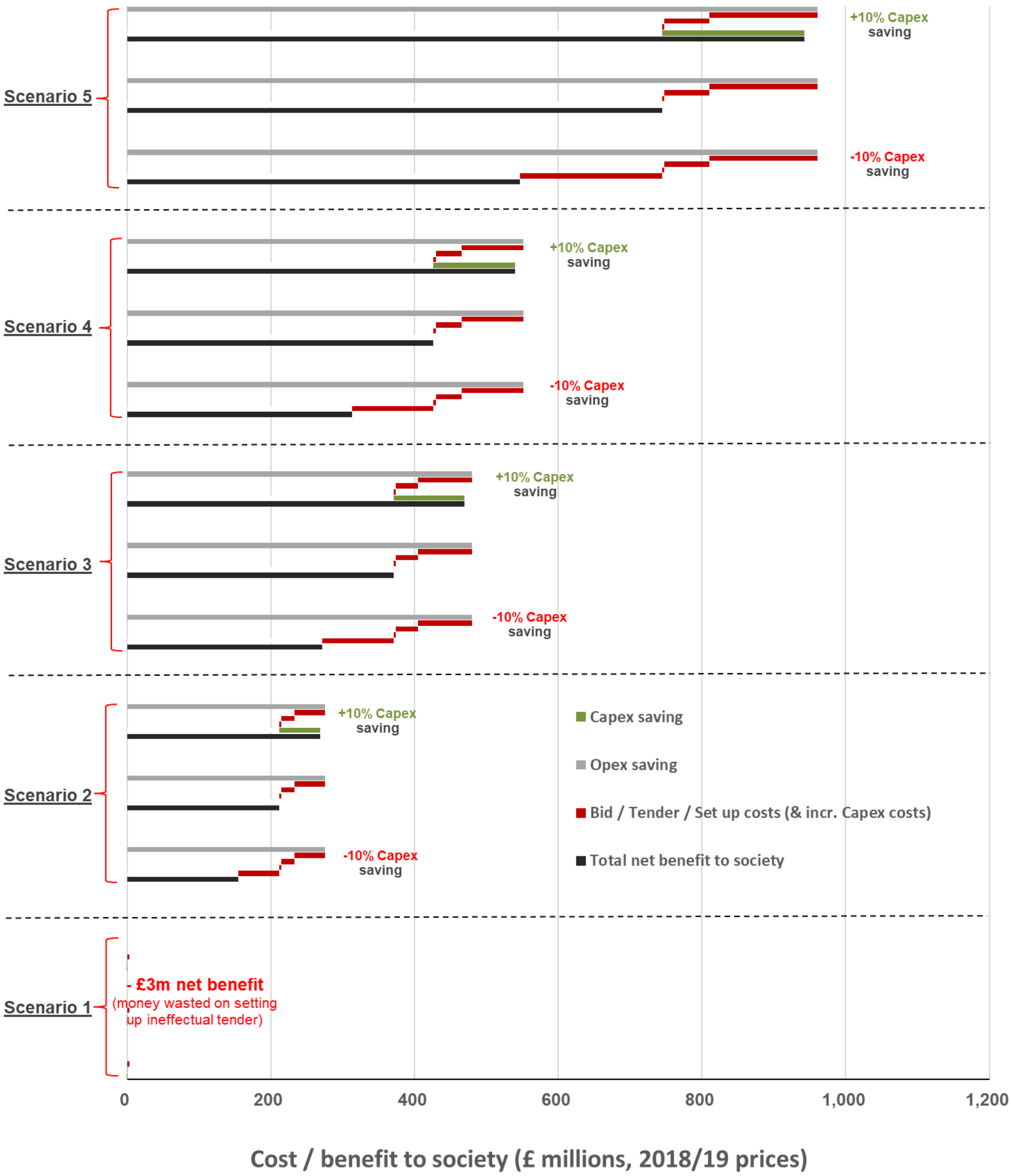
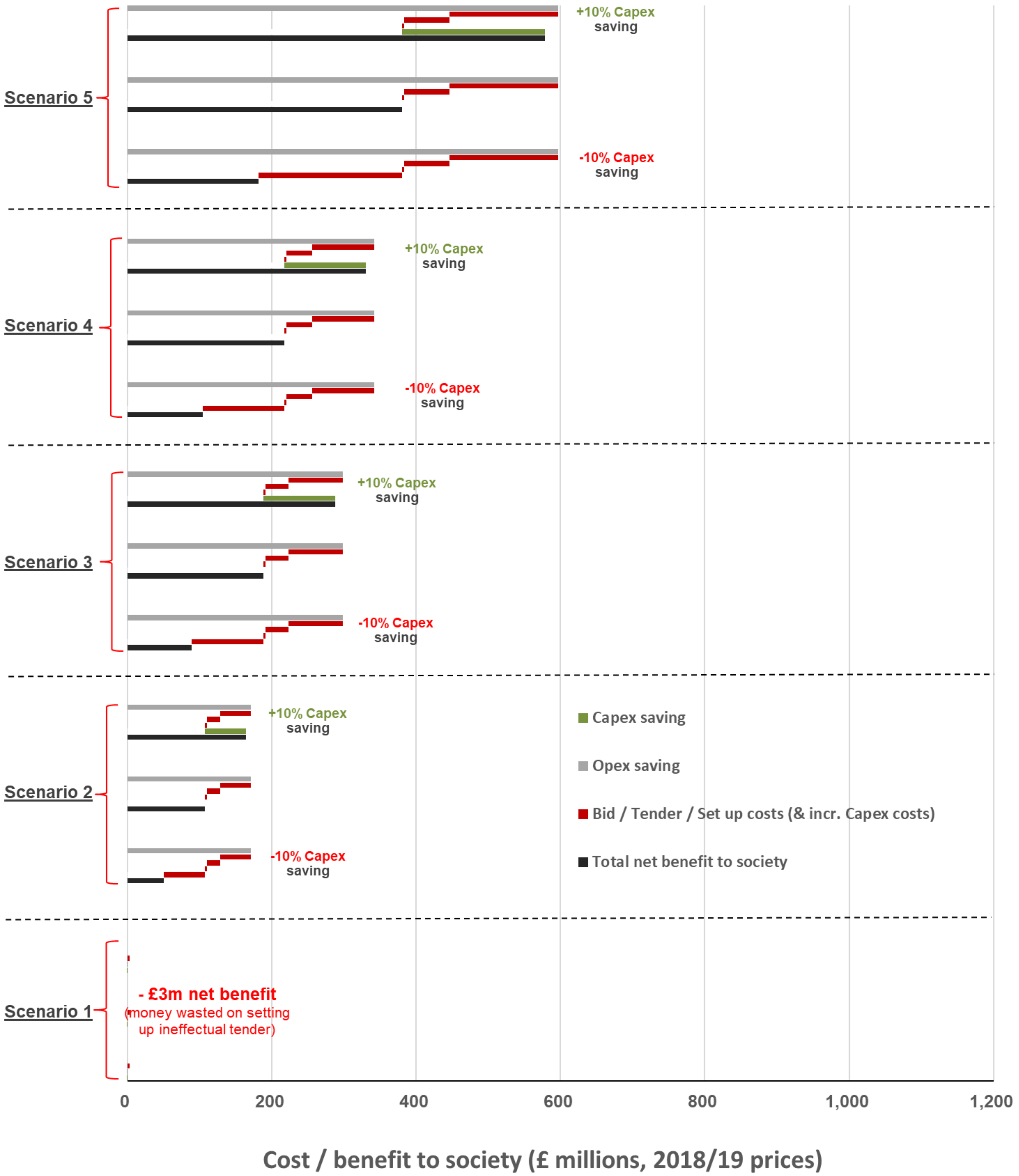


Chart 4. Pipeline scenarios 1-5: Opex PESSIMISTIC (sensitivity)

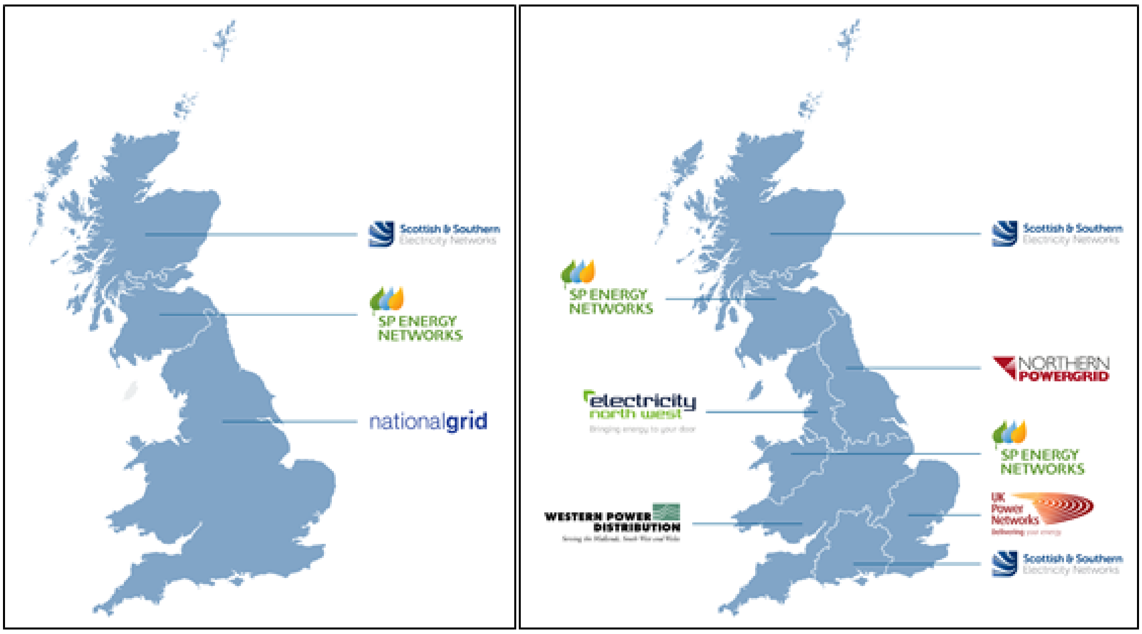
range of estimated benefits (NPV over 32 years)



Background and problem under consideration

30. Great Britain's electricity network is a mixture of high and low voltage infrastructure that conveys electricity through Great Britain, her territorial seas and the wider Renewable Energy Zone. It consists of three integrated transmissions networks (each owned by one of three transmission operators - TOs) and fourteen integrated distribution networks (owned by six distribution operators – DNOs). The TOs and DNOs are responsible for maintaining, reinforcing, and extending their network which is geographically limited in scope (see figure 1). Licences granted to the network operators by Ofgem set out their responsibilities, obligations and, ultimately, their allowed revenues. The System Operator (SO) is responsible for directing and coordinating the flow of electricity across the National Electricity Transmission System (NETS) and works with the three TOs to ensure this happens.

Figure 1: Electricity transmission (left) and distribution (right) network owners in the GB mainland



Onshore electricity transmission and distribution – regional monopoly regime

31. There are nine electricity network operators in mainland GB. At the transmission level: National Grid Electricity Transmission (NGET) in England and Wales, Scottish Power Transmission (SPT) in the south of Scotland, and Scottish Hydro Electric Transmission (SHE-T) in the north of Scotland. At the distribution level: Scottish Hydro Electric in the north of Scotland and the south coast of England, Scottish Power Energy Networks (SPEN) in the south of Scotland, Merseyside and north Wales, Northern Power Grid (NPG) in Northumbria and to Hull, Electricity North West (ENW) for Cumbria, Western Power Distribution (WPD) for the Midlands, South Wales, Devon and Cornwall, and UK Power Networks (UKPN) for the South East, London, Kent and the east Midlands.

32. The Electricity System Operator, a legally separate entity within the National Grid Group, provides the role of SO across the NETS. The network owners operate as monopolies in their geographically-defined network regions. Because they are monopolies, Ofgem[1], as the network regulator, seeks to ensure value for money for consumers through price control regulation, which

[1] https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf

serves to limit the amount of allowed revenue that a network company can take over the length of a price control period. The network companies recover their allowed revenues through charges to generators and suppliers who in turn pass them through to customers. Allowed revenues are set at a level which covers the companies' costs and allows them to earn a reasonable return, subject to them delivering value for consumers, behaving efficiently and achieving their targets.

33. Ofgem agrees the price control for a particular network company by setting a revenue cap for the business, based on the size of its asset base and its projected investment over the period of the price control. The revenue cap will take account of the operating cost of the asset base, depreciation, tax, the development work and investment the company intends to take forward, and the cost of capital of maintaining and developing the network. Once the revenue cap has been set, the network company is responsible for running its business and meeting its licence and statutory obligations (which include maintaining an efficient, coordinated and economic system)[2] within the limits of that cap. They can also benefit (or suffer) from over-performing (or underperforming) against Ofgem's cost estimates.

34. The previous price control for onshore electricity transmission networks, 'RIIO-T1'[3], ran from 2013-2021 and for electricity distribution, 'RIIO-ED1', is currently running for 2015-2023. In some cases, investment in the system need only be taken forward if certain projects are undertaken. Because there was uncertainty when finalising the RIIO-T1 price control regimes about the timing of and need for such projects, network companies were able to bring forward certain high-value[4] projects for regulatory approval through the so-called 'Strategic Wider Works' process. This helps to ensure that transmission assets are in place to connect new, large generation projects (for example), while also ensuring that investments are in the interest of existing and future consumers. Ofgem set out that projects brought forward under the SWW regime could be subject to competition.[5]

35. The SWW regime was a mechanism that allows Transmission Owners (TOs) to bring forward large investment projects that were not part of the RIIO-T1 price control settlement. It has been used by Ofgem to regulate the delivery of several such projects, ensuring that they are implemented efficiently.[6] However, the SWW did not introduce competition to project delivery, as the incumbent TO is expected to deliver the project under the mechanism. For RIIO-T2, SWW has been replaced by Large Onshore Transmission Investments (LOTI), which also does not introduce competition to project delivery.

36. Ofgem started the 'Extending Competition in Transmission' project in 2015 to consider the most appropriate ways to introduce competition into onshore electricity transmission networks. The project initially focussed on the CATO (Competitively Appointed Transmission Owner) model[7], which involves the award of a licence to a party following a competition run by an independent party. The CATO model considered both 'late' (post planning consent) and 'early' (pre planning consent) competitions. Development of the CATO model was paused in 2017 following delays to the introduction of enabling legislation. In mid-2017 Ofgem developed the Special Purpose Vehicle (SPV) model as an alternative mechanism that allows Ofgem to introduce competition to the delivery of large onshore electricity transmission projects. Under the SPV model, the

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[2] Section 9(2) (a) of the Electricity Act 1989 states that transmission licensees have a duty to "develop and maintain an efficient, co-ordinated and economical system of electricity transmission".

[3] The RIIO T1 price control (Revenues = Incentives + Innovation + Outputs) ran from 1 April 2013 to 31 March 2021.

[4] The onshore TOs each have a different threshold value level for Strategic Wider Works: NGET=£500m; SPT=£100m; SHE-T=£50m. See: Ofgem, 'SWW Guidance (Version 2)', published October 2013, https://www.ofgem.gov.uk/publications-and-updates/guidance-strategic-wider-works-arrangements-electricity-transmission-price-control-riio-t1-0, p. 23

[5] See 'Competition Assessment' in Ofgem, 'Strategic Wider Works FAQ', published December 2013, https://www.ofgem.gov.uk/publications-and-updates/strategic-wider-works-faq

[6] Ofgem, 'Strategic Wider Works – Delivery of large onshore electricity transmission projects', https://www.ofgem.gov.uk/electricity/transmission-networks/critical-investments/strategic-wider-works

[7] Ofgem, 'Quick Guide to the CATO Regime', published November 2016, https://www.ofgem.gov.uk/publications-and-updates/quick-guide-cato-regime-november-2016

incumbent TO would run a tender to appoint an SPV to finance and deliver a project on its behalf through a contract in effect for a specified revenue period – usually covering the period of its construction and 25 years of operation.[8]

37. Ofgem have regularly reviewed the arrangements for planning and delivery of onshore electricity transmission networks in GB.[9] In September 2018, Ofgem published an Impact Assessment on applying the SPV model to future new, separable and high value projects, which concluded that the application of the SPV model could lead to potentially significant savings for consumers, although those savings were not likely to be as large as under the proposed CATO model.[10] In mid-2019 Ofgem published its decision to seek to apply competition (whether under the CATO, SPV or Competition Proxy Models) to new, separable and high value electricity transmission projects coming forward under the RIIO2 price control period. In December 2020 Ofgem published its Sector Specific Methodology Decision outlining its decision to use the same criteria to identify projects that may be suitable for late model competition across all sectors, including electricity distribution over the RIIO-ED2 price control period.[11]

Offshore transmission – competitive delivery

38. Offshore transmission concerns the transmission of electricity from an offshore generating station such as a wind farm to the mainland grid[12]. Increasing levels of offshore wind generation in the past decade created a need for a process to identify the party that would be responsible for owning and operating these connections. The Energy Acts of 2004 and 2008 amended the Electricity Act 1989 to enable Ofgem to run a competitive process to identify the party to be awarded a licence for this purpose. Such licensees – offshore transmission owners – are known as 'OFTOs'.

39. The first competitive tender for an offshore connection was launched in July 2009. Interested parties submit bids to purchase, maintain, operate, and receive a regulated return from an offshore transmission asset for 20 to 25 years[13]. To date, the competitive tender regime has granted 21 licences to transmission assets worth approximately £6 billion[14]. A further 25 projects, worth approximately £22 billion, are also in the pipeline[15].

40. In May 2014, an independent report commissioned by Ofgem[16] found that in the first tender round, which consisted of nine projects and £1.1 billion[17] worth of investment, the competitive offshore transmission regime generated savings of £260-£500 million[18] against any other plausible counterfactual regime. In March 2016, a subsequent independent report commissioned

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8 Ofgem, 'Impact Assessment on applying the Special Purpose Vehicle model and Competition Proxy model to future new, separable and high value projects', published September 2018, https://www.ofgem.gov.uk/publications-and-updates/update-extending-competition-transmission-and-impact-assessment, p. 2

9 https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission

10 Ofgem, 'Update on Extending Competition in Transmission and Impact Assessment', published September 2018, https://www.ofgem.gov.uk/publications-and-updates/update-extending-competition-transmission-and-impact-assessment

11 Ofgem, 'RIIO-ED2 Sector Specific Methodology Decision', published December 2020, https://www.ofgem.gov.uk/publications-and-updates/riio-ed2-sector-specific-methodology-decision

12 Note that offshore transmission is distinct from cross-border transmission. The latter relates to the high-voltage lines that link the National Electricity Transmission System (NETS) with transmission systems in other countries.

13 The most recent tender round, TR6, has extended the operational period to 25 years to reflect technological developments in the sector.

14 Unclear price base. Sourced from: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders

15 Unclear price base. Sourced from a combination of Ofgem's OFTO website: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders and NGESO's TEC register: https://data.nationalgrideso.com/connection-registers/transmission-entry-capacity-tec-register

16 CEPA/BDO, 'Evaluation of OFTO Tender Round 1 Benefits', published May 2014, https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf

17 Unclear price base. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', Figure 4.1, published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, p. 12

18 2018/19 prices. Original figures (2014/15 prices) were in the range of £245-470 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', Table C.1, p. 68

by Ofgem[19] found that in the second and third tender rounds, with six projects and around £1.7 billion worth of investment, the generated savings were in the £460-£800 million range[20].

41. The 2016 report considers five counterfactual cases, and identifies, for example, £563 million of NPV savings (excluding tax) against a counterfactual where capital costs were low, and the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime (Counterfactual 3).[21] These savings were split broadly equally between the financing and operation of the assets. The report notes that competitive tendering led to savings through innovation and different contracting approaches. The report concludes that the offshore tendering approach offers lessons for structuring other contestable infrastructure opportunities.

[19] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits'

[20] 2018/19 prices. Original figures (2014/15 prices) were in the range of £425-750 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', tables 6.1 & 6.2, pp. 36-38

[21] 2018/19 prices. Original figure (2014/15 prices) amounted to £526 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', tables 6.1 & 6.2, pp. 36-38

The problem under consideration

42. Government believes that there would be benefit in introducing a competitive process for the allocation of licences and/or contracts for onshore electricity networks. However, because the current legislative framework only allows for the competitive allocation of licences for offshore transmission, primary legislative change is needed.

Rationale for intervention

43. In the coming years, significant investment will be needed in the electricity network to support the increased electricity demand and renewable generation needed to meet our Carbon Budget targets and achieve Net Zero, in a way that is secure, sustainable and affordable and value for money for consumers. Approximately a fifth to a quarter of the typical household electricity bill in 2019 was made up of the cost of transporting electricity from the place that it was generated to the customer[22]. Government is committed to looking for opportunities to bear down on these costs and reduce those being passed through to consumers. The experience of competitive delivery of offshore licences shows that significant savings can be made through a competitive approach to network solution delivery.

44. Competition can drive companies to rationalise costs, increase efficiency and improve productivity. Competition can also encourage access to a wider and more diverse pool of labour across different organisations, as well as promoting innovation. Access to more sources of capital can provide timely investment, and natural competitive drivers can lead to lower pricing for goods and services.

45. Government has sought to promote competition in other parts of the energy market. The outcomes of the third round of the Contracts for Difference auctions, in which renewable energy projects compete for a fixed-term contract to provide electricity, were announced in late 2019, and resulted in a clearing price for Offshore Wind which was almost 70% lower than negotiated contracts from 2013 (a clearing price of around £40/MWh[23] in 2012 prices, which is close to the wholesale price). Further, and as outlined above, competitive tendering for offshore transmission connections has provided savings of £730m-£1,170m across the first fifteen projects[24].

46. Whilst elements of the RIIO framework serve as a proxy for natural competition, such as Ofgem's process of comparing and benchmarking network company costs against each other, a number of market failures persist:

    a. **Market power and barriers to entry**: The incumbent network operators currently have monopoly rights over the planning, construction and operation of all network assets in their respective regions. While network operators already competitively tender certain aspects of their projects, they retain overall control and cost information. This prohibits the ability of other parties to participate fully in the market, regardless of the fact that they may be able to deliver assets more efficiently. Limiting the size of the market also limits innovation, approaches to procurement, price-reflectivity, financing and construction.

    b. **Imperfect information**: Ofgem does not currently have access to the same level of information as the companies it regulates. While incumbent network operators engage with the supply chain by, for example, running tenders for construction of network assets, Ofgem is only presented with a single source of information and no choice over which party owns and operates a particular asset. This information asymmetry reduces the size of the Authority's evidence base and in turn weakens its ability to bear down on costs. Competition can bring increased diversity in the industry, which will increase the sources of information that Ofgem can use to assess cost submissions. This should provide a more effective means of revealing the true costs incurred by network operators and reveal efficient prices more quickly than negotiations and the benchmarking[25] process alone. This will strengthen Ofgem's ability to bear down on costs for those assets that continue to be regulated through the price control process.

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[22] https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill. Estimate based on an average electricity bill for a typical domestic customer of the six large suppliers

[23] https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-3-results

[24] 2018/19 prices. Original figures of £680-1,090m (2014/15 prices) can be found in CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', p.54, published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[25] 'Benchmarking', is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.

c. **Foregone positive externalities**: Restricting competitive tendering to offshore transmission restricts in turn the positive externalities associated with increased competition. This is because increased competition brings long term innovation benefits beyond the reduced costs of those firms that take part in a tender. Firms, in their drive to gain market share, are more likely to draw on innovative technologies and to increase their investment in research and development. This will in turn drive costs down in the long run for the industry overall.

Policy objectives

47. The principal policy objective of this measure is to push the costs of developing and operating certain onshore network solutions to the efficiency frontier by putting in place a legislative framework that is expected to allow a body(ies) appointed by Secretary of State to run competitive processes for identifying the licence or contractholder(s) that can build and operate such solutions. Government recognises that it is unlikely to be cost-effective for Ofgem, business, or the consumer to run a competitive tender for all onshore network assets. The societal costs of running a tender for a small project, for instance, would likely be higher than any savings achieved by running it. As such, only those assets which meet a certain set of technical criteria will be eligible for competitive tender. These criteria may be changed over time to ensure that increasing efficiency and future technological developments can be reflected in the decision as to whether or not to run a tender. Government will ensure sufficient flexibility within the legislation to extend competition to distribution level in the future if this is in the interest of consumers. The impact of doing so would be considered in future impact assessments at the appropriate time.

48. Ofgem and Government are considering the type of network assets suitable for competitive tender, and significant work has already been conducted considering how to define such assets at the transmission level. In January 2018, Ofgem confirmed three criteria for onshore transmission competition, as set out below, remain appropriate[26]:

    a. The asset must be **new**. This is a readily-comprehensible criterion which has the benefit of making it easy for industry to identify which assets may be tendered.

    b. The asset should be '**high value**'. The cost savings from competitive tendering are at least partly proportional to the value of the asset being tendered; the greater the value of the asset, the greater the cost savings. There is a certain level of cost associated with running a tender that cannot be escaped (although may be reduced over time and with process familiarity), and additional costs may be incurred depending on the value and complexity of the asset that is being tendered. In order to realise benefits from competition, the value of the asset needs to be significant enough that the cost savings outweigh the costs.

    c. The asset should be '**separable**' from the rest of the network. This means that projects should be easily identifiable as discrete projects and that ownership and operational boundaries and responsibilities are clear. Separable projects are more easily scoped and defined, giving greater clarity on the opportunity presented by the tender.

49. We expect these to be applicable under the legislative framework for transmission solutions, and are asking whether the high value threshold of £100m remains appropriate in our associated consultation document. **For the purposes of this IA, we will consider all projects are installed at the onshore transmission network level and satisfy the criteria above.**

50. For the purposes of this IA, it has been assumed that incumbent network operators will be able bid for licences or contracts that will enable them to operate onshore network assets.

[26] https://www.ofgem.gov.uk/publications-and-updates/update-competition-onshore-electricity-transmission

Government and Ofgem will undertake further work to understand how best to manage and prevent any conflicts of interest that may arise as a result of the fact that market incumbents necessarily possess more information about the nature of the network in their region than new market entrants.

Policy options considered, including alternatives to regulation

51. Four options have been considered in this IA (two main and two alternative options). While costs and benefits are only expected once secondary legislation has come into force and relevant policies have been implemented, for transparency only the two main options have been appraised qualitatively in detail and, where possible, quantitatively (based on the competitive tendering experience in offshore transmission, and Ofgem's Special purpose Vehicle model). Two alternative options were considered, but have not been appraised quantitatively due to their inherent limitations:

    - **Do Nothing:** The status quo continues. Offshore transmission assets can be competitively tendered, but all onshore network assets continue to be built, owned and operated by the incumbent, monopoly owners of the networks in their respective areas.
    - **Policy Option:** Government will introduce changes to primary legislation that enable a body appointed by the Secretary of State to tender competitively those onshore electricity network solutions where indicative solutions to the constraint at hand meet criteria set by the Secretary of State. The expectation is initially to extend competition to new, high value and separable onshore transmission network assets. The benefits of extending competition to onshore distribution network assets was not quantified at this stage. This is the preferred option.

52. There are two alternative options to legislative change of the kind described here, neither of which Government believes are desirable.

    - **Alternative 'Do Nothing' Option**: Using existing powers, Ofgem could award licences for the construction and operation of onshore network assets without corresponding primary legislation. In order to achieve benefits associated with competition, Ofgem has already considered alternative ways in which it could introduce competition (and/or replicate its effects) under its current powers i.e. the Competition Proxy model (CPM) and Special Purpose Vehicle (SPV) model.[27] In the case of the CPM, it was considered that this would not bring the benefits of true competition, as monopolies remain, and so costs are estimated by benchmarking against other network companies alone. In the case of the SPV model the full benefits of competition are more difficult to achieve due to the need for the monopoly provider to run the competition and contract with the winning bidder. This risks sub-optimal outcomes as a result of inefficient running of the competition and/or allocation of risk. In addition, hurdles remain for third parties entering the market without legislation, so the benefits associated with new markets and businesses developing will not arise and subsequently Industrial Strategy aims are not contributed to by this option. Without a clear legal framework in place, investors may be less willing to come forward, weakening the level of competition and reducing the potential savings for consumers.
    - **Alternative 'Policy Option'**: Government could introduce legislation that enables a body appointed by the Secretary of State to run the tenders to award licences for the construction and operation of certain onshore network licences on a competitive basis, but mandate competition for *all* assets, regardless of size, newness or other criteria.

[27] The CPM & SPV are both 'late competition' models as defined in Ofgem's 'RIIO-2 Sector Methodology' (published December 2018), https://www.ofgem.gov.uk/publications-and-updates/riio-2-sector-specific-methodology-consultation. These differ from 'early competition' models, in that the latter are designed to deliver creative and novel ideas that solve network problems, whereas 'late competitions' are used for the delivery of projects that have already been designed and obtained the necessary consents.

Government expects this would be disproportionate and that, competitive tendering of onshore network assets will only lead to benefits for consumers in certain circumstances.

53. These alternative options will not be considered further in this IA.

Monetised and non-monetised costs and benefits of each option

54. As set out above, costs and benefits are only expected once secondary legislation has been implemented and the two main options have been appraised qualitatively and quantitatively, where possible, for transparency.

1. Do Nothing

55. There is no change to primary or secondary legislation in 'Do Nothing' and, therefore, there is no cost. The sections below set out the costs of the status quo for baseline purposes only to be able to enable a comparison with the costs associated with the 'Policy Option' where the costs are non-zero.

1.1 Cost of network assets assumed eligible

56. In order to estimate the savings under the 'Policy Option' resulting from improved cost discovery and more efficient prices, it is necessary to set out which onshore network assets would be eligible for competition and what their costs are under 'Do Nothing'.

57. There is a high degree of uncertainty around the scale and timing of the pipeline of projects that would be potentially eligible. There is also a high degree of commercial sensitivity around using information from the actual project pipeline. To account for this uncertainty, five stylised pipeline scenarios of investment over the next 10 years that abstract data from specific projects are considered (see Table 4). There is no end date to the proposed Policy Option, so the 10-year cut-off for new assets coming forward has been assumed for the purposes of this IA.

58. These scenarios use historic capital expenditure information over the Transmission Price Control Review 4 (TPCR4) period from 2007/08 to 2012/13 (as estimated by Ofgem) under schemes such as Transmission Investment for Renewable Generation (TIRG)[28] and the Transmission Investment Incentives (TII)[29] framework. These pipeline scenarios also use data from RIIO-T1 (via the Strategic Wider Works (SWW) investment mechanism[30]) and ED1 price control regime.[31]

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[28] www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview
www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-sp-transmission-ltd-and-scottish-hydro-electric-transmission-ltd

[29] Ibid.

[30] www.ofgem.gov.uk/ofgem-publications/52669/jul12whvdcdecisionfinal.pdf; www.ofgem.gov.uk/ofgem-publications/84439/finaldecisionletter-kintyrehunterston.pdf; www.ofgem.gov.uk/ofgem-publications/87262/decisionontheproposedbeaulymossfordreinforcementunderriio-t1strategicwiderworksarrangements.pdf; www.ofgem.gov.uk/ofgem-publications/91977/decisiononourassessmentofthecaithnessmoraytransmissionproject.pdf

[31] See Ofgem, 'ET1 PCFM November 2018', published November 2018, in 'RIIO-ET1 Financial Model following the Annual Iteration Process 2018', https://www.ofgem.gov.uk/publications-and-updates/riio-et1-financial-model-following-annual-iteration-process-2018

Table 4: 'Do Nothing' Assumed Asset Costs across Pipeline Scenarios (2018/19 prices)

	Annual	Total investment over next 10 years (undiscounted)
Scenario 1	£0 per year	£0
Scenario 2	£550m every other year	£2.2bn
Scenario 3	£550m per year	£3.9bn
Scenario 4	£1.1bn every other year	£4.4bn
Scenario 5	£1.1bn per year	£7.7bn

59. Scenario 1 represents an extreme lower bound where no project is deemed eligible under the chosen criteria over the next 10 years, hence there being no investment. Scenario 5 represents an extreme upper bound with £1.1bn worth of assets per year being deemed eligible and therefore £1.1bn per year of investment (an undiscounted total of £7.7bn investment over the next 10 years given that the first three years are used for a competition set up and the first tender round). These extremes are based on high value transmission assets being brought forward in particular years over the TPCR4 period but are unlikely to be a permanent phenomenon. Scenario 3 represents the central case as it is roughly equivalent to investments made on new assets over the course of the TPCR4 by TOs – approximately £4.3bn worth of capital investment was spent on new assets to connect new electricity generation capacity to the network between 2007 and 2014.[32] Though it is worth noting that even this scenario is quite conservative – in reality, TOs are expected to substantially increase their investments going forward due to increased demand from the electrification of heat and transport – so using past investment trends is likely to underestimate the benefits of this intervention. However, this IA has opted to use more conservative estimates due to uncertainty around how many of these future assets would meet the eligibility criteria for competition.

60. Overall, the pipeline scenarios encompass the levels of investment that has occurred over the RIIO-T1 and ED1 price control regimes.[33] Discussions with Ofgem have confirmed that the above set of pipeline scenarios are also broadly in line with the potential pipeline of projects under RIIO-T2 that might meet the criteria for competition (based on current draft RIIO-T2 business plans).

61. Scenario 3 includes an annual investment of £550m (an undiscounted total of £3.9bn investment over the next 10 years) roughly represents the average annual investment over TPCR4. It is possible that projects eligible for competition are brought forward on a less frequent basis, rather than, for instance, every year. To account for this intermittency, Government has included two further scenarios, i.e. £550m every other year (Scenario 2) (an undiscounted total of £2.2bn investment over the next 10 years) and £1.1bn (Scenario 4) every other year (an undiscounted total of £4.4bn investment over the next 10 years). Scenario 5 represents an extreme upper bound, with an annual investment profile of £1.1bn per year (an undiscounted total of £7.7bn

[32] 2018/19 prices. Original figure of £3.9bn (2012/13 prices) can be found here: Ofgem, 'Transmission networks: Report on the performance of Transmission Owners during the regulatory periods TPCR4 and TPCR4RO 2007-08 to 2012-13', published March 2014, https://www.ofgem.gov.uk/publications-and-updates/transmission-networks-report-performance-transmission-owners-during-regulatory-periods-tpcr4-and-tpcr4ro-2007-08-2012-13, p. 7.
This figure is calculated by taking the difference in opening and closing Regulatory Asset Value (RAV) of electricity TOs (plus some additions to account for 'shadow RAV') under the period covered by TCPR4.

[33] See Ofgem, 'ET1 PCFM November 2018', published November 2018, in 'RIIO-ET1 Financial Model following the Annual Iteration Process 2018', https://www.ofgem.gov.uk/publications-and-updates/riio-et1-financial-model-following-annual-iteration-process-2018

investment over the next 10 years). Annex A summarises the investment and operation assumptions.

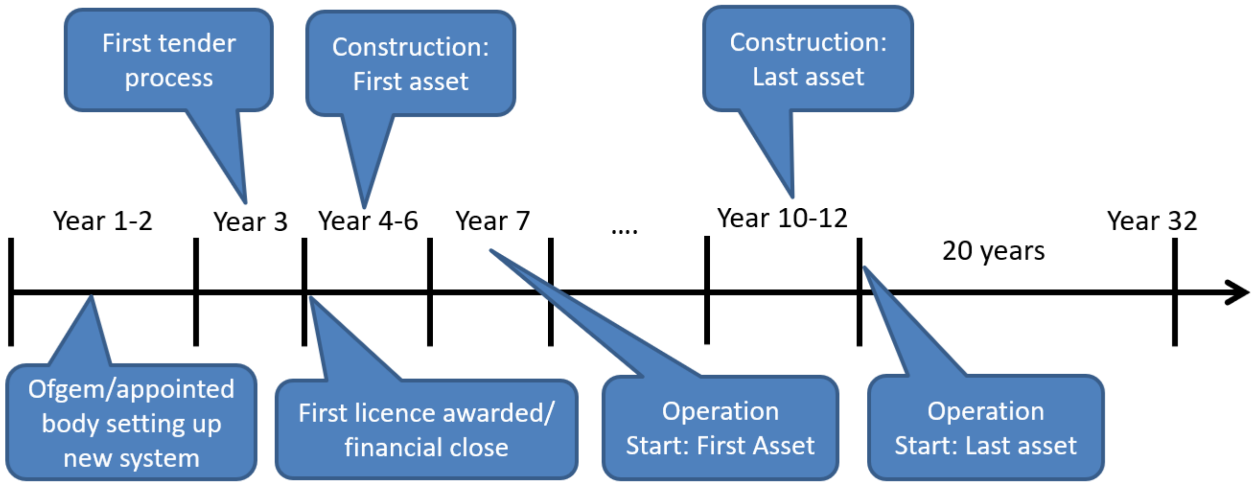
62. Discussions with Ofgem suggest that Scenario 5 is closer to what the TOs are expecting to take forward under the RIIO-ET2 price control period in terms of network investment – up to £1.1bn of investment per year that might meet the criteria for competition.[34] However, there is a risk that this pipeline of planned investment could suffer from delays and attrition, and it is unknown how many of these assets will fully satisfy the criteria for competition. Therefore, this IA purposefully uses a more conservative investment pipeline (Scenario 3) as its central case assumption. Scenario 3 represents a conservative estimate based on the investment profile observed over the last few years – and using it will result in a net benefit to society that is more on the conservative side. However, it is worth noting that the benefits from increased competition could be substantially higher than that suggested by this conservative central scenario.

63. These investment averages can cover one or several projects. Cost implications related to the number of projects are set out under the costs and benefits of the 'Policy Option'.

64. This IA considers the impact of the measure under the 'Do Nothing' and 'Policy Option' scenarios over the same timescale. Ofgem, and therefore this IA, assumes a two-year period to set up the scheme and, for the purpose of this IA, each tender process is assumed to take one year. Most OFTO tenders so far have taken ~18 months,[35] but we have assumed a tender length of 12 months in this IA for the sake of simplicity (the additional 6-month delay implied by an 18-month tender would have a negligible impact on results). The proposed policy does not have an end date. Therefore, this IA assumes assets being built over the next 12 years – i.e. from Year 4 up to Year 12 with 3 years of construction per asset – with savings occurring over a 20-year time period for each of these assets (based on the offshore experience). This is set out in further detail in Annex A. Furthermore, it is assumed that construction costs are incurred in the year following the tender, with construction taking three years per asset. Therefore, this IA assumes that asset operation will start three years following the tender. It is assumed that under 'Do Nothing', the timing of the financial close of assets is the same as under the 'Policy Option'. Figure 2 sets out the assumed timings.

65. This IA assumes 2023 as a start year for scheme set-up (Year 1), with the first potential financial close in 2026. Note that a later start date for the stylised scenario analysis in this IA would only alter the degree of discounting assumed in the NPV of the proposed 'Policy Option'. Undiscounted costs and benefits would remain unchanged.

Figure 2: Assumed Timings in this IA



1.2 Cost of regulation for transmission assets assumed eligible

66. Under the 'Do nothing' option there are costs associated with regulating large transmission such as those falling under TIRG, TII or SWW. These include costs associated with eligibility, needs case and project assessment stages, as well as a consultation phase. Costs are incurred by both Ofgem and the TOs. Ofgem estimates that this process takes approximately 12-15 months from the start of the assessment process to a funding decision for well-evidenced proposals[36] (but it can take upwards of 2 years for many projects) but is unable to provide an estimate for these costs in isolation. The costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial. Increased competition is likely to reduce overall regulatory costs for Ofgem – these counterfactual costs and potential regulatory savings (in excess of scheme management and set-up costs) are not quantified however, as Ofgem does not have a separate estimate for these costs.

67. Costs of regulation faced by Ofgem are passed on to the network businesses that hold licences for gas transportation, electricity transmission with system operator conditions (National Grid Electricity System Operator), and electricity distribution. Costs are currently passed through to licensees proportionate to the number of customers they serve. These costs are treated as 'pass-through costs', which means that licence holders, in turn, recover the costs from generators and suppliers, which ultimately pass costs onto consumers. In addition, licensees also face costs of regulation. Costs of regulation faced by licensees directly, in addition to those passed through to them by Ofgem, are also assumed to be ultimately passed through to consumers in this IA. This principle is integral for assessment of these costs (and their reduction) in the IA, which shall be demonstrated through the costs and benefits under the 'Policy Option' below.

1.3 Interface costs of the System Operator (SO)

68. Currently, the System Operator (National Grid Electricity System Operator) already interacts with a range of industry actors, including three onshore TOs, a number of OFTOs, 14 different DNO regions and interconnector operators. For the purposes of this IA, these interface costs have not been quantified for use as a counterfactual under 'Do Nothing', because additional new entrants under the 'Policy Option' are expected to cause only marginal changes for the SO (costs are assumed to be zero). Therefore, there is no change in costs between 'Do Nothing' and the 'Policy Option'.

[36] https://www.ofgem.gov.uk/sites/default/files/docs/strategic_wider_works_factsheet_0.pdf

2. Policy Option (compared to 'Do Nothing')

69. This section provides a qualitative and, where possible, quantitative assessment of these costs and benefits of the Policy Option. These costs and benefits are classified as direct impacts from the time that secondary legislation is implemented as they are expected to result directly from the implementation of secondary legislation.

70. The quantifications represent approximations and ranges of potential costs and benefits. They are intended to provide a sense of scale rather than precise costs and benefits which Government expects from competition. It is inherently difficult to predict with any accuracy the potential efficiency benefits that introducing a competitive process might bring, given the many uncertainties around the project pipeline, and the fact that examples of the use of competition in transmission delivery are context specific. It is also difficult to quantify meaningfully the dynamic benefits of competition, such as the scope for increased innovation and the introduction of new products, services and technologies.

2.1 Additional costs (monetised / non-monetised) as compared to 'Do Nothing'

71. Table 5 below sets out the additional categories of costs and benefits identified with regards to the 'Policy Option' as compared to 'Do Nothing'.

Table 5: Costs and Benefits

	Costs	Benefits

Generators/ Suppliers and ultimately end-consumers ("Consumers")	• Set-up/Tender/Bid costs (of successful bidders) (TO pass through) [3] – *monetised*
	• Costs due to delay risk – *not monetised*
	• Costs due to delay risk (TO pass through) – *not monetised*
		• Cost savings through more competition
		  ○ Better information for Ofgem benchmarking – *not monetised*
		  ○ Innovation (technical, commercial, financial) – *not monetised*
		  ○ More efficient and innovative procurement practices – *not monetised*
		  ○ New sources of labour and capital – *not monetised*
		  ○ Increased diversity in the industry – *not monetised*
		  ○ Improved timescales – *not monetised*
		  ○ Widening of expertise in different areas of the network and potential widening of investment activity in other areas of the industry – *not monetised*
		• Lower cost of regulation under the price control (TO pass-through) [3] – *not monetised*

Incumbent Transmission Operators ("Producers")	• Bid costs – *monetised* • Potentially foregone returns on assets (transfer within the producer group) – *not monetised* • Costs due to delay risk – *not monetised* • Tender costs (Ofgem/appointed body pass through) – *monetised*	• Lower cost of regulation under the price control – *not monetised* • Lower cost of regulation under the price control (Ofgem/appointed body pass-through) – *not monetised* • Reduced expenditure on transmission assets due to not being appointed successful bidder (transfer within the producer group) or due to revealing a more efficient cost – *not monetised*
ESO	• Set up costs (Ofgem/appointed body pass through) – *monetised* • Additional interface costs – *not monetised*	
New entrants ("Producers")	• Bid costs – *monetised* • Potentially higher expenditure on transmission assets (transfer within the producer group) – *not monetised* • Costs due to delay risk – *not monetised* • Tender costs (Ofgem/appointed body pass through) – *monetised*	• Potential for market entry – *not monetised* • Potential gain of returns on assets (transfer within the producer group) – *not monetised*
Ofgem (or body appointed by the Secretary of State to run the tenders)	• Tender costs (directly passed through) [1] – *monetised* • Set-up costs (directly passed through) [1] – *monetised*	• Lower cost of regulation under the price control (directly passed through) [2] – *not monetised* • Reputation and confidence – *not monetised*

Note:
1 The set-up costs that Ofgem or the appointed body incurs are directly passed through to the ESO and Ofgem's or the appointed body's tender costs are directly passed through to incumbent TOs or new entrants. These are considered to be direct costs to the ESO, incumbent TOs and new entrants. Note that in future some set-up costs may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender rather than from the ESO (this would also be a direct cost to business).
2 The lower cost of regulation under the price control for Ofgem is directly passed on to incumbent TOs. This is considered to be a direct benefit to incumbent TOs.
3 Based on the offshore experience, set-up, tender and bid costs (of successful bidders) passed through to generators/suppliers and ultimately end-consumers. The same holds for lower cost of regulation under the price control (benefit). These costs/benefits are considered indirect impacts of the 'Policy Option' through incumbent TO or new entrant recovery/pass through.

72. For the purposes of this IA:
    a) 'Set-up costs' are the one-off costs associated with creating the competitive regime;
    b) 'Tender costs' are the costs associated with running a particular competitive tender; and
    c) 'Bid costs' are the costs of bidding into a particular competitive tender.
73. In order to estimate the additional costs associated with extending competitive tendering to some transmission assets, this IA relies on the findings from the offshore transmission asset experience, assessed in the CEPA report on OFTO Tender Rounds 2 and 3[37]. For the purposes of the quantifications in this IA, cost savings are estimated against a price control counterfactual from the CEPA report where the transmission asset was constructed, owned and operated by a transmission operator and regulated through the RIIO price control regime. In the CEPA report, this is outlined as "Counterfactual 3", and is the most comparable counterfactual to the 'Do Nothing' option, as well as being the conservative counterfactual.
74. The CEPA report sets out that, against the price control counterfactual (Counterfactual 3) as set out above, the cost to society of the first three OFTO tender rounds of bid costs were between £7m and £45m in each round, for a grand total of £70m across all three tender rounds (NPV).[38] Expressed as a percentage of the total Final Transfer Value (FTV) of OFTOs in those rounds (£2.9bn), bid costs total approximately 2.4% of the asset value on average.
75. Costs incurred by a body appointed by Secretary of State from running the tender process are assumed to be 1% of the asset value. In reality this will vary by project and tender round. For example, in place of one large project, several smaller projects could be tendered in a given year, which may either increase the Secretary of State-appointed body's administration costs (because they are running several projects) or decrease them (because they are running several projects at once). Consequently, 1% represents an appropriate long-run average and is based on Ofgem's, as the body which runs OFTO tenders, experience to date.
76. The 'Assumptions and Risks' section gives the full list of appropriate caveats associated with using the CEPA report for this IA. The list below, however, summarises the key points:
    a) While new entrants are likely to incur a lower capital expenditure than incumbent TOs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. However, as is the case with large investments in other sectors, refinancing is likely to take place post-construction which would almost certainly lower the cost of capital substantially (from its pre-construction level).
    b) Savings in the offshore regime, in particular for TR1, were at least in part realised by offshore generators quoting very low prices for maintenance costs in an attempt to maintain control over their own assets (appointed OFTOs can subcontract operational and maintenance work)[39]. It is arguable that because there is less likely to be a

[37] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits
[38] 2018/19 prices. Original figure of £7m - £42m (2014/15 prices) can be found here: CEPA, 'Evaluation of OFTO Tender Round 2 & 3 Benefits", published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, pp. 36, 38 & 68
[39] https://www.ofgem.gov.uk/publications-and-updates/consultation-cepabdo-evaluation-offshore-transmission-tender-round-1-benefits, p52

corresponding generation asset to attempt to control in an onshore competition, onshore bidders will not be incentivised to bid in this way, and that overall savings may be lower. However, savings could be seen in construction delivery, and there have been genuinely innovative approaches to asset maintenance in the offshore regime by OFTOs which have not subcontracted maintenance to offshore generators, which have brought about savings.

c) Government recognises, as indicated in the CEPA report, that there are limits to the extent to which lessons can be drawn from the CEPA report conclusions for the onshore electricity transmission network, given that the outcomes demonstrated in the report are context - and time - specific. However, Government believes that the onshore projects expected to be captured by competitive tendering share similarities with offshore projects – being new, high-value, and separable – and, therefore, comparisons are reasonable. It is also the case that this report, which estimates the savings realised by introducing competition into the offshore electricity transmission network, is the best indication of the operating savings likely to be realised by introducing competition into the onshore electricity transmission network.

2.1.1 Additional costs to generators, suppliers and ultimately end-consumers under the Policy Option

77. **Set-up/Tender/Bid costs (of successful bidders) (TO pass through):** In the offshore competitive regime:

a) Set-up costs are incurred by the body appointed by the Secretary of State to run the tenders. They are directly passed onto the ESO as part of the ESO's licence condition (direct cost for the ESO, see 'the ESO' section below). The terms of this licence also allow the ESO to consider this cost a 'pass-through' cost for the purposes of the price control: in other words, the costs are recovered from generators and suppliers, who in turn are assumed to pass these costs on to end-consumers.

b) Tender costs are incurred by the body appointed by the Secretary of State to run the tenders. These costs are directly passed onto the successful bidder in a tender round (direct cost for successful bidder). Bidders will build that cost into their proposed revenue stream, which means that the tender costs are ultimately passed on to generators, suppliers, and ultimately end-consumers.

c) Bid costs are in the first instance incurred by incumbent TOs and new entrants (direct cost) (see relevant sections below). If a bidder is successful, this cost will be passed through to generators, suppliers and ultimately end-consumers through the revenue stream. If the bidder is unsuccessful, the costs will formally remain with them, though some informal pass-through to end-consumers may occur if the bidder is already operational in the transmission market.

For this IA Government has assumed that the same will hold for onshore assets. The bid costs of unsuccessful bidders will remain with the bidder. Generators recoup the passed-through set-up, tender and bid costs from end-consumers in the form of higher wholesale prices (if price setting plants are affected) and through higher clearing prices in the Capacity Market (a cost to consumers). In the case of some low carbon plant, costs are passed through in the form of higher clearing prices in Contract for Difference allocation rounds therefore leading to potentially less low-carbon generation uptake within the Control for Low Carbon Levies, which would lead to higher emissions (a cost to society). Suppliers pass the set-up, tender and bid costs to end-consumers through higher network charges on customer bills. Therefore, end-consumers ultimately bear these costs. This IA assumes that all set-up, tender and bid costs are fully passed through to consumers, either informally or formally through the licence. This is based on the offshore experience.

78. In order to estimate the likely scale of the set-up, tender and bid costs borne by end-consumers, this IA applies cost assumptions as supplied by Ofgem and experienced in the offshore competitive tendering process. The set-up cost is assumed to be £3m. The costs for the body appointed by the Secretary of State of running the tender process are assumed to be 1% of the asset value, while bid costs for incumbent TOs and new entrants are assumed to be 2.4% of the asset value. These assumptions, combined with the pipeline scenarios, results in set-up, tender and bid costs of £3m-£216m across scenarios as set out in Table 6 below.

Table 6: Estimated Set-up/Tender/Bid Costs (2018/19 prices)

	Annual*	32 Year Period (PV)
Scenario 1	£0m per year	£3m**
Scenario 2	£19m every other year	£64m
Scenario 3	£19m per year	£110m
Scenario 4	£37m every other year	£125m
Scenario 5	£37m per year	£216m

* The annual figures exclude the appointed body's set-up costs of £3m as these are transitional, one-off costs.
** In Scenario 1, the appointed body's set-up costs are fully recovered through the licence fee (paid by the ESO, direct cost). The ESO passes these costs through to generators/suppliers, which ultimately pass them through to end-consumers. In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost), who will also pass these costs on to generators/ suppliers and ultimately to end-consumers.
Note: All estimates are rounded.

79. **Costs due to delay risk**: There is a risk that generation new build could be delayed due to the time taken to run a tender. It is worth noting that under the 'do nothing' option, the incumbent is still required to tender for much of the delivery for certain appointed projects, so the risk of delay here represents the risk of a longer tender process than under the counterfactual. Added delay in network asset delivery implies direct costs for developers of new generation assets (if they depend on the tendered network asset) as it implies a delay to their timetables. Generators are assumed to pass these costs on to end-consumers. As explained in the paragraph below, the quantifications in this IA assume that the appointed body's framework will prevent any delays from occurring. However, if the generation new build is for wider system purposes – the such as a reinforcement of an existing part of the network – then the cost of delay will be in the form of additional constraint costs paid by consumers.

80. **Costs due to delay risk (TO pass through):** In addition to the direct cost on generation new build, a delay also implies a direct cost to incumbent TOs and new entrants (set out in the relevant sections below). Incumbent TOs and new entrants are assumed to pass on their higher costs to generators and suppliers, in the form of higher charges, which will ultimately be borne by end-consumers. To address the delay risk, Ofgem is expected to develop a tender process that fits with project timings and does not cause additional delays for projects where some early development work has already been completed. Ofgem's general framework is likely to include incentives on the competitively appointed party to encourage timely delivery. Additionally, the robustness of the bidders' delivery plans is likely to be a key aspect of the appointed body's tender evaluation process. These measures are likely to help ensure competitively tendered projects are delivered within the appropriate time frame. The quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

2.1.2 Additional costs to incumbent TOs under the Policy Option

81. **Bid costs**: If incumbent TOs bid in the tender process they incur costs in preparing bids for evaluation, reaching the licence grant and acquiring the asset. Based on the offshore experience, bid costs of successful bidders are estimated to be 2.4% of the asset value. It is not possible to isolate the bid costs falling onto incumbent TOs, should they decide to bid, as it is dependent on the TO success rate in the tender process. For illustration, as an extreme upper bound, it can be assumed that incumbent TOs are the successful bidder in all tenders and therefore face the 2.4% bid costs on all tenders (see Table 7). As set out in the 'Set-up/Tender/Bid costs (of successful bidder) (TO pass through)' section above, this IA assumes that all set-up, tender and bid costs are fully passed through to consumers.

82. The bid costs of unsuccessful bidders are not taken into account due to lack of evidence and commercial sensitivity of this information. They do however present a cost to society. There is no formal mechanism under Ofgem's OFTO regime or price control regime (RIIO) for unsuccessful bidders to recover their bid costs directly from consumers. We assume that the bid costs of unsuccessful bidders remains with them. It is important to note that bid costs for incumbent TOs are partially offset by cost savings under the price control process. Ofgem does not have a separate estimate of these cost savings and they are, therefore, not quantified in this IA.

83. In theory it is possible to roughly proxy total bid costs of all parties – both of successful and of unsuccessful bidders – using anecdotal evidence from TR1, TR2 and TR3. Based on internal discussions with Ofgem, unsuccessful bidders faced costs in the range of 0.1-0.5% of the total capital value of a project being competed, per bidder, over the course of all three tender rounds, with an average of 2-3 unsuccessful bidders per project.[40] As an extreme upper bound, it can be assumed that each project has 3 unsuccessful bidders that all face the same bid cost of 0.5% on the total value of capital investment, and that all these unsuccessful bidders are able to recover these costs from consumers – e.g. in the unlikely scenario that they are all active in the GB electricity market. This approach significantly impacts total bid cost estimates, which can amount to over **£245m** (PV, over a 32-year period) with the inclusion of losing bidder costs, **almost double** the maximum of £150m under pipeline Scenario 5. However, given the uncertainties involved in this extreme assumption, this IA does not include this proxy of total bid costs in the final assessment. Due to the commercial sensitivity of this information, there is little indication as to what proportion unsuccessful bidders are overseas companies with little involvement in the GB electricity market. Companies that fall into the latter category would not be able to pass on the cost of their unsuccessful bids to GB consumers, thus removing it as a 'cost to society.'

Table 7: Estimated Bid Costs (2018/19 prices)

	Annual	32 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£13m every other year	£43m
Scenario 3	£13m per year	£75m
Scenario 4	£26m every other year	£86m
Scenario 5	£26m per year	£150m

Note: All estimates are rounded and these costs and those in Table 9 are mutually exclusive.

[40] Based on internal discussions with Ofgem (September 2019).

84. **Tender costs (Secretary of State's appointed body pass through)**: Under the 'Policy Option', the proposed cost recovery mechanism, would allow the body appointed by the Secretary of State to recover the costs of any tender it conducts (also captured under the 'Ofgem/appointed body' section below). This is a direct cost to the successful bidder. Ofgem estimates that its tender costs are 1% of the asset value. In reality this will vary by project and tender round, but 1% represents an appropriate long run average and is based on Ofgem's experience to date. It is not possible to indicate what proportion of tender costs the body appointed by the Secretary of State will recover from incumbent TOs, as it is dependent on the TO submitting a bid and, if they bid, their success rate in the tender process (the successful bidder of any given tender bears those costs alone). For illustration, as an extreme upper bound, it can be assumed that incumbent TOs are successful bidders in all tender rounds and therefore the appointed body's 1% tender cost is fully passed on to incumbent TOs (Table 8). Incumbent TOs then recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above. If they are not the successful bidder in any tenders, the appointed body would not recover any costs from them and they would only face their own bid costs, which have not been quantified due to lack of evidence.

Table 8: Estimated Tender Costs (Ofgem/appointed body recovery) (2018/19 prices)

	Annual	32 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£6m every other year	£18m
Scenario 3	£6m per year	£31m
Scenario 4	£11m every other year	£36m
Scenario 5	£11m per year	£63m

Note: All estimates are rounded and these costs and those in Table 10 are mutually exclusive.

85. **Potentially foregone return on assets (transfer)**: In the scenario that an incumbent TO does not bid or fails to be appointed as successful bidder for a specific project that previously would have fallen under their regional monopoly, they will lose the right to deliver and operate a project which they otherwise would have retained. The incumbent TO would forego the revenue stream for the investment, but would also not incur the asset costs (set out in the benefits section below). The unsuccessful incumbent TO therefore foregoes the return on the investment.

86. The potential reduction in return for incumbent TOs represents a **transfer within the 'producer' group** (incumbent TOs and new entrants) as a new entrant would instead earn the return (given they would receive the revenue stream and incur the asset cost). For simplicity, for the purpose of this IA it has been assumed that the gain in return for new entrants offsets the loss in return for incumbent TOs. Therefore, the return to the 'producer' group is assumed to be unchanged. While new entrants incur a lower capital expenditure than incumbent TOs, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption on returns being unchanged is a fair one.

87. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how exactly revenue streams will be set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able

to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

88. There might also be transfers *amongst* incumbent TOs, where a TO is the successful bidder for an asset in another incumbent TO's previous regional monopoly area. This IA does not estimate impacts for each individual incumbent TO. Both these types of transfers have not been quantified as they depend on the incumbent TOs (or an individual incumbent TO) submitting a bid and, if they bid, their success rate in the tender process.

89. In addition, incumbent TOs may lose economies of scale, which could push up overall costs in other areas of non-competed business. However, given the size of the incumbent TOs current transmission portfolios and the relative scale of the assets likely to be selected for tendering, this is highly unlikely. Further, by applying suitable criteria in regulation as discussed above, Government will work to ensure that competitive tendering of select projects provides additional cost efficiencies and wider benefits. This IA does not quantify the value of the potential loss of assets or return on these investments as this depends on the incumbent TOs submitting a bid and, if they bid, their success rates.

90. **Costs due to delay risk**: There is a risk that projects could be delayed due to the time taken to run a tender. This would have implications for asset costs. As set out in the 'generators/suppliers and ultimately end-consumers' section above, the quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

2.1.3 Additional costs to the ESO under the Policy Option

91. **Set-up costs (Body appointed by Secretary of State pass through):** The body appointed by Secretary of State incurs set-up costs in creating the competitive regime. In general, Ofgem costs are funded by payments made to the Authority by parties who are licenced by it. With regards the creation of a competitive regime for electricity transmission assets, set-up costs will be recovered from the Electricity System Operator (ESO). These costs therefore constitute a direct cost to business. In future, some costs associated with the setting up of the scheme may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender. This has not been separately quantified as it depends on who would be successful during a competitive tender.

92. **Interface costs**: Under the Policy Option, the ESO could bear an additional administrative burden arising from the requirement to interact with a broader group of industry parties. However, these costs are likely to be negligible (and have here been assumed to be zero) as, under 'Do Nothing', the ESO is already interacting with three onshore TOs and a number of OFTOs, DNOs and interconnector operators. This means that the addition of new parties to the market would have only a marginal effect. The incremental interface cost associated with adding new parties to the network cannot be determined.

93. The 'Assumptions and Risks' section discusses the treatment of preliminary works in the analysis.

2.1.4 Additional costs to new entrants under the Policy Option

94. **Bid costs:** New parties, as bidders in the tender process, incur costs in preparing bids for evaluation. Based on the offshore experience, the bid costs of successful bidders are estimated to be 2.4% of the asset value. It is not possible to isolate the bid costs falling onto new parties as it is dependent on the new entrants' success rate in the tender process. For illustration, as an extreme upper bound, it can be assumed that new parties are the successful bidder in all tenders and therefore face the 2.4% bid costs on all tenders (see Table 9). As set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above, this IA assumes that all tender and

bid costs are fully passed through to consumers, either informally or formally through the licence. This is based on the offshore experience.

95. Note that bid costs of unsuccessful bidders are not taken into account due to lack of evidence and commercial sensitivity of this information. They do however present a cost to society. Usually, the bid costs of unsuccessful bidders remain with them and cannot be passed on directly to consumers. However, unsuccessful bidders that are not regulated and are already active in the energy market can, in theory, pass on the costs of unsuccessful bids to their customers. All bidders can also pass on the costs of unsuccessful bids indirectly, via things like decreased dividends for investors, being forced to find savings in other parts of the business etc. This will represent a cost to society – though quantifying this cost is difficult due to a lack of sufficient evidence. Unlike for incumbent TOs, bid costs relating to preparing the bid are not partially offset by cost savings under the price control process.

96. In theory it is possible to roughly proxy total bid costs of all parties – both of successful and of unsuccessful bidders – using anecdotal evidence and data from TR1, TR2 and TR3. Data from comparable projects suggests that unsuccessful bidders can face costs in the range of 0.1-0.5% of the total capital value of a project being competed, per bidder, with an average of 2-3 unsuccessful bidders per project.[41] As an extreme upper bound, it can be assumed that each project has 3 unsuccessful bidders that all face the same bid cost of 0.5% on the total value of capital investment, and that all these unsuccessful bidders are able to recover these costs from consumers – e.g. in the unlikely scenario that they are all active in the GB electricity market. This approach significantly impacts total bid cost estimates, which can amount to over **£245m** (PV, over a 32-year period) with the inclusion of losing bidder costs, **almost double** the maximum of £150m under pipeline Scenario 5. However, given the uncertainties involved in this extreme assumption, this IA does not include this proxy of total bid costs in the final assessment. Due to the commercial sensitivity of this information, there is little indication as to what proportion unsuccessful bidders are overseas companies with little involvement in the GB electricity market. Companies that fall into the latter category would not be able to pass on the cost of their unsuccessful bids to GB consumers, thus removing it as a 'cost to society.'

Table 9: Estimated Bid Costs (2018/19 prices)

	Annual	32 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£13m every other year	£43m
Scenario 3	£13m per year	£75m
Scenario 4	£26m every other year	£86m
Scenario 5	£26m per year	£150m

Note: All estimates are rounded and these costs and those in Table 7 are mutually exclusive.

97. **Tender costs (Secretary of State-appointed body pass through)**: The intention is that Ofgem will recover the costs to it of conducting a tender (also captured under the 'Ofgem/appointed body' section). This is a direct cost to the successful bidder. Ofgem, as the body which deals with OFTO tenders, estimates that their tender costs are 1% of the asset value. It is not possible to indicate how much of their tender costs the body appointed by the Secretary of State will recover from new parties as it depends on the success rate of the latter in the tender process (bearing in mind that it is the successful bidder only of a given tender which bears the costs

[41] Internal BEIS assumption.

associated with running it). For illustration, as an extreme upper bound, it can be assumed that new entrants are successful bidders in all tender rounds and, therefore, Ofgem's estimated 1% tender cost is fully passed on to new entrants (Table 10). Based on the offshore experience, new entrants are then assumed to recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above. Any bidder that is not successful would not be subject to the recovery of tender costs from the body appointed by Secretary of State: only individual party bid costs would be incurred, which have not been quantified due to lack of evidence.

Table 10: Estimated Tender Costs (Ofgem/appointed body pass through) (2018/19 prices)

	Annual	32 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£6m every other year	£18m
Scenario 3	£6m per year	£31m
Scenario 4	£11m every other year	£36m
Scenario 5	£11m per year	£63m

Note: All estimates are rounded and these costs and those in Table 8 are mutually exclusive.

98. **Potential increased expenditure on transmission assets (transfer)**: If a new entrant is appointed as successful bidder, that new entrant will incur the costs of that asset (although those costs will be more efficient as a result of the new competitive pressures on them). At the same time, the new entrant would receive the revenue stream on the asset and therefore would gain overall by earning the return on the asset.

99. The increased expenditure on assets represents a **transfer within the 'producer' group** (incumbent TOs and new entrants), because any increased expenditure by new entrants under the 'Policy Option' (with more efficient costs) is more than offset by a reduction in status-quo expenditure from incumbent TOs (set out in the benefits section). At the same time that incumbent TOs benefit from less expenditure on assets, they would not receive the revenue stream on the asset and therefore will overall be worse off by losing the return on the asset (set out in the 'generators/suppliers and ultimately end-consumers' section above). This transfer of asset costs (and returns) has not been quantified as it depends on the success rate of new entrants in the tender process.

100. **Costs due to delay risk**: There is a risk that projects could be delayed due to the time taken to run a tender. For new entrants this is a delay compared to the timings of an asset built by incumbent TOs under 'Do Nothing'. This would have implications for asset costs. As set out in the 'generators/suppliers and ultimately end-consumers' section above, the quantifications in this IA assume that Ofgem's framework will prevent any delays from occurring.

2.1.5 Additional costs to the body running the tenders under the Policy Option

101. **Set-up costs**: The body running the tenders incurs costs setting up the competitive process, including on the development of policy, legal and operational frameworks (including the modification of codes and standards) and structures needed to run tenders. Ofgem estimates these costs to be between £2m-£3m (2013/14 prices). For the purposes of this IA, a conservative estimate of £3m has been chosen.[42] As set out above, these costs are assumed to be directly recovered from the ESO. It therefore constitutes a direct cost to business. In future some costs

[42] The £3m in 2013/14 prices – this is equivalent to £3.3m in 2018/19 prices, and it is this latter figure which is used in the IA.

associated with the setting up of the scheme may be recovered through the actual tender costs, which are recovered from the successful bidder in the tender.

102. **Tender costs**: Ofgem incurs costs when running an individual tender, on items such as the staff and resources required to design the tender process, to evaluate bids, and to ensure that appointed licensees meet their obligations. The costs to this body of running a tender are assumed to be 1% of the asset value, as explained by the assumption above. In reality, this will vary by project and tender round, but 1% represents an appropriate long run average and is based on Ofgem's experience to date. There may be some efficiency savings gained by grouping projects together, but in this IA an upper bound cost estimate has been assumed. Table 11 sets out the tender costs across scenarios. These costs are partially offset by a reduction in regulatory costs for the body appointed by the Secretary of State to run tenders. However, as set out above, Ofgem does not have a separate estimate for these costs. Therefore, the estimates of net cost to this body are high/ conservative.

103. It is important to note that a 'high value' criterion minimises the relative costs of tendering. A 'new' and a 'separable' criterion minimises interfaces and therefore the ongoing tender costs associated with more parties.

104. The appointed body recovers its tender costs from successful TOs, which in turn are assumed (based on the offshore experience) to recover these costs from generators and suppliers as set out in the 'Set-up/Tender/Bid costs (of successful bidders) (TO pass through)' section above.

Table 11: Estimated Set-up/Tender Costs (2018/19 prices)

	Annual*	32 Year Period (PV)
Scenario 1	£0m per year	£3m**
Scenario 2	£6m every other year	£21m
Scenario 3	£6m per year	£34m
Scenario 4	£11m every other year	£39m
Scenario 5	£11m per year	£66m

* The annual figures exclude the appointed body's set-up costs of £3.3m as these are transitional, one-off costs.
** In Scenario 1, the appointed body's set-up costs are fully recovered through the licence fee (paid by the ESO) (direct cost). The ESO passes these costs through to generators/suppliers, which ultimately pass them through to end-consumers. In all other scenarios, set-up costs are likely to be recovered through a combination of the licence fee (direct cost) and the successful bidder (direct cost), who will also pass these costs on to generators/ suppliers and ultimately to end-consumers.
Note: All estimates are rounded.

2.2 Additional benefits (monetised / non-monetised) as compared to the 'Do Nothing' option

2.2.1 Additional benefits to generators, suppliers and ultimately end-consumers under the Policy Option

105. **Cost savings through competition**: Extending competitive tendering to some onshore transmission assets significantly benefits generators and suppliers (and ultimately end-consumers) by addressing various market failures present under 'Do Nothing'.

106. Firstly, generators, suppliers and consumers benefit because new parties are able to enter the market (barriers to entry that exist under 'Do Nothing' are removed) and there is increased competitive pressure on all operators. This drives:

- **Innovation**. New parties could be invited to present designs, manage the supply chain and operate the transmission assets. Current incumbents are encouraged to seek savings and produce innovative approaches to delivering and maintaining assets. Innovation may also occur in the technical, commercial and financial space.
- **More efficient and innovative procurement practices** and, therefore, more efficient pricing.
- **Access to new and more diversified sources of labour and capital** as competition widens the pool of transmission owners and investors. This has the benefit of increasing the exposure of financing costs to competitive pressure, and in driving innovation.
- **Increased diversity in the industry** which increases the sources of information that Ofgem can use to benchmark[43] cost submissions. This helps to improve the regulation of all transmission projects, not only those that are subject to competition.
- **More timely delivery** of transmission assets through the deepened incentives on construction.
- **Widening of expertise** in different areas of the network and **potential widening of investment activity** in other areas of the industry.

107. Secondly, generators, suppliers and consumers benefit because competitive pressures in the market allow better cost discovery and therefore a reduction in imperfect information. Under 'Do Nothing', Ofgem does not have access to the same level of information as the companies it regulates, an information asymmetry which can impede Ofgem's evidence base and ability to act in the interest of consumers. Although price controls represent an effective method of controlling costs, competitive pressures under the 'Policy Option' are likely to be more effective in some circumstances through revealing the true and more efficient costs of TOs which will, therefore, address the information asymmetry between the regulated company and Ofgem, should Ofgem be the appointed body by the Secretary of State to run the tenders. This is likely to improve Ofgem's assessment of the efficiency of companies' total costs.

108. It is very likely that competitive tendering will bring about efficient prices more quickly than negotiations and price reviews as part of a price control. While incumbent TOs do engage with the supply chain by running tenders for construction of transmission assets, Ofgem is only presented with a single source of information and no choice over which party owns and operates a particular asset. Competitive pressure will bring increased diversity in the industry, which will increase the sources of information that Ofgem (should it be the body appointed by the Secretary of State to run the tenders) can use to benchmark cost submissions, thus helping to improve the regulation of all transmission projects, not only those that are subject to competitive tendering.

109. There are three ways in which cost savings filter through to consumers. First, savings in the form of lower TNUoS charges are passed through to generators (23%) and suppliers (77%)[44]. Second, the cost savings felt by generators can be passed to end-consumers in the form of lower wholesale prices (if it affects price setting plants) or through lower clearing prices in the Capacity Market. Third, in the case of some low carbon generators, cost savings can be passed to consumers through lower clearing prices in Contract for Difference allocation rounds and therefore potentially more low carbon generation uptake within the Control for Low Carbon Levies, which would lead to lower emissions (a benefit to society). The cost savings that fall to suppliers are assumed to be passed to end-consumers through lower network charges on customer bills. In the first instance any cost savings are experienced by the incumbent TOs and new parties (set out in the relevant sections below).

[43] 'Benchmarking', is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.

[44] National Grid ESO, 'Final TNUoS Tariffs for 2021-22 – Report (updated 04022021)', published January 2021, p. 29, https://www.nationalgrideso.com/document/186176/download

2.2.2 Level of savings to generators, suppliers and ultimately end-consumers under the Policy Option

110. In order to estimate approximate additional cost savings from extending competitive tendering to some onshore transmission assets, this IA relies on the approach adopted in Ofgem's SPV model[45] and on the offshore transmission asset experience, as assessed in the CEPA report on OFTO Tender Rounds 2 and 3[46]. For the purposes of this IA, cost savings are estimated against a price control counterfactual where construction and operation of the transmission asset is onshore TO-led (Counterfactual 3). This counterfactual is the most comparable to the 'Do Nothing' option, as well as being the conservative counterfactual.

111. The analysis in the CEPA report focuses on cost savings in NPV terms, i.e. savings over the economic life of the asset. The report argues that due to competitive pressures the costs borne by consumers will be driven down as the true cost of the asset is revealed and pricing becomes more efficient. The report assumes that this happens faster than might have taken place under the price control review process.

112. Note that for the purpose of this IA, potential tax savings have not been considered due to lack of a suitable counterfactual – in the CEPA report they were derived using a simplified approach devised for OFTOs which is unlikely to be applicable for onshore assets.

113. The CEPA report sets out that against Counterfactual 3 the benefits to society for the first three tender rounds of the OFTO regime are estimated to be £820-£1,060m (NPV excluding tax),[47] broken down into operating (£560-£800m, NPV)[48] and financing (£340m, NPV)[49] cost savings. The report also sets out the financing and operating cost assumptions, from which these figures are derived.

114. This IA uses a set of operating cost 'pathways' to estimate the range of possible operating cost savings that would be expected to materialise under increased competition. These have been derived from the CEPA report on OFTO Tender Rounds 2 and 3 (shown in Chart 1 below) and show the possible operating cost 'premia' versus an incumbent bidder. The first set (Table 12 below, central pathways 4-6, also see orange lines in chart 1) represents the potential operating cost savings versus a price control counterfactual (which is equivalent to 'Do Nothing' in our analysis) under Tender Rounds 2 and 3.[50] These are more conservative than pathways 1-3, the latter of which were derived from OFTO assets that were tendered as part of Tender Round 1.[51] The CEPA report provides several reasons for this – such differences in project size between tender rounds – and suggests that the lower Opex savings achieved under Tender Rounds 2 and 3 is evidence of the beneficial impact of the contestable OFTO programme, in which successive bidding rounds support increasingly refined price discovery.[52]

115. Thus, pathways 1-3 represent the (larger) Opex savings that could be achieved in a sector that has not previously been subjected to competitive pressures, whereas the more modest Opex savings range of pathways 4-6 represents a sector that has already been subjected to some

[45] Ofgem, 'Update on Extending Competition in Transmission and Impact Assessment', published September 2018, https://www.ofgem.gov.uk/publications-and-updates/update-extending-competition-transmission-and-impact-assessment

[46] https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[47] 2018/19 prices. Original figure of £770m – £990m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[48] 2018/19 prices. Original figure of £520m – £745m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[49] 2018/19 prices. Original figure of £315m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[50] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, pp. 33-34

[51] Pathways 1-3 can be derived using the average of the 'low' and 'high' pathways and the preferred bidder levels presented in CEPA/BDO analysis of TR1 – see chart for counterfactuals 3 & 4, p.98 of CEPA/BDO, 'Evaluation of OFTO Tender Round 1 Benefits', published May 2014, https://www.ofgem.gov.uk/ofgem-publications/87717/cepabdotr1benefitsassessmentfinalreport.pdf

[52] CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', published March 2016, https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits, p. 21

form of competitive pressure and price discovery. One could argue that it would be more appropriate to use pathways 1-3 for our analysis, as the onshore assets we are trying to capture in have not yet been subjected to such competitive pressures. However, our analysis uses the more conservative pathways from the CEPA report (pathways 4-6) in order to control for several important factors that could partly limit the benefits of increased competition in the onshore network:

a) **Differences in savings potential**: there is some uncertainty around whether the range operating cost savings represented by the premia in pathways 1-3 are fully applicable to onshore assets, as there are some differences between the OFTOs and the onshore network generally. This is especially the case in terms of scale and the underlying risk profiles – OFTOs have to date been point to point connection wires rather than a complex network and thus have relatively simple Operation and Maintenance contracts. The onshore transmission network on the other hand tends to be more complex – the increased complexity in the onshore network could mean a materially different risk profile that could dampen appetite for investment, competitive pressures and thus the overall savings potential.

b) **Fixed costs**: there is some evidence that the operating costs as a percentage of FTV in Tender Rounds 2 and 3 decreased compared to Tender Round 1 as a result of relative project size (assets under TR2/TR3 tended to be larger than in TR1). Therefore, it looks as if some of the underlying Opex consisted of fixed costs. Evidence from a 2016 Frontier Economics study also supports the view that Opex savings from competition could be dependent on the size of tendered assets.[53]

c) **Economies of scale**: the incumbent TOs could benefit from existing economies of scale, since some of the fixed operating costs can be divided across their relatively large portfolio of assets. They may therefore have a natural advantage that may partially offset the benefits of competition.[54]

116. This IA uses the more conservative pathways 4-6 to estimate the range of potential operating cost savings from competition in order to reduce the risk of overstating the benefits that could be realised from increased competition in the onshore network. These results of using these pathways are presented in Table 14.

117. We have also decided to include an additional set of sensitivities around operating cost savings in order to control for the possible impact of asset size on operation cost savings – these new 'pessimistic' versions of pathways 4-6 are based on evidence from Frontier Economics' study on the benefits of Ofgem's proposed 'late' CATO model.[55] The paper presents a range of possible operating cost savings that could be realised in a competitive context versus a 'National Grid project specific' counterfactual, where infrastructure is delivered by National Grid alone (which is broadly comparable to this IA's 'Do Nothing' scenario). The paper shows that operating cost savings could be dependent on asset size – ranging from 1% to 1.6% of the value of the asset – **with the lower range (1%) being applicable to assets valued at £100m**.[56]

118. However, it is not clear from the report to what extent these savings materialise over the lifetime of the asset. It is unlikely that the 1% saving is a premium that materialises over the entire lifetime of the asset – this IA assumes that Ofgem could drive down operational costs under the 'Do Nothing' scenario, though likely at a slower rate than under increased competition. Therefore, we have constructed a new set of 'pessimistic' pathways based on CEPA's pathways 4-6 – the

[53] Frontier Economics, 'A cost benefit analysis of the potential introduction of competitively appointed transmission operators', published January 2016, https://www.ofgem.gov.uk/ofgem-publications/98418/ngresponseappendix2fronteireconomicsrpt-catocba-080116-final-pdf, p. 53

[54] *Ibid*., p. 41

[55] Ofgem, 'Quick Guide to the CATO Regime', published November 2016, https://www.ofgem.gov.uk/publications-and-updates/quick-guide-cato-regime-november-2016

[56] Frontier Economics, 'A cost benefit analysis of the potential introduction of competitively appointed transmission operators', published January 2016, https://www.ofgem.gov.uk/ofgem-publications/98418/ngresponseappendix2fronteireconomicsrpt-catocba-080116-final-pdf, p. 53

difference being that the starting premium is at **1%** rather than **1.6%** (see table 13 below, also see blue lines in chart 1). The relative trajectory of these 'pessimistic' pathways is identical to that of CEPA's pathways 4-6 – i.e. in years 6-10, the premia of pathways 4 and 5 are at ~70% of their value in year 1-5, in years 11-15 they are at ~35% etc. 100. These pathways thus represent a pessimistic scenario where operating cost savings from the introduction of competition in onshore networks are more limited than envisaged. The results of using these pessimistic pathways are presented in Table 15.

119. Table 12 below sets out the three pathways for operating cost assumptions used in the CEPA report, expressed as the difference between operating costs for Counterfactual 3 and the assumed preferred bidder under the OFTO regime. Operating costs are expressed as percentage of the final transfer value. This IA assumes that the final transfer value is equivalent to the capex of the project.

Table 12: Opex CENTRAL case – Operating cost savings assumptions (% of final transfer value)

	'Pathway 4' – Central	**'Pathway 5'** – Low	**'Pathway 6'** – High
Difference between Counterfactual 3 and the preferred bidder	1.6% (Years 1-5) 1.1% (Years 6-10) 0.6% (Years 11-15) 0.6% (Years 16-20)	1.6% (Years 1-5) 1.1% (Years 6-10) 0.6% (Years 11-15) 0.0% (Years 16-20)	1.6% (Years 1-5) 1.6% (Years 6-10) 1.6% (Years 11-15) 1.6% (Years 16-20)

120. Using these operating cost assumptions, central, low and high cost saving scenarios can be established. The average of these represents the average savings from each asset over an assumed 20-year period of operation.

Table 13: Opex PESSIMISTIC (sensitivity) – Operating cost savings assumptions (% of final transfer value)

	'Pathway 4' – Pessimistic Central	**'Pathway 5'** – Pessimistic Low	**'Pathway 6'** – Pessimistic High
Difference between Counterfactual 3 and the preferred bidder	1.0% (Years 1-5) 0.7% (Years 6-10) 0.3% (Years 11-15) 0.3% (Years 16-20)	1.0% (Years 1-5) 0.7% (Years 6-10) 0.3% (Years 11-15) 0.0% (Years 16-20)	1.0% (Years 1-5) 1.0% (Years 6-10) 1.0% (Years 11-15) 1.0% (Years 16-20)

121. It must be stressed that the 'pessimistic' pathways (table 13) represent an extreme scenario where all tendered eligible assets in the pipeline are valued **~£100m** – thus leading to lower than expected operating cost savings. Such a scenario is extremely unlikely, as large-scale transmission projects are often worth many hundreds of millions of pounds.

122. Therefore, the estimates derived from the 'pessimistic' versions of pathways 4-6 have been used for sensitivity purposes only and have **not** been included in the main table of results (Table 2). Government believes that the inclusion of the 'pessimistic' pathways in the range of results risks significantly understating the benefit to society that can be gained from increased competition. The estimates presented in this IA include several other sensitivities that already factor in optimism bias – i.e. the use of CEPA's pathways 4-6 instead of the more optimistic pathways 1-3 and the inclusion of a scenario where asset construction costs increase by 10% as a result of a poorly designed competition. The latter scenario is very unlikely to materialise, but it is necessary to include due to the lack of concrete data on construction cost savings. The

data on operating cost savings on the other hand is much more robust as it is based on extensive data and analysis of the OFTO experience.

123. Therefore, the central range of estimated benefits will only use the results from table 14 – the results of the 'pessimistic' pathways (table 15) are only presented for illustrative purposes. The impact of this sensitivity is also shown in chart 4. As an illustration, the use of the 'pessimistic' pathways reduces the lower bound of the net benefit to society under the central scenario (pipeline scenario #3) by ~£200m – from a range of **£300m – £500m** down to **£100m – £500m**. In the very unlikely event that all tendered assets are no larger than **~£100m** in value, the associated operating cost savings – though much reduced compared to the central case – still result in a large net benefit to consumers, to the tune of hundreds of millions of pounds (see chart 4).

124. Thus, the savings calculated using pathways 4-6 (non-pessimistic) represent the central case of operating cost savings across all pipeline scenarios. The range of operating cost savings under the 'central case' pathways 4-6 is shown in Table 14.

125. This IA assumes that all operating cost savings are passed on to consumers (Tables 14 & 15).

Table 14: Estimated Operating Savings through Competition over 32 years (2018/19 prices) – using pathways 4-6 (Opex CENTRAL case)

	Annual*	32 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£20m per year	£280m
Scenario 3	£35m per year	£480m
Scenario 4	£38m per year	£550m
Scenario 5	£65m per year	£960m

Note: All estimates are rounded;
*Average annual estimate over the capacity lifetime (25 years)

Table 15: Estimated Operating Savings through Competition over 32 years (2018/19 prices) – using pathways 4-6 (Opex PESSIMISTIC sensitivity)

	Annual*	32 Year Period (PV)
Scenario 1	£0m per year	£0m
Scenario 2	£12m per year	£170m
Scenario 3	£20m per year	£300m
Scenario 4	£25m per year	£340m
Scenario 5	£40m per year	£600m

Note: All estimates are rounded;
*Average annual estimate over the capacity lifetime (25 years)

126. In addition to operational savings, the OFTO regime saw important financing cost savings (£340m, NPV).[57] It is difficult to estimate potential financing cost savings for onshore competition, given that the fact that bidders will be taking on construction risk of the asset means that the risk profile is very different. It is also hard to predict a likely cost of capital for onshore projects for new entrants because financiers have never funded them to engage in these types of projects before. However, as is the case with large investments in other sectors, refinancing is likely to take place post-construction which would almost certainly lower the cost of capital substantially (from its pre-construction level). Given these uncertainties, the margin for error for calculating the potential financing cost savings is large; therefore, this IA does not attempt to quantify it.

127. Tenders in offshore networks have so far only been run for the right to operate an asset. Tenders for onshore network assets would however almost certainly be run for the right to operate *and* construct an asset. In principle, it is most likely that competition for construction would bear down on costs, which could represent a further saving for consumers. Given the lack of evidence from the offshore experience, this IA draws on different evidence to quantify the impact of the 'Policy Option' on construction costs.

128. To estimate capital savings, we use evidence from Ofgem's SPV model. Analysis conducted by Ofgem assumes construction cost savings can amount to **10%** of the value of the asset for an efficiently run competition.[58] The SPV model assumes that the tender would be run by the incumbent TO. Due to the associated incentive risks, the model includes a sensitivity whereby construction costs can increase by up to 10% due to inefficient implementation by the incumbent. This IA assumes that tenders would be run by an independent party which is incentivised to ensure a successful and efficient tender – this would be expected to reduce the risk of an increase in construction costs compared to the SPV model. However, the sensitivity around construction costs is kept in this IA due to the relative dearth of real-world data on the benefits of Ofgem's SPV model.

129. As a sensitivity, we have included two further Capex savings scenarios where the capital saving from competition is **0%** (i.e. no net benefit) and **-10%** for a poorly managed competition. This sensitivity aims to account for the increased construction risks that could be borne by new entrants versus an incumbent TO – though it must be stressed that the latter scenario (of a 10% increase in construction costs) is highly unlikely, as the tenders would be run by an independent party that is incentivised to ensure a successful and efficient tender. We apply these assumptions to our scenarios as described in Table 16. It is important to note that the savings (costs) won't all materialise in the year of construction. Instead, these are spread gradually over a longer time period and are passed on to consumers via reduced (increased) network charges using Ofgem's Allowed Revenue approach, in which the capital costs of assets are depreciated over a 45-year period.

[57] 2018/19 prices. Original figure of £315m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

[58] Ofgem, 'Hinkley-Seabank project: minded-to consultation on delivery mode', published January 2018, table 3.3, https://www.ofgem.gov.uk/ofgem-publications/127841, p. 28

Table 16: Capital cost savings assumptions (% of capex of the project)

	Capex savings scenario		
	Poorly managed competition	**No net benefit**	**Efficiently run competition**
Scenario 1	-10%	0%	10%
Scenario 2	-10%	0%	10%
Scenario 3	-10%	0%	10%
Scenario 4	-10%	0%	10%
Scenario 5	-10%	0%	10%

130. The evidence for construction cost savings from the SPV model is not as robust as the evidence from the OFTO experience considered for operating costs as it has not arisen from the revealed information of a competitive process. Nonetheless, as the evidence used in the evaluation of the delivery model for a new, high-value and separable onshore transmission asset it constitutes the most relevant and best evidence available at the time of writing. Feedback from Ofgem has clearly indicated that the approach used in the SPV model is the most appropriate one for this analysis.[59] In not including it, this IA would risk being too conservative in the size of the savings that the policy option may realise.

131. The construction cost savings assumed by the SPV model are supported by anecdotal evidence from outside the UK. Examples include the application of competitive tendering to transmission in the "Fourth Line" project in Buenos Aires, Argentina, which led to 44% reduction in total costs.[60] In February 2017, the Energy Networks Association published a report detailing examples where early model competition in high value transmission projects had led to significant cost savings in the rage of 10%-60%.[61] These figures should be treated with caution, given the uncertainty around the counterfactuals used and thus their limited applicability to the GB electricity market. However, these studies do suggest that cost savings and thus benefits to consumers from increased competition in otherwise monopolised markets can be substantial.

132. This IA assumes that all capital cost savings are passed on to consumers (Table 17).

[59] Based on internal discussions with Ofgem (September 2019).

[60] Littlechild and Skerk, (2004) 'Regulation of transmission expansion in Argentina Part I: State ownership, reform and the Fourth Line', p. 60.

[61] Ofgem, 'Developing early models for introducing competition in onshore electricity transmission networks,' published February 2017, https://www.ofgem.gov.uk/system/files/docs/2017/04/ena_working_group_report_16_feb_2017.pdf, pp. 65-73.

Table 17: Estimated Capital Cost Savings through Competition over 32 years (2018/19 prices)

	Poorly managed competition (-10%)		No net Benefit (0%)		Efficiently run competition (10%)	
	Per project (undiscounted) over lifetime	*32 Yr Period (PV)**	*Per project (undiscounted) over lifetime*	*32 Yr Period (PV)**	*Per project (undiscounted) over lifetime*	*32 Yr Period (PV)**
Scenario 1	£0m	£0m	£0m	£0m	£0m	£0m
Scenario 2	-£25m	-£60m	£0m	£0m	£25m	£60m
Scenario 3	-£25m	-£100m	£0m	£0m	£25m	£100m
Scenario 4	-£50m	-£115m	£0m	£0m	£50m	£115m
Scenario 5	-£50m	-£200m	£0m	£0m	£50m	£200m

Note: All estimates are rounded; these costs are included in Table 2 indirectly – by reducing the benefits (for a poorly managed comp.). *Capital cost savings (costs) do not all materialise on the year of construction. Instead, these are spread gradually over a longer time period and are passed on to consumers via reduced (increased) network charges using Ofgem's Allowed Revenue approach, in which the capital costs of assets are depreciated over a 45-year period.

133. This IA assumes that all savings are passed on to consumers (Table 18). These represent stylised ranges of cost savings, which are mainly aimed at providing a sense of scale rather than a precise assessment of what benefits from competition would be.

Table 18: Estimated Cost Savings through Competition over 32 years (PV, 2018/19 prices)

	Poorly managed competition (-10%)	No net Benefit (0%)	Efficiently run competition (10%)
Scenario 1	£0	£0	£0
Scenario 2	£0.2bn	£0.3bn	£0.4bn
Scenario 3	£0.4bn	£0.5bn	£0.6bn
Scenario 4	£0.4bn	£0.6bn	£0.7bn
Scenario 5	£0.8bn	£1.0bn	£1.2bn

Note: All estimates are rounded.

134. **Lower cost of regulation under the price control (TO pass-through):** Set-up, tender and bid costs will be partially offset by lower costs of price control regulation. These lower costs arise from the fact that there would no longer be a need for the TO to conduct a project assessment under the terms of the price control[62]. This will ultimately benefit consumers (indirect benefit). The benefit is initially felt by the incumbent TOs (captured in the sections below). The appointed body passes any reduced cost of regulation under the price control mechanism on to the ESO, which is considered a direct benefit. The ESO will pass these savings on to generators (14%) and suppliers (86%) through lower TNUoS charges (indirect benefit). Generators pass these savings through to end-consumers either in the form of lower wholesale prices (if price setting plants are affected) or in the case of low carbon plant in the form of lower clearing prices in Contract for Difference allocation rounds and therefore potentially more low carbon generation uptake within the Control for Low Carbon Levies, which if it materialised would lead to lower emissions (a benefit for society). This IA assumes that suppliers pass these savings through to end-consumers through lower network charges on customer bills.

[62] Under 'Policy Option', Ofgem determine the needs case.

135. As set out under 'Do Nothing', Ofgem does not have a separate estimate of these reduced costs under the price control mechanism. The costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial. Therefore, because these costs cannot be quantified, the net costs estimated in this IA under the 'Policy Option' might represent a conservative estimate.

2.2.3 Additional benefits to incumbent TOs under the Policy Option

136. **Lower cost of regulation under the price control**: Incumbent TOs benefit from lower costs of price control regulation, as they will not have to submit a project assessment submission under the price control for a project which will be competitively tendered. As set out under 'Do Nothing', Ofgem does not have a separate estimate for the reduced costs of regulation under the price control mechanism. Therefore, the net costs estimated in this IA represent high estimates. Incumbent TOs pass any cost reductions through to end-consumers as set out in the 'Lower cost of regulation (TO pass-through)' section above.

137. **Lower cost of regulation under the price control (Ofgem/appointed body pass-through):** Ofgem benefits from a reduced cost of regulation under the price control, because it no longer needs to undertake a project assessment under the price control. It passes these savings on to the respective incumbent TO. As set out under 'Do Nothing', Ofgem does not have a separate estimate for the reduced costs of regulation under the price control mechanism. Therefore, the net costs estimated in this IA represent high estimates. Incumbent TOs pass any cost reductions through to end-consumers as set out in the 'Lower cost of regulation (TO pass-through)' section above.

138. **Lower expenditure on transmission assets**: Reduced barriers to entry in the transmission market, and an increased number of parties in the market, will create competitive pressure and better cost discovery. Incumbent TOs will consequently spend less on assets due to either:

a) not being appointed as the successful bidder in situations where the asset would otherwise have fallen into their region (case 1, transfer); or

b) being appointed as successful bidder but at a more efficient asset cost (case 2).

139. The lower expenditure under case 1 represents a **transfer within the 'producer' group** (incumbent TOs and new entrants) as any reduced expenditure by incumbent TOs is partially offset by an increase in expenditure from new entrants (who would anyway have more efficient costs due to competitive pressures, as set out in the cost section). In this case, the incumbent TO would not receive the revenue stream and, therefore, the return for the asset (as set out in the cost section). In turn, the potential increase in expenditure for new entrants is offset by their receipt of a revenue stream. These transfers have not been quantified as they depend on the incumbent TOs submitting a bid and, if they bid, their success rate in the tender process.

140. Expenditure under case 2 is reduced because the incumbent TO has been appointed as successful bidder, but competitive pressures mean that their costs are more efficient.

141. The 'Assumptions and Risks' section below discusses the treatment of preliminary works in the analysis.

2.2.4 Additional benefits to the ESO under the Policy Option

142. There are no additional benefits for the ESO under the 'Policy Option'.

2.2.5 Additional benefits to new entrants under the Policy Option

143. **Market entry**: New players will benefit from the policy option because it creates a route to market.

144. **Potential gain of returns on assets (transfer)**: An increased market share for new entrants means that they should benefit from a return on any assets they own in the form of a revenue stream, provided that actual asset delivery costs are not eroding the returns.

145. The potential return for new entrants represents a **transfer within the 'producer' group** (incumbent TOs and new entrants), because it can only occur when an incumbent TO loses the return (given they would not receive the revenue stream, though not incur the asset cost). For simplicity, this IA assumes that the loss in return for incumbent TOs is offset by the gain in return for new entrants. Therefore, the return to the 'producer' group is assumed to be unchanged. While new entrants incur a lower capital expenditure, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption on returns being unchanged is a fair one.

146. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how revenue streams are set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

147. Note that these transfers have not been quantified as they depend on the new entrants' success rate in the tender process.

2.2.6 Additional benefits to Ofgem/the appointed body under the Policy Option

148. **Lower cost of regulation under the price control (directly passed through)**: Tender costs will be offset by reduced costs of regulation under the price control. The reduced cost of regulation relates to the reduced costs of undertaking a project assessment for projects covered by the price control mechanism under 'Do Nothing', but deemed eligible for competitive tendering in the 'Policy Option'. Ofgem or the appointed body will pass any reduced cost of regulation directly on to the ESO (direct benefit), which will then pass these savings on to generators/ suppliers, and ultimately end-consumers, as set out in the 'Lower cost of regulation (TO pass-through)' section above. Ofgem does not have a separate estimate for these reduced costs. However, as the costs of conducting price controls and assessing the needs cases for specific projects within the price controls are non-trivial, it is likely to offset the additional tender costs to a certain degree. Therefore, the net costs estimated in this IA represent high/conservative estimates.

149. **Reputation and confidence benefit**: Ofgem is likely to experience a reputational benefit from being better able to protect existing and future consumers. Furthermore, introducing competition would mitigate the current information asymmetry that exists between Ofgem and the TOs, the existence of which suggests that Ofgem is currently inhibited from ensuring consumers are provided the best value for money. Confidence in the regulator is, therefore, increased when competition is applied, if Ofgem is appointed by Secretary of State to run tenders.

Note on Net Cost / Benefit Estimates

150. Table 1 (found in the 'Results of the Cost Benefit Analysis of the proposed intervention' section of this IA) summarises the estimated direct net monetised benefit to business in NPV terms across the five scenarios. The scenarios demonstrate the likely scale of potential costs and benefits. Note that not all costs and benefits could be quantified (as set out in the detailed sections above).

151. The quantified direct net cost to business is in the range of £3m to £225m (PV) over the appraisal period of 32 years, with a central estimate of £115m (PV). Note that while some businesses, namely TOs and new entrants, incur the direct expenditure, they will pass these costs onto other businesses, namely generators and suppliers (indirect cost), which ultimately pass them on to end-consumers, which includes business consumers (indirect cost).

152. The net benefit to society is in the range of **-£3m to £1.0bn** (NPV over 32 years) (Table 2). All of these costs and benefits will be incurred as a consequence of secondary legislation. None of these costs or benefits relate directly to the primary legislation associated with this IA. The net benefit to society under the central scenario (pipeline scenario #3) is estimated to range between **£300m – £500m** (NPV over 32 years).

Assumptions and Risks

153. For the quantifications in this IA, various assumptions have been made. These are set out below. Most importantly, the monetised impacts estimated in this IA aim to provide a sense of scale of benefits and costs, rather than to provide definite predictions of likely costs and benefits.

154. **Cost savings due to competition:** The benefits section above sets out how Government has derived cost savings in this IA. Much of this analysis relies on a comparison with an independent evaluation of the results of the first three rounds of offshore tenders carried out for Ofgem by CEPA. Several caveats need to be borne in mind:

a) While new entrants are likely to incur a lower capital expenditure than incumbent TOs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. However, as is the case with big investments in other sectors, refinancing is likely to take place post-construction, which would almost certainly lower the cost of capital substantially (from its pre-construction level).

b) Savings in the offshore regime were realised in part by offshore generators bidding for very low maintenance costs in an attempt to maintain control over their own assets. Arguably, because there is no corresponding generation asset to attempt to control in an onshore competition, onshore bidders will not be incentivised to bid for such low maintenance costs, and overall savings may be lower. However, savings could be seen in construction delivery, and there have been genuinely innovative approaches to asset maintenance in the offshore regime which has brought about savings.

c) Two reports by CEPA analysed the level of savings realised in delivering the first 15 offshore licences. A further 6 licences have been awarded since the CEPA reports were published, and an additional 25 projects are on the pipeline. Given that these have not yet been analysed in a report similar to the CEPA reports, the analysis in this IA does not factor in any changes that these additional licences would make to achievable operating cost savings.

d) Government recognises, as indicated in the CEPA report, that there are limits to the extent to which lessons can be drawn from the CEPA report conclusions for the onshore electricity transmission network, given that the outcomes demonstrated in the report are context - and time - specific. However, Government believes that the onshore projects expected to be captured by competitive tendering share similarities with offshore projects – being new, high-value, and separable – and, therefore, comparisons are reasonable. It is also the case that this report, which estimates the savings realised by introducing competition into the offshore electricity transmission network, is the best indication of the operating savings likely to be realised by introducing competition into the onshore electricity transmission network.

155. **Pipeline scenarios:** The IA proposes a future pipeline of eligible projects by analysing historic information on TIRG[1] and TII[2] investments over TPCR4 from 2007/08 to 2012/13. The IA has also considered the levels of investment that have occurred over the RIIO-T1 (under and SWW[3]) and ED1 price control regimes. The IA emphasises the uncertainty surrounding this pipeline and the likelihood that assets will eventually be constructed through competitive

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[1] www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-national-grid-electricity-transmission-and-national-grid-gas-%E2%80%93-overview
www.ofgem.gov.uk/publications-and-updates/riio-t1-final-proposals-sp-transmission-ltd-and-scottish-hydro-electric-transmission-ltd

[2] Ibid.

[3] www.ofgem.gov.uk/ofgem-publications/52669/jul12whvdcdecisionfinal.pdf; www.ofgem.gov.uk/ofgem-publications/84439/finaldecisionletter-kintyrehunterston.pdf; www.ofgem.gov.uk/ofgem-publications/87262/decisiononthe proposedbeaulymossfordreinforcementunderriio-t1strategicwiderworksarrangements.pdf; www.ofgem.gov.uk/ofgem-publications/91977/decisiononourassessmentofthecaithnessmoraytransmissionproject.pdf

tendering in the future. Whilst Ofgem does possess a forecast of projects to be constructed, this forecast is commercially sensitive, and there is no certainty over which of the projects in it would be competitively tendered. To mitigate this uncertainty, this IA considers five investment scenarios over the next 10 years of £0per year, £0.55bn every other year (an undiscounted total of £2.2bn investment over the next 10 years), £0.55bn per year (an undiscounted total of £3.85bn investment over the next 10 years), £1.1bn every other year (an undiscounted total of £4.4bn investment over the next 10 years) and £1.1bn per year (an undiscounted total of £7.7bn investment over the next 10 years). Note that all undiscounted totals account for the first three years being used for scheme set up and the first tender round. £0 per year is considered an extreme lower bound, while £1.1bn per year represents an extreme upper bound. However, if more than £1.1bn per year were to be realised, the additional benefits from competition would outweigh the associated costs. Therefore, in this respect, the IA risks being too conservative in terms of benefits from competition. Discussions with Ofgem have confirmed that the above set of pipeline scenarios are also broadly in line with the potential pipeline of projects under RIIO-T2 that might meet the expected criteria for competition (based on current draft RIIO-T2 business plans).

156. The IA assumes that a set of criteria (new, high-value, separable) will be applied to the pipeline scenarios to select the assets that will be tendered. This represents the best available information at the time of writing this IA. However, the final criteria will be set by the Secretary of State in regulations. Therefore, there is a risk in the level of precision of the final criteria, which reflects the possibility that the investments captured by competitive tendering will change. The fact that the scenarios encompass a wide range of possible outcomes mitigates against this risk.

157. If a tender fails, no bidder is appointed, and a third party who agrees to manage the asset cannot be found, Ofgem intends to enable a ‘last resort’ mechanism. Under this mechanism, a transmission owner will be required to manage the relevant assets for a period of time. This mechanism exists in the offshore regime, but has never been used, because competitions have never failed in this way. This IA assumes that assets would be built by a competitively appointed TO, or eventually transferred to a competitively appointed TO through commercial negotiations, a reasonable assumption given that the offshore scheme has to date always been successful in appointing an owner.

158. **Size of projects:** The investment averages are assumed to cover one or several projects (depending on the ‘high value’ criterion). Because tender and bid costs are expressed in percentage terms, this IA assumes that costs increase in tandem with higher asset values or more projects. The impacts of size or number of projects on tender costs are set out in the tender cost section under the ‘Policy Option’.

159. **Preliminary works**: The incumbent regional transmission licensee or the SO may complete early development work and some preliminary works prior to a tender. The current expected position is that the incumbent regional transmission licensee would undertake these works; however, it is possible that Ofgem would request that the SO carries out these works in future. The nature and extent of these works would depend on the tender model used. If the SO takes on these works, while this may involve a small amount of additional cost for the SO, these costs will be offset by the work no longer undertaken by TOs (transfer within the “Producer” group). These arrangements will be further considered as part of secondary legislation when a detailed framework is developed. This has not been quantified in this IA.

160. **Cost of regulation of projects assumed eligible**: In order to estimate the cost of regulation for potentially eligible projects, it is worthwhile considering the costs faced by other large projects, such as those falling under TIRG, TII or SWW. These include costs associated with eligibility, needs case and project assessment stages. Ofgem estimates that this process takes approximately 12-15 months from the start of the assessment process to a funding decision for

well-evidenced proposals, but it can take upwards of 2 years for many projects.[4] Costs are incurred by both Ofgem and the TOs. As advised by Ofgem, it is not possible to provide an estimate for these costs in isolation. However, the costs of conducting price controls and assessing the needs cases and project assessments for specific projects within the price controls are non-trivial.

161. **Chosen assessment timeframe:** Extending competitive tendering to transmission assets is considered to be a permanent policy change i.e. there is no end-date. Therefore, for the purpose of the quantifications in this IA, pipeline scenarios of network assets coming forward over the next 10 years and their respective savings over a 20-year period have been used. This is in line with the evidence provided by the offshore regime. The appraisal timeframe in this IA in full is therefore 32 years. Choosing a longer time frame magnifies the scale of the costs and benefits; however, the overall conclusion that more competition is beneficial for society is unchanged.

162. **Return on Investment for incumbent TOs and new entrants**: For simplicity, it is assumed that the group of incumbent TOs and new entrants as a whole has unchanged returns between 'Do Nothing' and the 'Policy Option'. While, under the Policy Option, new entrants incur a lower capital expenditure, which might imply higher returns as a percentage of costs, new entrants also face higher cost of capital due to taking on higher risk than an incumbent TO, which can spread the cost of the project over its entire asset base. If the market prices risk appropriately, our assumption that returns are the same across 'Do Nothing' and the 'Policy Option' is a fair one.

163. This assumption needs to be heavily caveated as the exact way in which revenues and costs and therefore returns would develop under a competitive regime depends on various factors. For example, it will depend on how revenue streams are set and whether they will provide more certainty or better returns for investors; it will depend on whether new entrants will be able to deliver projects according to anticipated cost structures as well as incumbent TOs under 'Do Nothing'; and it will depend on whether new entrants are more strongly incentivised to outperform anticipated cost structures as set out at the time of the tender through further efficiency savings or innovation than under 'Do Nothing'.

164. **Bid costs for incumbent TOs and new entrants:** Bid costs include the costs incurred in preparing bids for evaluation, reaching the licence grant and acquiring the asset. Actual bid costs from the offshore regime are commercially sensitive and cannot be used for the purposes of this IA. Instead, this IA uses the findings from the CEPA report, which sets out that successful bidder costs are £75m,[5] or approximately 2.4% of the Final Transfer Value (FTV), over fifteen projects. 2.4% of asset value is likely to be a conservative estimate. Offshore, because generators build the assets that are eventually transferred to the winning bidder, time and resources are spent on due diligence on those built assets, which can substantially add to bid costs. We do not expect this to be the case for onshore (because the competitively appointed party will build their own asset), which means that bid costs may be lower. Further, there will be other avoided onshore costs (such as not having to prepare SWW project assessment submissions), which may reduce the overall size of the bid costs. There is no separate estimate of these avoided costs and they are therefore not quantified in this IA.

165. The cost to each unsuccessful bidder of preparing bids for evaluation has not been quantified because this information is commercially confidential. The total costs of unsuccessful bids in each tender round would also rely on the total number of bidders, which varies across tenders.

166. **Additional interface costs for the SO:** This IA assumes that there are no additional interface costs for the SO. There may be an incremental interface cost associated with adding

[4] https://www.ofgem.gov.uk/ofgem-publications/85263/strategicwiderworksfactsheet.pdf

[5] 2018/19 prices. Original figure of £70m (2014/15 prices) can be found here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

new parties to the network; however, because the SO already interacts with a broad group of industry parties, additional parties would only lead to a marginal increase in cost, which Government estimates to be zero. Industry codes and standards are already in place to manage the relationships between parties and, where necessary, they can be amended to accommodate competitively appointed TOs and to ensure that industry relationships are managed in a constructive and efficient manner.

167. **Tender costs for the body appointed by the Secretary of State to run the tenders:** Ofgem estimates that scheme set-up costs are between £2m-£3m (2013/14 prices). For the purpose of this IA, a conservative estimate of £3.3m (2018/19 price base) spread over two years has been assumed. These costs will occur prior to launching the first tender, regardless of the subsequent volume or frequency of tenders. Costs of running an individual tender, associated broadly with staffing, technology and external advice on legal technical and financial matters, are assumed to be 1% of the asset value. This is based on the offshore experience. In reality, these costs will vary by project and tender round, given that there are some fixed costs associated with running tenders. However, it is expected that these costs will balance out over time and 1%, therefore, represents an appropriate long run average.

168. In place of one large project, several smaller projects could be tendered in a given year, which may either increase the appointed body's administration costs (because they are running several projects) or decrease them (because they are running several projects at once). Consequently, 1% represents an appropriate long-run average and is based on Ofgem's experience to date. For the purpose of this IA, an upper-bound cost estimate has been assumed. It is important to note that these costs would be partially offset by other avoided costs (e.g. Ofgem assessment and processing of SWW project assessment submissions). However, these costs have not been quantified.

Innovation impacts

169. Innovation impacts from increasing competition in the GB onshore network have only been quantified indirectly in this IA. The expected benefits from reduced operating and construction costs would partly be driven by an expanded market which in turn should incentivise market participants to adopt cost saving innovations through the introduction of new services and technologies.

170. The incumbent network operators currently have **monopoly rights** over the planning, construction and operation of all network assets in their respective regions. While network operators already competitively tender certain aspects of their projects, they retain overall control and cost information. This presents a **significant barrier to entry** as it limits the ability of other parties to participate fully in the market, regardless of whether they may be able to deliver assets more efficiently. Limiting the size of the market also limits approaches to procurement, price-reflectivity, financing and construction. The proposed intervention will help to address some of these barriers to innovation via increasing competitive pressures in the market.

171. Depending on the nature of the tenders, new market participants will be invited to present designs, manage the supply chain and operate the transmission assets. Current incumbents will be further encouraged to seek savings and produce innovative approaches to delivering and maintaining assets.

172. Particular attention should be given to the ways in which the policy will diversify the sources of labour and capital, both of which would incentivise innovation. Opening up investment opportunities to new parties allows different sources of labour and capital to enter the industry. Competitive pressure and the involvement of new parties in the market will likely lead to preferential financing costs and drive innovation. On an individual project basis, innovation can result in lower costs and better value for consumers.

173. For example, in financing, Greater Gabbard OFTO was the first UK and second EU project to use the innovative EIB Project Bond Credit Enhancement (PBCE) product[6], reducing the cost of capital and giving value to consumers. In technology development, TC Ormonde OFTO Ltd was awarded funding through the 2014 Network Innovation Competition to develop an offshore cable repair vessel and universal cable joint.[7] This has reduced the cost of offshore maintenance and produced benefits for consumers.

174. Innovation may also occur in the technical, commercial and financial space – these are, however, very difficult to quantify, and have therefore not been monetised in this IA.

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[6] https://www.ofgem.gov.uk/press-releases/ofgem-grants-offshore-transmission-licence-greater-gabbard-wind-farm

[7] https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-competition/transmission-capital-partners

Public Sector Equality Duty (PSED) and Onshore Competition Proposals

175. We have reviewed how the Public Sector Equality Duty[8] (PSED) relates to expanding competition in GB's onshore network. Our assessment is that the proposed intervention does not lead to any discrimination, harassment, victimisation or other prohibited conduct as described under Limb a) of PSED. As set out in this Impact Assessment, we expect competition in onshore electricity networks to lower the costs associated with addressing network constraints. As more electricity network reinforcement will be necessary in order to meet net zero by 2050, lowering the network costs associated with those reinforcements should have the effect of lowering consumer bills, as network investment is funded via consumer bills across GB. We do not expect this to impact negatively on any group with a protected characteristic under the Equality Act 2010 and it should benefit all consumers, regardless of their characteristics and backgrounds.

184. Under limb (b) we consider that the policy may remove or minimise disadvantages connected with particular protected characteristics. Those with protected characteristics may be exposed to higher electricity consumption costs if their consumption is higher. Competition would lower the additional costs necessary for network reinforcement to meet Net Zero, and so the anticipated increase on bills of those with protected characteristics may be less, assuming their consumption is higher than those without that protected characteristic. So the policy may advance equality of opportunity between people who share a protected characteristic and people who do not share it in some circumstances. Given the nature of this policy is to lower bills, we consider the policy is neutral in regard to limb (c) of the PSED –the decision to proceed will have no effect on relations between individuals who share a protected characteristic and people who do not share it.

[8] The PSED is a duty requiring public authorities and others carrying out public functions to have due regard to:

a) Eliminate unlawful discrimination, harassment, victimisation and any other conduct prohibited by the Equality Act 2010;
b) Advance equality of opportunity between people who share a protected characteristic and people who do not share it;
c) Foster good relations between people who share a protected characteristic and those who do not.

Wider impacts

Economic and financial impacts

185. The estimated quantified and non-quantified impacts on consumers and businesses of extending the use of competitive tendering in the GB transmission network are covered in the monetised costs and benefits assessment above. This also addresses the expected impacts on Ofgem. Impacts on small and start-up businesses are captured in the Small and Microbusiness Assessment below.

186. Particular attention should be given to the ways in which the policy will diversify the sources of labour and capital and incentivise innovation. Opening up investment opportunities to new parties allows different sources of labour and capital to enter the industry. Competitive pressure and the involvement of new parties in the market will likely lead to preferential financing costs and drive innovation. On an individual project basis, innovation can result in lower costs and better value for consumers.[9]

187. Increased diversity in the industry also increases the sources of information Ofgem can use to benchmark[10] cost submissions, thus helping to improve the regulation of all transmission projects, and not only those that are subject to competition.

188. More investment in electricity networks may also prompt stronger investment appetite from newer investors.

Social impacts

189. There are no social impacts expected to arise under the 'Policy Option'.

190. Government does not expect any additional impacts of the 'Policy Option' on vulnerable consumers as a subset of GB consumers. However, consumers who have lower incomes will generally see greater relative improvements in the affordability of their electricity compared to 'Do Nothing'. This is because the majority of benefits achieved under the 'Policy Option' will be passed by suppliers to consumers through lower network charges which are a fixed proportion of consumer bills. Consumers in lower incomes tend to have lower energy consumption which means they benefit more from lower fixed charges.

Environmental impacts

191. The proposed 'Policy Option' is unlikely to have any significant environmental impacts. Innovative approaches to delivering and maintaining transmission assets may lead to lower embedded carbon levels. In addition, lower network costs may serve to encourage investment in the energy sector more generally, and this may focus on low carbon generation.

Trade impacts

192. Following this consultation stage IA, we will assess the potential impacts on international trade and investment and demonstrate these impacts in our Final Stage Impact Assessment (if applicable), in consultation with the Department for International Trade (DIT).

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[9] For example, in financing, Greater Gabbard OFTO was the first UK and second EU project to use the innovative EIB Project Bond Credit Enhancement (PBCE) product (https://www.ofgem.gov.uk/press-releases/ofgem-grants-offshore-transmission-licence-greater-gabbard-wind-farm), reducing the cost of capital and giving 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 (https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation/electricity-network-innovation-competition/transmission-capital-partners). This is intended to reduce the cost of offshore maintenance and produce benefits for consumers.

[10] 'Benchmarking' is the process of comparing cost estimates for particular items or activities against real costs incurred at other times or by other parties.

Monitoring and evaluation

193. For any subsequent secondary legislation following on from this measure, we will ensure appropriate and proportionate monitoring, evaluation and review processes are put in place.

Rationale and evidence that justify the level of analysis used in the IA

194. Where possible, impacts of the proposed measure have been quantified and monetised, mainly to provide a sense of scale of the likely impacts. The quantification of pipeline scenarios is stylised due to the uncertainty and market sensitivity around potentially eligible projects in the pipeline. Monetisation draws heavily on the competitive tendering experience for offshore transmission assets (because it is the best available source of data). Sensitivity analysis has been used to demonstrate the uncertainties associated with the assumptions made in this IA.

Small and Microbusiness Assessment (SMBA)

195. There are no small or microbusinesses currently operating in the transmission sector. The current incumbent TOs – National Grid Electricity Transmission, SP Transmission and SHE-Transmission– are large businesses. Operators of offshore transmission assets who secured their licences through the competitive process introduced in 2009 are all Special Purpose Vehicles consisting of consortia of large businesses, such as construction companies or financial institution investors.

196. The policy option proposed here does not introduce any additional burdens on small or micro-businesses. Instead, the policy option lifts a barrier to small- and microbusiness-involvement in the transmission market by opening up the market to new entrants.

197. Small and micro-businesses may see greater relative improvements in the affordability of their electricity compared to 'Do Nothing' than other businesses.

Summary and preferred option with description of implementation plan

198. In 2019, approximately a fifth to a quarter of a typical household electricity bill was made up of the cost of transporting electricity from the place that it was generated to the customer.[11] Bearing down on the costs of developing, improving and maintaining the infrastructure through which electricity is transmitted ensures that customer bills are kept as low as possible.

199. In 2009, Government introduced legislation that enables Ofgem to determine through a competitive process the party that owns and operates offshore transmission infrastructure. It is estimated that between 2009 and 2016, this approach created savings of £460-£800 million.[12]

200. In light of this, Government proposes to enable competitive tendering in other areas of the electricity network, where it and Ofgem judge that a competitive tender could be socially beneficial.

201. Government is proposing primary legislation that would enable implementation of this competitive process through secondary legislation.

202. At the primary legislative stage, there are no immediate monetised costs or benefits. The costs and benefits at the secondary legislation stage have been assessed as far as possible. This assessment is based on stylised assumptions about eligible projects, and estimated costs and savings are based on the offshore experience of competitive tendering and on the

[11] https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill. Estimate based on an average electricity bill for a typical domestic customer of the six large suppliers.

[12] 2018/19 prices. Original figures (2014/15 prices) were in the range of £425-750 million. CEPA, 'Evaluation of OFTO Tender Round 2 and 3 Benefits', tables 6.1 & 6.2, pp. 36-38

assumptions underpinning Ofgem's Special Purpose Vehicle model for onshore transmission competition. This analysis suggests that the proposal should result in a net benefit to society of between **-£3m to £1.0bn** (NPV over 32 years, 2018/19 prices) with a medium scenario of **£300m to £500m**. The estimated impacts will be further analysed at the secondary legislation stage.

Annex A

1. The table below lays out the assumed investment and operational timings for the purposes of this IA. Year 1 and 2 are needed to set up the scheme; the first tender takes place in Year 3; and construction of the first asset begins in Year 4. There are 5 investment scenarios assumed in this IA:

   a) No investment
   b) £0.55bn every other year (an undiscounted total of £2.2bn investment over the next 10 years)
   c) £0.55bn per year (an undiscounted total of £3.85bn investment over the next 10 years)
   d) £1.1bn every other year (an undiscounted total of £4.4bn investment over the next 10 years)
   e) £1.1bn per year (an undiscounted total of £7.7bn investment over the next 10 years)

2. The savings generated by the policy option from each asset are considered over a 20-year time period from start of operation. This is based on the time period used in the offshore regime. This results in an overall assessment period of 32 years.

	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
Construction ► Operation ▼	Asset 1 built	(Asset 2 built)	Asset 3 built	(Asset 4 built)	Asset 5 built	(Asset 6 built)	Asset 7 built
Year 7	x						
Year 8	x	x					
Year 9	x	x	x				
Year 10	x	x	x	x			
Year 11	x	x	x	x	x		
Year 12	x	x	x	x	x	x	
Year 13	x	x	x	x	x	x	x
Year 14	x	x	x	x	x	x	x
Year 15	x	x	x	x	x	x	x
Year 16	x	x	x	x	x	x	x
Year 17	x	x	x	x	x	x	x
Year 18	x	x	x	x	x	x	x
Year 19	x	x	x	x	x	x	x
Year 20	x	x	x	x	x	x	x
Year 21	x	x	x	x	x	x	x
Year 22	x	x	x	x	x	x	x
Year 23	x	x	x	x	x	x	x
Year 24	x	x	x	x	x	x	x
Year 25	x	x	x	x	x	x	x
Year 26	x	x	x	x	x	x	x
Year 27		x	x	x	x	x	x
Year 28			x	x	x	x	x
Year 29				x	x	x	x
Year 30					x	x	x
Year 31						x	x
Year 32							x

Annex B

Index of terms

BEIS: Department for Business, Energy and Industrial Strategy

CATO: Competitively Appointed Transmission Owner

CEPA: Cambridge Economic Policy Associates

CF: Counterfactual

DNO: Distribution Network Operators

ITPR: Integrated Transmission Planning Regulation

NETS: National Electricity Transmission System

NPV: Net Present Value

Ofgem: Office of Gas and Electricity Markets

OFTO: Offshore Transmission Owner

PV: Present Value

SO: System Operator

SWW: Strategic Wider Works

TII: Transmission Investment Incentives

TIRG: Transmission Investment for Renewable Generation

TO: Transmission Owner