Evaluation of OFTO Tender Round 1 Benefits

Prepared for the Office of Gas and Electricity Markets

Final report

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EXECUTIVE SUMMARY

Executive summary

The purpose of the report is to provide an economic evaluation of the Transitional Offshore Transmission Owner (OFTO) regime as applied to Tender Round One projects

- In 2009 the Government and Ofgem introduced a new licensing model, combining aspects of both competition and regulation, to deliver offshore electricity transmission infrastructure in Great Britain (GB).
- Unlike in other jurisdictions, this involves a competitive tender process to appoint new offshore electricity network operators who have the responsibility for operating newly constructed electricity transmission network assets, which connect offshore electricity generation (wind farms) to the shore.
- A consortium of CEPA and BDO[1] was engaged by Ofgem to assess the benefits that may have been achieved from the introduction of this competitive OFTO regulatory framework as applied to the first round of projects tendered under the regime - Tender Round One (TR1).
- This report sets out the methodology that we have used to assess these benefits, our findings on the estimated cost savings that have been realised from applying the OFTO regime to the TR1 projects and how those savings may have been distributed between different parties (that is, consumers and generators) through the funding arrangements for offshore wind and offshore transmission in GB.

Note 1: The majority of the report analysis and its findings have been prepared by CEPA. BDO as part of a consortium have supported CEPA with a review of bids submitted in the TR1 process and the modelling undertaken.

The Transitional OFTO regime applies to those transmission projects that were already in construction or taking steps towards construction

- During the OFTO framework's development, there was recognition that for a number of projects, the offshore generator developer had already started construction or was undertaking steps towards construction.
- The Government and Ofgem therefore developed a Transitional OFTO regime that would apply to those projects that had either awarded construction contracts or started construction works.
- As with the regime that was expected to apply on an enduring basis to all future offshore transmission projects (the "enduring regime"), this involved a tender process to award an OFTO with an offshore transmission licence that provided the right to receive a regulated income for providing transmission services.
- However, in the case of the Transitional regime, where the assets were already constructed, the OFTO would only be responsible for financing the operation and maintenance of the assets, post construction.
- Transitional tenders were applied to projects that qualified for the offshore tender process by 31 March 2012 and only where the transmission assets had been or were being constructed by the offshore developer, then transferred to an OFTO.
- The Transitional regime and how it has been applied to the first round of operational projects tendered under the OFTO regime (TR1) is the focus of the benefits evaluation study.

Competitive asset-based licensing regime

Unlike some of the options considered by the Government and Ofgem, the Transitional OFTO regime is an "asset specific" based licensing approach

- Ofgem – following a competitive tender process to identify a preferred bidder – granted licences to own and operate specific offshore transmission assets rather than for a whole offshore zone or geographic area (which is the approach, for example, adopted for onshore electricity transmission).
- The OFTO operates specific, generation-related, transmission assets and takes on the responsibility for the operation and maintenance of those specifically defined transmission assets and their associated commercial risks.
- Unlike onshore electricity Transmission Owners (TOs), OFTOs for TR1 projects do not manage an integrated electricity transmission system but a dedicated radial connection - one of the key differences between the existing offshore and onshore networks in GB.
- The key building blocks of the regulatory revenue framework which then applies to OFTOs under the Transitional regime are as follows:
  - The OFTO is entitled to a stable, 20 year, Retail Price Index (RPI) inflation-linked revenue stream (the Tender Revenue Stream (TRS)) in return for operating, maintaining and the decommissioning the transmission assets.
  - The TRS is constant in real terms over the 20-year life of the OFTO licence – whilst the licence contains a price control, there are no price reviews as the TRS is fixed (in real terms) for 20-years at the tender process.
  - OFTOs are incentivised to perform as efficiently and effectively as possible primarily through an availability incentive which means that OFTOs receive an availability-based revenue stream.

Cost allocation and payment flows

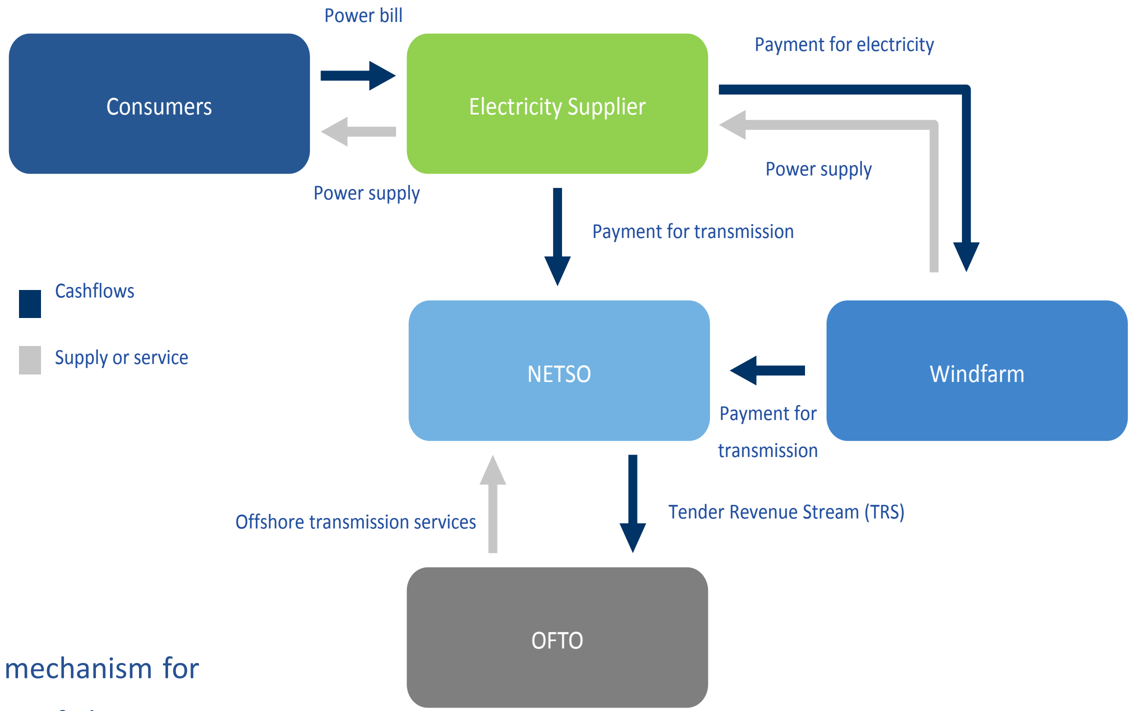
Transmission charging arrangements impact on cost and risk allocation

Importantly the TRS is paid to the OFTO by the GB NETSO (National Grid Electricity Transmission (NGET)) which then recovers these revenues as of its Transmission Network Use of System Charges (TNUoS) from generators and suppliers according to the principles of the TNUoS charging methodology – see Figure 1.

The consequence of the above is that the OFTO does not rely on the offshore generator for any of its revenue, thus reducing payment risk. Although the GB NETSO relies on the offshore generator to fund a proportion of an OFTOs allowed revenues[1], it is underwritten by the consumer should the offshore generator fail to pay its share.

The adopted TNUoS charging approach, as the cost recovery mechanism for OFTO revenues, as a consequence, impacts on the allocation of the costs associated with the transmission projects tendered as part of TR1, as well as the allocation of certain risks between industry parties.

Figure 1: Payment and service arrangements for offshore transmission



Note 1: Through what are termed "local" TNUoS charges.

Tender Round 1 outcomes

Favourable outcomes were achieved from the TR1 process … there was strong investor appetite with finance attracted in a difficult period for financial markets

- Investors and financial analysts that have reviewed the Transitional OFTO regime and its specific application to TR1 have commented that it exhibits a relatively favourable business and credit risk profile.
- The positive features of the regime which have typically been highlighted include:
  - the long term inflation linked revenue stream of the OFTO;
  - no exposure to the offshore generating asset;
  - OFTOs receiving their revenue from a solid counterparty (National Grid) and constrained operational risks.
- This was reflected in the favourable outcomes achieved in practice from the TR1 process. The competitive tenders saw a strong market response during a period of significant financial market volatility and uncertainty (the “credit crunch”). This included a large quantity of project finance attracted at reasonably keen rates.
- The contestable process also helped introduce new providers of transmission services to the industry and tapped into a wider pool of international capital, partly by allowing a diversification of risk across the GB transmission sector, rather than concentrating it on the few existing operators.

Evaluation framework

The development of relevant counterfactuals to the TR1 regime was central to our approach to this evaluation

We have undertaken an ex-post cost benefit analysis of the outcomes achieved from applying the Transitional OFTO regime to TR1 projects.

Central to our approach, and consistent with HM Treasury Greenbook Guidance, is the development of counterfactuals to TR1 and a comparison of these to the outcomes observed under the Transitional OFTO regime. We consider the cost savings achieved by the regime and the distributional question of who benefitted from the savings.

A central part of our evaluation framework has, therefore, been determining and quantifying counterfactuals to the Transitional OFTO regime. In this context, the counterfactuals are what we consider to be internally coherent scenarios of what alternative policy options might have reasonably been expected to be implemented in the absence of the adopted policy.

The objective of our analysis has not been to identify what would be the most likely counterfactual to the policy that was actually implemented, but rather to seek to identify a broad range of possible counterfactuals that help identify the potential quantum, range and sources of costs and benefits, and how those costs and benefits may have been distributed between industry parties.

Determining the counterfactuals

Our counterfactuals start from two central alternatives to the OFTO regime:

- licensed merchant generation solutions; and
- alternative licensed price control based approaches.

We believe these two scenarios together cover a wide range of realistic alternative counterfactuals, including the policy options originally considered by the Government and Ofgem at the time of the OFTO regime's development.

We develop two counterfactuals for the merchant generation solution, one involving the generator owning the assets, the other involving a sale and lease back arrangement.

We develop three counterfactuals under a price control based approach, two of which involve a scenario of extending existing TO licences to include offshore transmission and one involving a "zonal" offshore licensing approach to offshore transmission.

Quantifying the counterfactuals

Quantification of the outcomes under each of the developed counterfactuals needs to take into account what would have been most likely observed at the time, together with what had happened to date and what might happen in the future. Based on these principles, the assumptions used as our starting point for quantifying each of the counterfactuals are summarised in Table 1 overleaf.

Quantifying the counterfactuals

Table 1: Counterfactual descriptions and assumptions

Element	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4	Counterfactual 5
Summary	A licensed merchant approach for the TR1 transmission assets	A variant of the licensed merchant counterfactual	Onshore TO ownership of TR1 assets under price controls	A variant of onshore TO ownership of TR1 assets under price controls	Offshore zonal TO licence for offshore transmission delivery
Description	The generator is responsible for design, build, ownership and operation of the TR1 assets with financing arrangements an entirely commercial relationship internal to the wind farm project	The generation developer designs and constructs the assets, but a sale and leaseback arrangement is introduced for the ownership and the operation of the transmission assets	Onshore TOs have their exclusive onshore transmission licences extended offshore, and offshore services are included within existing onshore price control arrangements	Onshore TOs have their exclusive onshore transmission licences extended offshore, but a dedicated offshore price control is applied to the offshore assets and offshore services	Exclusive multi-zone offshore transmission licences where the TO is licensed (potentially through a competitive tender) for an entire offshore geographical zone and is then obligated to develop any future connections [1]
Counterfactual regimes					
Price controls?	No	No	Yes	Yes	Yes
Price reviews?	No	Potentially	Yes	Yes	Yes
Cost recovery	Through wind farm	Via lease back contract	TNUoS charges	TNUoS charges	TNUoS charges
Form of regulation	Not applicable	Not applicable	Ex-ante	Ex-ante	Ex-ante
Form of regime	Part of wind farm	Lease back terms	Revenue cap	Revenue cap	Revenue cap
Contestability	Potentially	Yes	No	No	Potentially

Note 1: the TR1 assets are adopted as operational by a licensee

Quantifying the counterfactuals

The quantified costs of the merchant counterfactuals have been determined through the following key assumptions:

- Operating costs which are broadly consistent with preferred bidders operating costs as revealed through TR1. We would have expected the transmission service provider (e.g. in Counterfactual 2) to have taken advantage of generator provided O&M packages, and the generation developer to have developed and procured a relatively low operating cost package.
- Cost of capital consistent with UK offshore wind generation operating under the Renewables Obligation (Counterfactual 1) and a cost of capital which reflects higher payment risks and exposure to the performance of the offshore wind farm when compared to the OFTO regime and regulated price controlled counterfactuals.

Similarly, the costs of the regulated price controlled counterfactuals have been determined through the following key assumptions:

- The allowed cost of capital used to determine allowed revenues. This is based on what Ofgem could reasonably have expected to have achieved at the time and subsequently over the life of the assets.
- Operating costs of existing transmission operators and other unsuccessful bidders (compared to OFTO preferred bidders) as revealed through the TR1 bids/ price reviews driving down costs over the licence term. There may be reasons why such amounts were bid[1], but it is difficult to suggest alternative assumptions as revealed prices reflect the specific context of TR1 projects.

There is of course uncertainty of what the costs would have been for each counterfactual and for this reason we have developed ranges for both the counterfactual financing and operating cost assumptions.

Note 1: For example, individual operators may have made particular operational and maintenance decisions as part of decisions on the more general commercial structure of their bids, including to address any perceived legal restrictions on particular operating solutions.

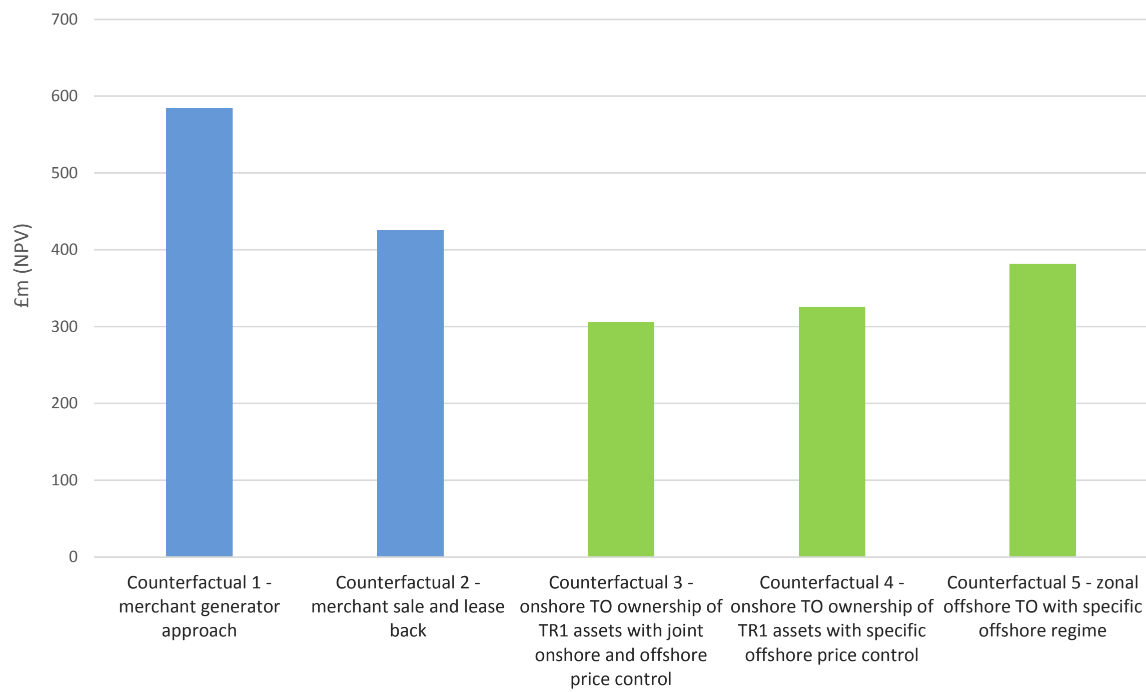
Measuring the cost savings

As the first step in the cost benefit analysis, we have quantified the cost savings from the TR1 projects having been delivered under the contestable Transitional OFTO regime as compared to if they had been delivered under the counterfactuals and the assumptions used to quantify the counterfactuals. We have then sought to identify the source of the cost savings (for example, from financing cost or operating cost savings) and subjected the results of the cost benefit analysis to sensitivity assessment.

What are the key findings?

- Based on our central counterfactual assumptions, the avoided costs (including tax savings) derived from the TR1 process compared to a range of merchant and regulated counterfactuals, are all greater in Net Present Value (NPV) terms than the £300m originally estimated by Ofgem.
- This is our assessment of the cost savings that were achieved from the contestable OFTO process in TR1.

Figure 2: Cost savings of the OFTO regime compared to counterfactuals (£m NPV)



What is the source of the cost savings?

The source of the savings differ depending on which counterfactual is chosen

- The Transitional OFTO regime exhibits cost benefits over all the counterfactuals. We have sought to identify the sources of the cost savings through comparing the component financing costs, operating costs, tax and bid costs for each counterfactual, to the outcomes under the competitive process for TR1. As Table 2 shows, the source of the cost savings differ depending on which counterfactual to the Transitional OFTO regime is chosen.

Table 2: Estimated net benefits of the OFTO regime compared to counterfactuals (£m NPV)

Benefit driver	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4	Counterfactual 5
	"licensed merchant generator approach"	"merchant sale and lease back arrangement"	"onshore TO led with the rollout of TPCR4 regime"	"onshore TO led with specific offshore regime"	"zonal offshore TO with specific offshore regime"
Estimated direct benefits (£m NPV) - cost savings under the OFTO regime relative to the counterfactual					
1 Financing costs	380	266	8	17	84
2 Operating costs	49	49	232	232	172
3 Tax	191	146	112	112	126
4 Bid costs	-35	-35	-35	-35	-
TOTAL BENEFIT (INC TAX)	585	426	306	326	381
TOTAL BENEFIT (EXC TAX)	**394**	**279**	**205**	**214**	**256**

Note: analysis is in NPV terms.

Interpreting the results

Compared to the merchant counterfactuals, we estimate the OFTO regime delivered financing cost savings as a result of reducing payment (counterparty), demand and other asset stranding related risks

In the case of the merchant generation counterfactuals, Table 2 shows that the cost benefits are driven by *lower financing costs*. This arises, in our view, from an optimal risk allocation, specifically as regards:

- lower payment (counterparty) risks under the OFTO approach, as a result of NGET (and ultimately consumers) guaranteeing payments;
- no exposure of the appointed OFTO to the performance of the associated offshore wind farm; and
- the degree of consumer underpinning of regulated investment which exists, as compared to the merchant counterfactuals.

The OFTO regime involves an allocation of relatively low probability but high impact stranding risks to consumers compared to the merchant counterfactuals, as well as allowing a combination of contestability for, with regulatory treatment of, transmission assets which form an integral part of offshore generation projects.

In short, this appears to amount to a relatively optimal approach and allocation of risk from a pricing perspective given the nature of the contestable opportunity created.

Interpreting the results

Compared to the regulated price control counterfactuals, we estimate the OFTO regime delivered lower operating costs

In the case of the regulated price controlled counterfactuals, Table 2 shows that the savings arise from lower operating costs associated with the likely path of these costs over time. The scale of the saving depends upon the view as to:

- the speed at which the process of price control reviews would have moved the projects to the efficiency frontier; and
- whether price reviews would have overcome challenges of regulatory asymmetry of information by setting prices through a price review negotiation, rather than contestable process of revealed pricing.

We believe that the key attributes of the implemented OFTO approach in TR1, including the contestable nature of the OFTO regime and the clear risk profile for TR1's post construction assets, are also the source of the cost savings which we estimate when comparing to the regulated price controlled counterfactuals:

- The OFTO approach helped define the true risk profile of the TR1 assets. In contrast, for Counterfactual 3, we believe it would have been more difficult to isolate the risk profile of the OFTO from the rest of the transmission 'project portfolio' resulting in higher allowed financing costs.
- If compared to a scenario where a relatively low cost of capital is assumed in the counterfactual, the low risk profile of the OFTO regime and the contestable opportunity created, still appears to have allowed financing costs under the OFTO approach roughly equivalent to that allowed for low risk RAB-based financing.[1]

Note 1: Financing costs are lower in Counterfactual 3 compared to Counterfactual 4 as a result of the relative regulatory treatment of allowed debt costs in each counterfactual. The allowed cost of equity for Counterfactual 4 is lower than for Counterfactual 3 but Counterfactual 3 is based on projected changes in an indexed allowed cost of debt, whilst Counterfactual 4 is based on an embedded cost of debt allowance set to reflect financing costs at the time within a specific offshore price control.

What can be drawn from the analysis?

Revealed prices through a contestable process are useful in understanding true costs

We believe the analysis shows that revealed prices through a contestable process are useful in understanding true costs. This was possible because the 'market offer' reflected a clear set of risks that allowed efficient, competitive pricing. It is difficult to see how this clarity and similar outcomes could have been realised through a more price regulated based regime in the context of these specific offshore assets.

Whilst there may be other instances where such a set of circumstances would allow this – that is, where there are other highly marketable transmission assets of sufficient scale and appropriate scope – there are limits as the extent to which lessons can be drawn for the onshore electricity transmission network. **The results are context-specific to TR1 and the contestable opportunity that was created reflecting the underlying technical and other characteristics of the assets in question.**

Post construction OFTO assets for TR1 are point-to-point generation connection wires outsourced to third party providers. These features, coupled with the regulatory framework applied, has created a relatively low risk profile for OFTO investors. In turn, this approach has created highly contestable bidding opportunities, attracting significant operator and investor interest.

However, in reading across to what might be implied for the onshore regime, it is important to recognise that TR1 OFTOs are of a materially different scale and risk profile to a full electricity transmission network.

Distribution of cost savings

Who benefits from the cost savings?

TR1 has produced overall cost benefits arising from different sources: financing costs when compared to merchant counterfactuals and from operating costs in terms of price controlled counterfactuals. But who are the ultimate beneficiaries of these cost savings, in terms of different groups and specifically final consumers?

It may on first appearance seem that who benefits is a relatively straightforward question to answer: the offshore wind farm uses the offshore transmission assets, consumers benefit from the generation they produce and consumers (eventually) pay the full costs of offshore transmission. Therefore, any costs savings derived from a particular approach to the delivery of offshore transmission should ultimately benefit consumers.

In practice, however, the question is much more complicated due to the charging arrangements for offshore transmission and the market and subsidy support arrangements for offshore wind. **As all of these aspects are interlinked, it is important to ensure that the counterfactuals reflect this.**

Distribution of cost savings

In comparisons with regulated price control counterfactuals … both offshore generators and consumers will have benefited from the cost savings resulting from the contestable OFTO approach

- For the regulated price control counterfactuals, we think it is likely the cost allocation approach applied and therefore the flow of any benefits would have been consistent with the OFTO regime – that is, under the latter, a proportionate share of the socialised cost savings would be likely to flow to consumers, although because of the structure of the transmission charging regime, generators will have received c. 70-80 per cent of the benefits through a reduction in their TNUoS charges.
- As a result, under this scenario both offshore generators and consumers will have benefited from the savings derived by the contestable OFTO approach that was adopted for TR1.
- For clarity, this means that GB consumers will have benefited directly from the estimated reduction in the socialised share of the offshore transmission cost base associated with the TR1 projects, with offshore generators also receiving lower TNUoS charges benefitting investors in those specific projects.

Distribution of cost savings

For comparisons with merchant counterfactuals … understanding the distribution of benefits is more complicated and depends on what is assumed regarding offshore wind subsidy levels

- The comparisons with merchant counterfactuals are more challenging as the treatment of transmission costs is different; and assessing the flow of benefits depends upon what is assumed regarding the level of administered subsidy that accounts for transmission costs in the overall offshore generation support regime.
- Under the merchant counterfactuals, offshore generators would have directly paid for the full costs of the offshore transmission connection, rather than sharing the costs with customers as in the case of the cost recovery mechanism with the price control counterfactuals.
- The key question is whether or not the support regime in the merchant counterfactuals would have compensated them for these additional costs, as the position of the consumer also needs to take into account the level of subsidy provided to the offshore generators, if the two types of regimes are to be compared.

Distribution of cost savings

In comparisons to merchant counterfactuals … there will have been savings for consumers if a higher level of subsidy support had needed to be provided to cover a higher allocation of offshore transmission costs under the merchant counterfactuals

- If the merchant counterfactuals were to involve the same subsidy contribution to transmission costs through the same level of ROC support as now, then consumers would not have benefited from the OFTO regime as all cost savings would have flowed to generators.
- However, if subsidy levels would have had to be higher in the merchant counterfactuals to reimburse generators for the higher proportion of offshore transmission costs allocated to them under the merchant approaches (and thereby holding generator returns constant between the merchant counterfactuals and the OFTO regime), consumers would be better off in the OFTO regime because of the lower level of overall subsidy required in the OFTO regime as opposed to the merchant regime (even though the cost savings on OFTOs would flow in entirety to the generators). Clearly the extent of any benefits in this trade-off would depend upon the level of ROC support allowed for offshore wind.
- In return for this reduced subsidy, however, additional (e.g. stranding related) risks have accrued to consumers under the applied OFTO regime, which must be balanced against the savings in subsidies that may have been achieved due to the OFTO regime, reflecting the trade-offs often faced in creating new contestable investment opportunities.

However, at a minimum, cost savings achieved by the OFTO regime can be considered to apply downward pressure on the subsidy levels needed in future to achieve offshore wind hurdle rates.

Implications for price discovery

Competition involving revealed pricing can be employed where it is possible to structure such approaches …

- Whilst it is important to realise that the OFTO regime cannot be replicated everywhere, a lesson to be drawn is that where such opportunities do exist and any trade-offs are acceptable, such approaches should be actively considered.
- It is arguable that the contestable TR1 process has moved the industry closer to the efficiency frontier quicker than may have been possible under alternative policies and potentially this should be reflected in the future assumptions that are made for offshore wind subsidy costs in the UK.

… with price discovery from TR1 likely to help apply long term downward pressure on offshore wind industry costs and subsidy levels.

- Where subsidy prices are administered and set to reflect costs at an industry rather than individual project level, the effect of reducing offshore transmission costs, if reflected in subsidy prices, could potentially be amplified in future as Crown Estate Round 3 wind farm project costs, for example, are reduced for the marginal project.
- The Electricity Market Reform (EMR) delivery plan, for example, applies a Contract for Difference (CfD)[1] strike price of £155/MWh for qualifying offshore wind projects up to 2015/16 falling to £140/MWh by 2018/19 and may already reflect reduced offshore wind industry costs at the margin, as a result of the OFTO regime.

Note 1: CfD Feed-in-Tariffs (FiTs) are part of a number of proposed reforms to renewable electricity support arrangements in the UK for offshore wind and other low carbon generation technologies.

Conclusions

The OFTO approach adopted has resulted in significant cost savings when compared to plausible counterfactuals

- The OFTO approach adopted has resulted in significant cost savings when compared to plausible merchant and price control counterfactuals that might have been applied in the absence of the chosen approach; in the case of the former these arise from financing cost savings and in the case of the latter, operational costs.
- In turn, these reflect the optimality of payment risk allocation viz-a-viz the merchant regime and the benefits of contestability in terms of revealing pricing when compared to the price control counterfactuals (although caution is warranted in terms of any comparisons with the wider onshore electricity transmission regime).
- Understanding the distribution of benefits is much more complex. Whilst consumers are in a better position due to overall lower transmission costs as compared to the price control counterfactuals, which would appear to be allocated in the same way under both regimes, the outcome versus the merchant counterfactuals depends upon what is assumed regarding the level of support – paid for by customers – provided to offshore generators versus that in the OFTO regime.
- If a higher level of support were to have been provided to cover a higher allocation of offshore transmission costs under the merchant counterfactuals, the consumer would be likely in a better cost position in the OFTO regime due to the lower level of total renewable support costs, albeit in return for taking on certain, relatively remote, stranding risks.

Contents

1 INTRODUCTION

The purpose of the report is to provide an economic evaluation of the Transitional Offshore Transmission Owner (OFTO) regime as applied to Tender Round One projects

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- Unlike in other jurisdictions, this involves a competitive tender process to appoint new offshore electricity network operators who have the responsibility for operating newly constructed electricity transmission network assets, which connect offshore electricity generation (wind farms) to the shore.
- A consortium of CEPA and BDO[1] was engaged by Ofgem to assess the benefits that may have been achieved from the introduction of this competitive OFTO regulatory framework as applied to the first round of projects tendered under the regime - Tender Round One (TR1).
- This report sets out the methodology that we have developed and used to assess these benefits, our findings on the estimated cost savings that have been realised from applying the OFTO regime to the TR1 projects and how those savings may have been distributed between different parties (that is, consumers and generators) through the funding arrangements for offshore wind and offshore transmission in GB.

In this introductory section we review the background and context to the regulation of offshore electricity transmission in GB. We also set out the focus of our work and the structure of the rest of the report.

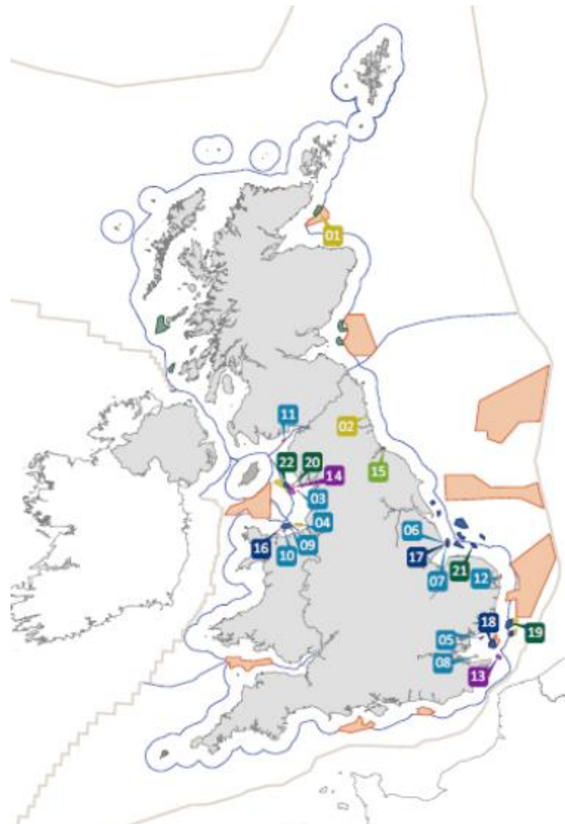
Note 1: The majority of the report analysis and its findings have been prepared by CEPA. BDO as part of a consortium have supported CEPA with a review of bids submitted in the TR1 process and the modelling undertaken.

Tender Round One included offshore transmission assets related to a number of early offshore wind farms in the UK

Including projects from the Crown Estate Round 1 and 2:

- The offshore wind farm sector in the UK has developed with a series of licensing 'Rounds' co-ordinated by the Crown Estate, the landlord and owner of the seabed.
- Round 1 was launched in 2000 and involved projects that were typically no more than 30 turbines in areas selected by developers close to the shore.
- In 2003, the much larger Round 2 was issued, located further offshore and in deeper waters. It was formed of three strategic areas; Greater Wash, Greater Thames and the Irish Sea.[1]
- There are 17 Round 2 projects with a total generating capacity of some 7.2 GW. As of August 2012, five Round 2 projects were fully operational with a capacity of 1.2 GW and four were under construction with a design capacity of some 1.8 GW.

Figure 1.1: Offshore wind farms in construction or operation



No	Project name	Equity investors	Capacity (MW)
Operational demo sites			
01	Beatrice Demo	SSE	10
02	Blyth	E.On	4
Round 1 operating assets			
03	Barrow	Centrica, Dong	90
04	Burbo Bank	Dong	90
05	Gunfleet Sands I & II	Dong, Marubeni	173
06	Inner Dowsing	Centrica, TCW	97
07	Lynn	Centrica, TCW	97
08	Kentish Flats	Vattenfall	90
09	North Hoyle	RWE, JP Morgan IIF, Prudential M&G	60
10	Rhyl Flats	RWE	90
11	Robin Rigg (E&W)	E.On	180
12	Scroby Sands	E.On	60
Round 2 operating assets			
13	Thanet	Vattenfall	300
14	Walney 1	Dong, SSE, PGGM & Dutch Ampere	184
Round 1 assets under construction			
15	Teesside	EDF	62
Round 2 assets under construction			
16	Gwynt y Môr	RWE, Siemens, Stadtwerke Munchen	576
17	Lincs	Centrica, Dong, Siemens	270
18	London Array 1	Dong, E.On, Masdar	630
Round 2 partially operational sites			
19	Greater Gabbard	RWE, SSE	504
20	Ormonde	Vattenfall	150
21	Sherringham Shoal	Statkraft, Statoil	317
22	Walney 2	Dong, SSE, PGGM & Dutch Ampere	184
Round 1 and 2 extension sites			
Round 3 zones			

Source: Redpoint energy and GL Garrad Hassan sourced from TCE, UK Offshore Wind report 2012

Note 1: Also referred to as Liverpool Bay.

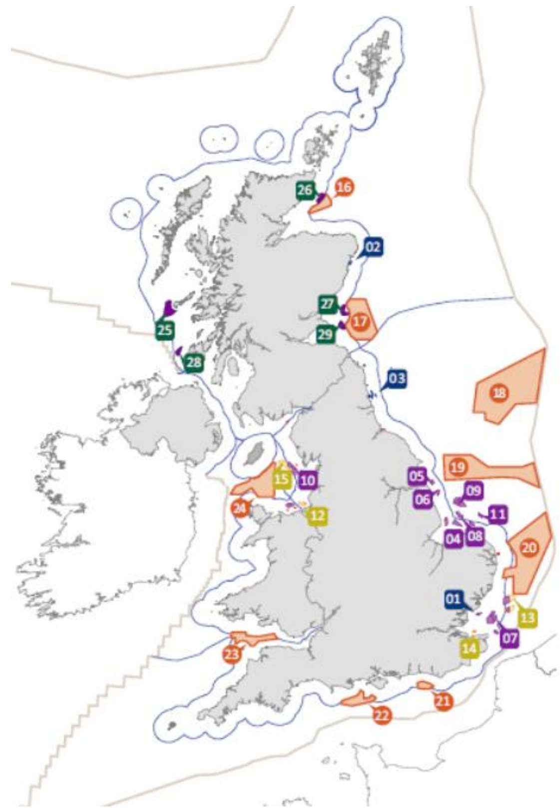
Introduction

There is longer term development potential in the UK offshore wind sector which will also require future offshore transmission network development

Including Crown Estate Round 3 and beyond:

- While the Round 2 projects are large in comparison to Round 1, the size of offshore wind projects and potential capacity deployment under Round 3 is expected to be even greater; over 32GW is in the development pipeline.
- Figure 2 (right) illustrates the progression of Round 1, 2 and 3 projects from development and construction through to operation.
- With the expected contribution of Round 3 projects, the UK now has more operational and pipeline offshore wind capacity than any other European country (with more operational offshore wind capacity than all other European countries combined).[2]
- All of these projects will require new offshore transmission assets to transmit the electricity to shore and into the National Grid.

Figure 1.2: Offshore wind farms in operation, construction and development



Demo sites			
01	Gunfleet Sands 3	Dong	12
02	Aberdeen Bay European Offshore Wind Deployment Centre	Vattenfall Wind Power UK, and Aberdeen Renewable Energy Group (AREG)	Up to 100MW
03	Blyth offshore wind demons-tration site	New and Renewable Energy Centre (NAREC)	Up to 100MW
Round 2 sites			
04	Docking Shoal	Centrica	540
05	Westermost Rough	Dong	240
06	Humber Gateway	E.On	219
07	London Array 2	Dong, E.On	370
08	Race Bank	Centrica	620
09	Triton Knoll	RWE	900-1200
10	West of Duddon Sands	Iberdrola, Dong	389
11	Dudgeon	Warwick	560
Round 1 and 2 extension sites			
12	Burbo Bank Extension	Dong	234
13	Galloper Extension	SSE, RWE	504
14	Kentish Flats 2 Extension	Vattenfall	51
15	Walney Extension	Dong	750
Round 3 zones			
16	Moray Firth	EDP Renovaveis, Repsol	1300-1500
17	Firth of Forth	SSE, Fluor	3465
18	Dogger Bank	RWE, SSE, Statkraft, Statoil	9000-12800
19	Hornsea	Mainstream, Siemens, Dong	4000
20	East Anglia	Iberdrola, Vattenfall	7200
21	Rampion	E.On	665
22	Navitus Bay	Eneco, EDF	900-1200
23	Atlantic Array	RWE	1500
24	Irish Sea	Centrica, Dong	4185
Scottish territorial waters sites			
25	Argyll Array	Iberdrola	1800
26	Beatrice	SSE, Repsol	1000
27	Inch Cape	EDP Renovaveis, Repsol	905
28	Islay	SSE	690
29	Neart na	Mainstream	450

Source: Redpoint energy and GL Garrad Hassan sourced from TCE, UK Offshore Wind report 2012

Note 2: EWEA (2012): 'The European offshore wind in industry key 2011 trends and statistics'

The deployment of offshore wind is likely to play an important role in meeting UK renewables targets

- The Round 2 projects were originally developed within the context of the Government's 2003 Energy White Paper target of increasing the amount of electricity supplied from renewable sources to 10 per cent by 2010, with an aspiration to achieve 20 per cent by 2020.
- UK Government policy context has subsequently evolved, particularly in response to the 2009/28/EC European Union (EU) Directive on renewable energy. **The UK Government has now agreed a target of meeting 15 per cent of the UK's energy consumption from renewable sources by 2020.**
- The Department of Energy and Climate Change (DECC)'s Renewables Roadmap shows that in order for this renewable energy target to be met, around 30 per cent of UK electricity will be required to come from renewables by 2020.
- Offshore wind, as one of the renewable technologies considered to have greatest deployment potential in the UK, is likely to play an important role in meeting this target.

Supporting investment into the offshore wind sector has become a key component of the Government's energy policy. The cost effective and timely delivery of offshore wind is likely to play an important role in 2020 renewables targets and beyond.

DECC's energy road map has emphasised that a substantial reduction in offshore wind costs will be required to support the effective deployment of the sector's potential

"We are determined to drive down costs and are establishing an industry Task Force to set out a path and action plan to reduce the costs of offshore wind, from development, construction and operations to £100/MWh by 2020."

DECC (2011): 'UK Renewable Energy Roadmap'

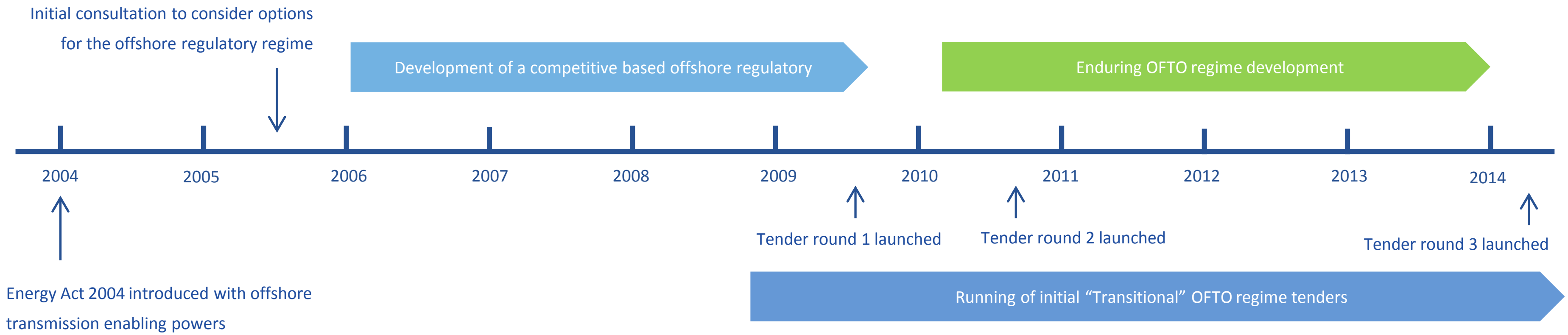
- These objectives have been reflected in recent Government consultations to develop an offshore wind sector strategy, the Crown Estate's Offshore Wind Cost Reduction Pathways Study and proposed changes to the support framework for offshore wind with the introduction of Contract for Differences (CfDs) to replace the Renewables Obligation (RO).
- Ofgem and DECC have also been exploring opportunities for network savings through the Offshore Coordination Project.

While the Crown Estate's pathways study has, for example, identified many diverse ways in which offshore wind sector costs can be driven down, reductions in offshore transmission network connection costs have the ability to make an important contribution towards the vision of reducing the costs of offshore wind as the pipeline of deployment takes place.

The offshore transmission regulatory framework has been developed to support effective deployment of offshore wind potential

- At the time the Crown Estate's Round 2 projects were under development, and now looking forward to projects under Round 3, it is recognised that to deliver increased deployment of offshore wind capacity, the UK will need significant and timely investment in the grid, both to bring electricity ashore and to strengthen the onshore transmission network:
- A clear and predictable regulatory framework for offshore transmission is considered an important component of supporting growth in the critical mass of the offshore wind generation market which as the Crown Estate's pathways study shows is so important, together with timely delivery of projects, to future achievement of Government targets.
- To facilitate this investment, the UK Government working with Ofgem, has over a number of years developed and implemented a system of regulation for offshore transmission which is organised around a competitive tendering approach for granting offshore transmission licences with supporting price control arrangements.

Figure 1.3: Timeline of OFTO regime's development



Focus of our study

The assessment of Tender Round One costs and benefits:

- The focus of our study is whether the implemented OFTO regime, has led to timely and cost effective delivery of offshore transmission services (along with other economic benefits) compared to alternative approaches which could have been applied to early offshore transmission – specifically the projects tendered under TR1.
- We have sought to assess the direct and indirect benefits that have arisen from the TR1 process by comparing the outcomes observed under the Transitional OFTO regime to counterfactual states of the world. To do this we draw on the experience of regulatory frameworks applied elsewhere in the energy sector and other industries.
- We note that TR1 took place at a specific time and within a specific context. That time and context is crucial to the cost benefit analysis, and whilst inferences can be made for future tendering rounds, the findings primarily reflect the characteristics and context of the transmission projects which were included in TR1.

Some of these impacts have been quantified. Others have been considered more from a qualitative perspective.

Report structure

The rest of this report is structured as follows:

- **Section 2:** we review the background and context to the Transitional OFTO regime's development based on a review of published Government and Ofgem policy documents. We also review the Transitional OFTO regime's design principles and the TR1 process.
- **Section 3:** we set out our approach to the benefits assessment, including our cost benefit analysis framework and modelling methodology.
- **Section 4:** we present the outcomes of the TR1 process, in terms of the sources of finance which were accessed in TR1, financing costs, operational outcomes and the tender process itself.
- **Section 5:** we develop counterfactuals to the transitional OFTO regime and how they compare to the OFTO regime in terms of regime design and risk profile.
- **Section 6:** we present our findings of the cost savings that may have been realised from applying the transitional OFTO regime as compared to our counterfactuals.
- **Section 7:** considers the issue of who may have benefited from any cost savings that may have been realised from the contestable approach which was adopted for TR1 and the potential long term benefits from this process.
- **Section 8:** provides conclusions.

The main report is supported by a series of annexes which provide supporting analysis and details of certain assumptions used to develop the cost benefit analysis.

2

THE TRANSITIONAL OFTO REGIME

Introduction

In this section we review:

- The Transitional OFTO regime's development and the alternatives which were considered by both the UK Government and Ofgem at the time.
- The key features and principles of the adopted regulatory framework, including the licensing appointment process through a competitive tender and how risks have been allocated and managed within these arrangements.

We show that:

One – The Government and Ofgem considered various options for the offshore transmission regulatory framework, including licensed "merchant" and price control based approaches.

Two – For the early regime projects, the developers of the wind farms have been responsible for building the offshore transmission connections themselves.

Three – Prospective OFTOs are then required to bid an annual revenue stream in return for purchasing the assets from the generator and operating and maintaining them for 20-years.

Four – The regime has facilitated third party involvement in the financing and O&M of offshore transmission assets and has brought competitive pressure to bear on these activities.

The Transitional OFTO regime

Various options for offshore transmission regulation were considered by the Government, including "merchant" led and exclusive price control based approaches

- The competition based OFTO licensing regime emerged from a set of options for an offshore transmission regulatory regime that included a licensed price control based method or a licensed "merchant" approach (similar to how a number of gas and electricity interconnectors have been regulated in GB and Europe).
- Following an industry consultation process, the Government decided that a licensed price control approach was the optimal solution.
- Both exclusive (a licensing system based on onshore network regulation) and non-exclusive (involving GEMA issuing licences for offshore transmission zones or projects following a competitive tender) approaches were considered by Ofgem and the Government.
- It was concluded that a non-exclusive "common tender" approach was the most appropriate model for licensing offshore transmission in GB.

See Annex A for a more detailed review of the regime's development and the options considered.

Figure 2.1: Original options considered for offshore regulatory regime

	Not considered practical	*Considered practical*		
Components	Option 1	Option 2	Option 3	Option 4
Overall regulatory regime design	Unlicensed or license exempt approach.	A price control regulated approach to offshore electricity transmission. Participation in offshore transmission would be a licensable activity.		A licensed merchant approach to offshore transmission.
Expected TO and SO role under regime	No details provided at the time as was not considered practicable or indeed even legally permissible because of the requirements of the Internal Market Electricity Directive (IMED).	Appointed offshore TO responsible for planning investment in networks. Option to extend NGC's remit as GBSO to encompass system operation offshore.		Licence could authorise developer to carry out SO and TO activities with respect offshore assets.
Approach to charging – who pays?		SO would recover TO costs via charging methods from electricity generators and suppliers.	As per Option 2 but with a degree of cost cross-subsidisation with other onshore users.	Offshore wind generators would meet all the costs upfront of developing the offshore link.
Key design principles	Effectively the "do nothing" option identified at the time.	Onshore and offshore consistency. Special licence conditions would establish price controls.	As per Option 2 but with greater cost socialisation to support offshore wind investment.	Light touch. Minimum regulatory arrangements consistent with IMED and Renewables Directive.

The Transitional OFTO regime

There is a Transitional OFTO regime with Transitional OFTO projects

During the regulatory framework's development, there was recognition that for a number of projects, the offshore generator developer had already started construction or was undertaking steps towards construction.

- The Government and Ofgem, therefore, developed a Transitional OFTO regime that would apply to those projects that had either awarded construction contracts or started construction works.
- As with the regime that was expected to apply on an enduring basis to all future offshore transmission projects (the "enduring regime"), this involved a tender process to award an OFTO with an offshore transmission licence that provided the right to receive a regulated income for providing transmission services.
- However, in the case of the Transitional regime, where the assets were already constructed, the OFTO would only be responsible for financing the operation and maintenance of the assets, post construction.
- Transitional tenders were applied to projects that qualified by 31 March 2012 into the tender process and only where the transmission assets have been or will be constructed by the offshore developer, then transferred to an OFTO.

The Transitional regime and how it has been applied to the first round of projects tendered under the OFTO regime (TR1) is the focus of our economic evaluation study. In the remainder of this section, we focus on the commercial and regulatory design principles that have underpinned the Transitional OFTO regime as applied in practice.

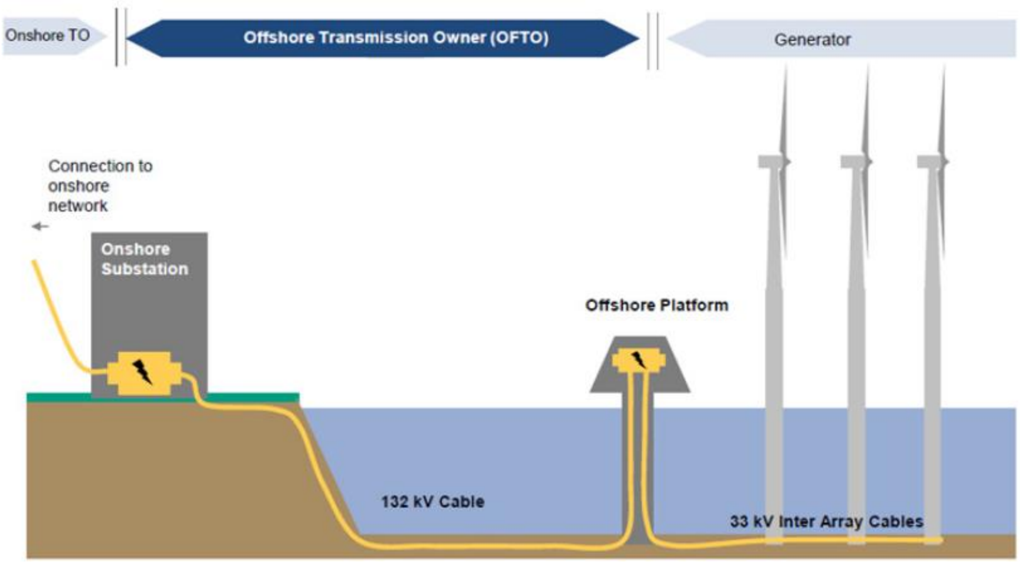
The Transitional OFTO regime

The Transitional OFTO regime is a competitive asset-based licensing approach

Where an OFTO takes ownership of a generation connection, once the transmission assets are constructed:

- In contrast to some of the alternative options were considered by the Government and Ofgem (see Annex A), the Transitional Regime that has been applied to the TR1 projects is an "asset" specific based licensing approach.
- Ofgem - following a competitive tender process to identify a preferred bidder – granted licences to own and operate specific transmission assets rather than for a whole offshore zone or area (which is the approach, for example, adopted onshore).

Figure 2.2: Illustrative offshore transmission assets



Under the Transitional regime:

i. The OFTO only takes on the responsibility for the operation and maintenance of specifically defined transmission assets.
ii. There is no enduring obligation to connect future offshore generators as for example applies to onshore networks.[1]
iii. The OFTO operates specific, generation related, assets and the commercial risks associated with those specific assets.
iv. Unlike onshore Transmission Owners (TOs), the OFTO is not managing an integrated electricity transmission system, but a dedicated radial generation connection.

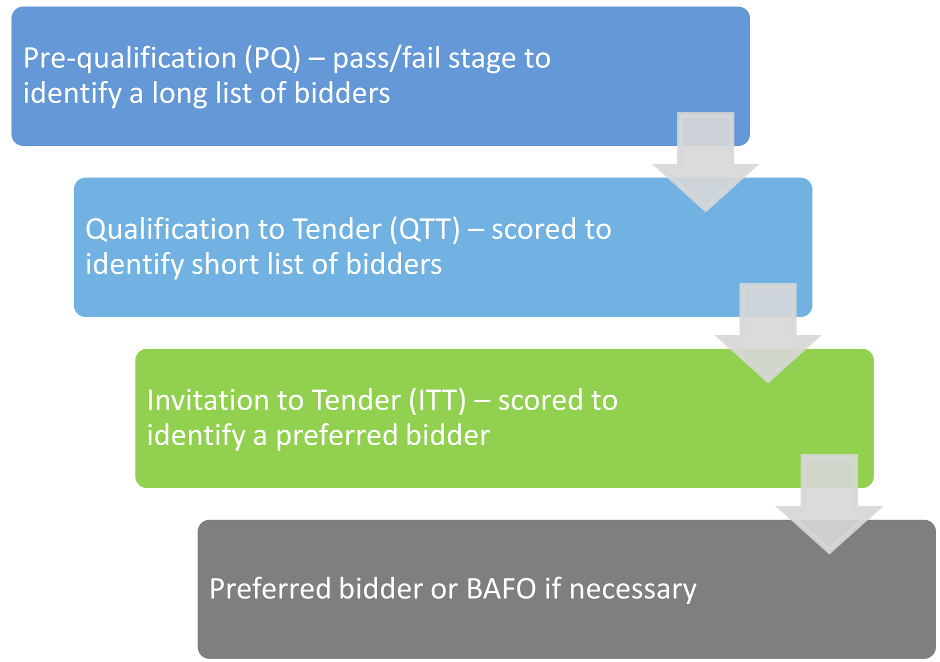
Note 1: The existing generator can request an increase in capacity, however, the OFTO has the right to refuse to undertake additional capex which exceeds 20% of the transfer value of the assets.

Ofgem was responsible for running the competitive tender process

The tender process for TR1 was run as follows:

- In the Transitional OFTO regime, the tender process for the transfer of the OFTO assets has been run alongside or post completion of the asset construction process. There have been a number of stages in this bidding process.
- For TR1, Ofgem ran an initial pre-qualification stage (to identify bidders experience and capabilities), followed by a Qualification to Tender (where bids are based on generic and project specific information memoranda) and an Invitation to Tender (ITT) stage.
- Following the ITT stage Ofgem was also able to trigger a Best and Final Offer (BAFO) where some or all short-listed bidders may be required to resubmit their tender proposals where it has not been possible to identify a preferred bidder at the ITT stage.
- Once a preferred bidder is appointed, there is period where any outstanding matters are addressed prior to Licence Grant / financial close.

Figure 2.3: Transitional regime tender process



The OFTO is entitled to a stable, 20 year, inflation-linked revenue stream

Licensing policy:

- OFTOs are regulated by Ofgem through licences like other regulated energy networks in the UK (i.e. there are both standard and amended standard licence conditions). Like onshore networks, OFTOs are subject to price controls.
- The OFTO is entitled to a stable, 20 year, Retail Price Index (RPI) inflation-linked revenue stream (the Tender Revenue Stream (TRS)) in return for operating, maintaining and the decommissioning the transmission assets.
- The TRS is constant in real terms over the 20-year life of the OFTO license – while the licence applies price controls, there are no price reviews as the TRS is fixed (in real terms) for 20-years at the tender process.

Building blocks of the TRS:

- The OFTO's 20-year TRS reflects the costs of acquiring, operating and maintaining the assets. This includes O&M costs, insurance costs, special purpose vehicle (SPV) management costs, decommissioning costs, taxes and financing costs related to the acquisition of the assets from the offshore generation developer.
- Costs such as O&M and financing are based on the successful bidders' bid, while the acquisition price reflects the assessment by Ofgem of the economic and efficient costs of developing and constructing the transmission assets incurred by the windfarm developer, the Final Transfer Value (FTV).
- The TRS that is enshrined in the OFTO's licence is adjusted before financial close, to reflect the FTV.

The Transitional OFTO regime

OFTO licences include performance incentives and uncertainty mechanisms

Appointed OFTOs are incentivised to perform as efficiently and effectively as possible through a range of performance incentive and uncertainty mechanisms. These include:

- An availability incentive, which imposes penalties if the OFTO is unable to achieve an availability target and bonus payments if the target is exceeded (the availability target has usually been set to 98% on OFTO projects to date).
- A competitive tender process, which requires prospective OFTO bidders to submit the most competitive TRS and service proposal they can achieve to give themselves the best chance of winning the licence.[1]

For costs that Ofgem has considered are beyond OFTOs' control, the Transitional OFTO regime licences also include a range of uncertainty mechanisms which adjust the TRS in particular circumstances. For example:

- The TRS is automatically adjusted for changes in a set of pre-specified costs such as licence fees, network rates, Crown Estate lease costs and legislative changes impacting on decommissioning costs.
- Specific unforeseen events impacting the OFTOs ability to deliver its obligations are protected against through an Income Adjusting Event clause in licences. This clause also protects companies against *force majeure*.
- An Exceptional Events Mechanism provides protection against penalties under the availability incentive mechanism for events that can be demonstrated as beyond the OFTO's reasonable control.

Note 1: See KPMG (2013): 'Offshore Transmission: An Investor Perspective

The Transitional OFTO regime

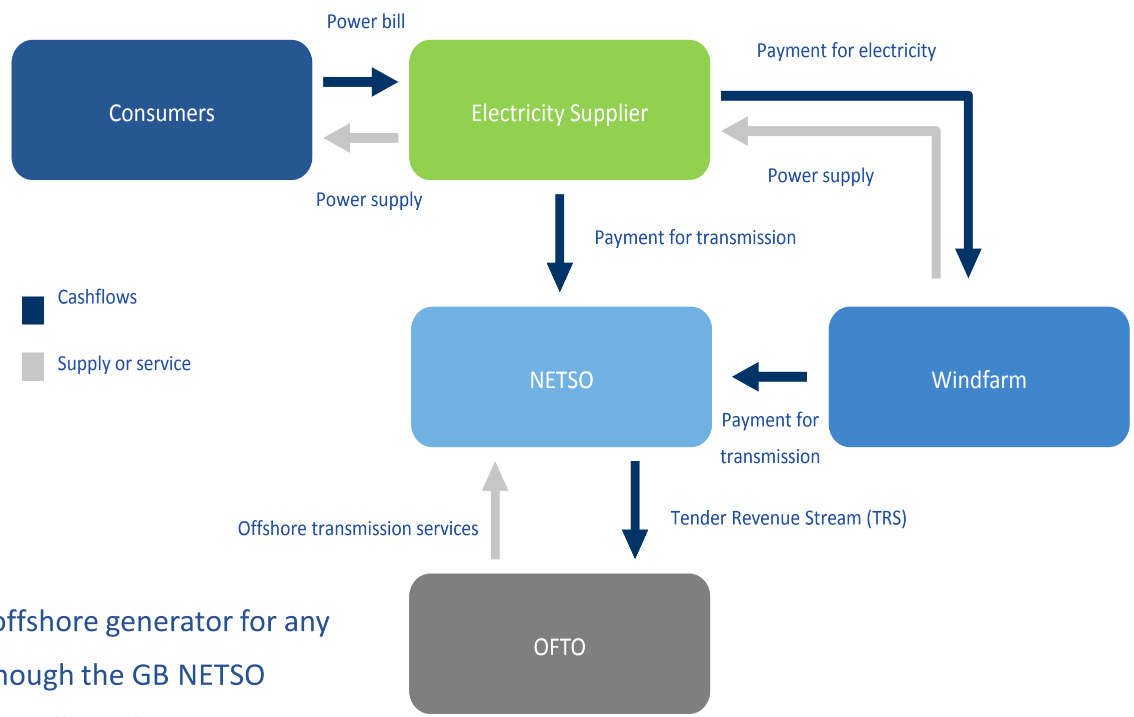
Contractual and payment arrangements

Under the Transitional OFTO Regime, a range of obligations have been imposed upon OFTOs by licences and a series of industry codes and standards and contractual agreements.

<u>Importantly</u> the TRS is paid to the OFTO by the NETSO (National Grid – an A credit rated company) which then recovers these revenues as of its Transmission Network Use of System Charges (TNUoS) from generators and suppliers according to the principles of the TNUoS charging methodology.

The consequence of this is that the OFTO does not rely on the offshore generator for any of its revenue, thus significantly reducing counterparty risk. Although the GB NETSO relies on the offshore generator to fund a proportion of an OFTOs allowed revenues, it is underwritten by the consumer should the offshore generator fail to pay its share.

<u>Figure 2.4: Payment and service arrangements for offshore transmission</u>



<u>Source: KPMG</u>

The adopted TNUoS charging approach, as the cost recovery mechanism for OFTO revenues, as a consequence, impacts on the allocation of the costs associated with the transmission projects tendered as part of TR1, as well as the allocation of certain risks between industry parties.

The Transitional OFTO regime

OFTOs are considered to exhibit a favourable business and credit profile

Investors and financial analysts that have reviewed the Transitional OFTO regime and its application to TR1 have commented that it exhibits a favourable business and credit risk profile.

"Operational Offshore Transmission Owners (OFTOs) in the UK exhibit a favourable credit risk profile … Subject to the terms of the financing structure, we could consider OFTO transactions to be comparable with regulated onshore electricity and gas transmission network businesses that are rated in the Baa1/A3 range … Our positive view of OFTOs' business risk profile reflects … A transparent and predictable regulatory regime … A predictable availability based revenue stream payment mechanism … The ability to pass through certain costs … Limited operating risks"

Source: Moody's (2013): Commentary on Operational UK Offshore Transmission Owners

The positive features of the regime that are highlighted by investors include: the long term inflation linked revenue stream of the OFTO; no exposure to the generating asset; OFTOs receive their revenue from a solid counterparty (the GB NETSO – a ring fenced investment grade rating business) and contained operational risks.

As well as onshore regulated gas and electricity networks, the tender process to appoint OFTOs and the availability based performance incentive, has also drawn comparisons with the UK Private Finance Initiative (PFI).

The Transitional OFTO regime

There are similarities but also differences between OFTOs and PFI

PFI was introduced in the 1990's order to engage the private sector in the design, build, finance and operation of publicly owned social and economic infrastructure. It has been used across a broad range of sectors. Over 700 projects have reached financial close, securing private sector investment of around £55bn.

> *"Over the last fifteen years, private finance has become the predominant method by which public authorities procure infrastructure in many sectors. It has been used particularly where there is the need for a significant capital outlay followed by ongoing services, for example for hospitals, schools and roads … Under a typical PFI deal, the public sector enters into a long-term contractual arrangement with private sector companies, which undertake to design, build, operate (and often maintain) an asset. There are around 700 PFI contracts in the United Kingdom … they are usually long-term arrangements typically spanning 25 to 30 years."* [1]

What are the similarities and differences between PFI and the Transitional OFTO regime?

Similarities

- √ Availability based revenue structure.
- √ Fixed contract period.
- √ Revenues set and fixed prior to operation.
- √ Competitive tender process.
- √ Revenues indexed to inflation (most generally).
- √ Deals with infrastructure asset with public benefits.
- √ Revenue payments include a cost of capital.

Differences

- × Tender process not run by ultimate counterparty.
- × Penalties under PFI not capped like the OFTO regime.
- × PFI may be only partially indexed, and to different indices e.g. RPIX, CPI, COPI.
- × Asset ownership reverts to public sector after contract period.
- × PFI is typically Design Build Finance and Operate. OFTO regime (at least at TR1) does not include design and construction risk.
- × Transitional OFTO Regime does not have a mechanism for sharing in refinancing gains.

Note 1: Source: NAO (2011): 'Lessons from PFI and other projects'

Conclusions

In this section we have reviewed the Transitional OFTO regime's development and the policy that was applied to the TR1 projects in terms of price control regime and licensing policy.

At this point it is worth taking a step back to characterise the Transitional OFTO regime in terms of its core economic features as this impacts on the comparisons we make to alternative regulatory frameworks which could potentially have been adopted in GB for offshore transmission.

One	The Transitional OFTO regime has defined offshore transmission as a specific asset class with a dedicated pricing regime and licensing policy for operating and financing individual offshore generation connections. This is largely in contrast to the experience of regulated energy networks to date, where companies undertake various activities across a portfolio of projects within their licensed businesses as part of an integrated network.
Two	The regime has combined elements of ex ante regulation applied to onshore networks with characteristics of regimes observed in other sectors, such PFI (e.g. availability incentives and competitive tenders) . At the same time, the network's development and operation has taken place within the context of the GB electricity market structure, such as the GB System Operator (SO) function, connection offer processes and TNUoS charges.
Three	Of course, a relatively obvious but important point, is that third party involvement in the financing, operation and maintenance of offshore transmission assets has been introduced through the Transitional OFTO regime, along with competitive pressure (rather than solely regulatory cost assessment) being brought to bear on these activities.

3 TENDER ROUND 1 OUTCOMES

Tender Round 1 outcomes

Introduction

In this section we identify:

- The outcomes observed under the Transitional OFTO regime as applied to the TR1 projects. This includes the licence competition process for TR1, financing terms / sources and the approach preferred bidders took in structuring their bids.
- It is these outcomes that we are evaluating through our cost benefit analysis by comparing the Transitional OFTO regime to possible counterfactuals (what those counterfactuals may be is the subject of Section 5).

We show that:

One

There was a strong market response to the TR1 tenders with more than £4bn of capital committed to the nine TR1 projects through the process.

Two

Tender Round 1 tapped into a wide pool of capital which provided a strong foundation for competitively sourcing finance for the whole programme.

Three

A large quantity of project finance was attracted at reasonably keen rates during a period of significant market volatility and uncertainty (the "credit crunch").

Four

While there have been transaction costs, TR1 introduced new transmission service providers to the industry with new contracting/commercial structuring methods.

Tender Round 1 outcomes

Overview of the TR1 outcomes

Background on timing and selected OFTOs:

- The Transitional OFTO regime has been applied to projects that qualified by 31 March 2012 into the tender process and only where the transmission assets have been or will be constructed by the offshore developer, then transferred to an OFTO.
- Ofgem commenced the first transitional tender round of tenders on 22 July 2009 which included nine projects. The table below shows the developer of each project and the preferred bidder in each case, following the completion of the tender process.

Table 3.1: TR1 project developers and selected OFTOs

TR1 project	Developer (s)	Appointed OFTOs
Barrow	Dong Energy / Centrica	Transmission Capital Partners
Robin Rigg	E.On	Transmission Capital Partners
Gunfleet Sands 1 and 2	Dong Energy	Transmission Capital Partners
Sheringham Shoal	StatoilHydro / Stratkraft	Blue Transmission
Ormonde	Vattenfall	Transmission Capital Partners
Greater Gabbard	SSE/Airtricity, RWE Innogy	Equitix, AMP Capital, Balfour Beatty
Thanet	Vattenfall	Balfour Beatty Capital
Walney 1	Dong Energy	Blue Transmission
Walney 2	Dong Energy	Blue Transmission

Figure 3.1: Location of the TR1 projects

1	Barrow
2	Robin Rigg
3	Gunfleet Sands I & II
4	Sheringham Shoal
5	Ormonde
6	Greater Gabbard
7	Thanet
8	Walney 1
9	Walney 2

There was strong investor appetite in TR1 …

There was a strong market response to the TR1 tenders:

- A significant amount of capital (more than £4bn) was committed to the TR1 projects through the bid process by a variety of corporate and project finance debt and equity investors.
- Bids included debt from the European Investment Bank (EIB) and commercial bank financing and equity from investors in the energy sector and international infrastructure more widely.
- Examples of the financial structures adopted for TR1 projects are illustrated below. Appointed licensees typically relied on debt for between 80 per cent and 90 per cent of their financing.

Table 3.2: Illustrative TR1 financing terms[1]

Project	Senior Debt (Gearing)	Terms
Robin Rigg	£65.1m (c. 84%)	19 year tenor (12 month trail) Priced at ~ LIBOR +220-235bp
Gunfleet Sands 1&2	£50m (c. 85%)	19 year tenor Priced at ~ LIBOR +195bp
Walney 1	£105m (c. 85%)	19 year tenor (12 month trail) Undisclosed pricing
Barrow	£35m (c. 81%)	17.5 year tenor Priced at ~ LIBOR +220bp

Table 3.3: Illustrative of debt and equity sources in winning bids

Debt	Equity
nab, BARCLAYS, ING, UniCredit Group, Nationwide, Santander, BNP PARIBAS, European Investment Bank, LLOYDS BANK	AMBER, BARCLAYS Infrastructure Funds, MACQUARIE, Balfour Beatty, equitix, DUTC a subsidiary of Mitsubishi Corporation

Note 1: Source KPMG (2012): 'Offshore Transmission: An Investor Perspective'

Tender Round 1 outcomes

… with finance attracted in a difficult period for financial markets …

General decline in project finance including PFI/PPP deals:

- All of the original ITT bids were received in March 2010 a challenging financing period for infrastructure sectors, including regulated markets and Public-Private Partnerships (PPPs) and PFI schemes….

"2008 and 2009 were challenging years to raise finance PPPs and PFIs in the UK. The number of lenders in the market was significantly reduced, and those that remained toughened their positions. A number of projects found it difficult to reach financial close, and those that did close found that previously offered terms were no longer available."

Source: PPP Solutions (2010)

"The availability of long-term bank lending has continued to contract as banks rebuild balance sheets, respond to new capital requirements and lose their historical appetite for large mismatches between short-term liabilities and long-term assets. This presents challenges in some infrastructure sectors, while others are less affected. "

Source: HM Treasury (2012)

- The volume of PFI / PPP schemes able to reach financial close fell significantly during the credit crunch with 2008 – 2010 a very challenging period to raise finance for these schemes in the UK.
- The number of lenders in the market significantly reduced (reducing the volume of finance that was available) and those that remained toughened their positions. See overleaf.

Tender Round 1 outcomes

… with finance attracted in a difficult period for financial markets …

Not only was liquidity in finance markets generally hit after the collapse of Lehman Brothers in Autumn 2008, but the long term debt market was extremely challenging:

- The number of participants in the London-based project finance market fell by approximately half from forty to twenty and the size of individual lending commitments decreased.
- Banks such as RBS stopped lending longer than seven years and active lenders in the market such as Depfa, Dexia, WestLB and Bank of Ireland just ceased their activities in this area.
- The fragility of the markets is evidenced both by PPP transactions such as the £1.2bn M25 DBFO taking much longer to close than expected and HM Treasury creating a lending scheme called TIFU – Treasury Infrastructure Finance Lending Unit – to deal with market failure in the long term project finance market.

Other evidence of challenging markets was the sale of Gatwick airport:

- This was completed in September 2009 and despite the quality of the asset, did not attract a significant number of bidders due to the difficulty of raising finance and reduced bidder confidence.
- It was reported that the gearing of the winning bid was approximately 55%, less than has been observed for these types of businesses and there was not a premium to Regulatory Asset Base (RAB), which is again unusual for regulated assets in the UK.

… with finance attracted in a difficult period for financial markets …

Observed trends in project finance/PFI deals were also observed in capital markets:

- The figure below illustrates increasing spreads on corporate (A to BBB rated 10-year) debt over the 2007 to 2010 period linked to the volatility in financial markets.

Figure 3.4: UK Investment grade credit spreads on ten year debt [1]

Conclusions? A large quantity of project finance was attracted at an extremely challenging period for the London-based project finance market and debt markets more generally.

- The DRPCR5 price control review being undertaken to similar timescales illustrates the challenges of financing energy networks, as unconventional approaches (such as trigger mechanism for setting the cost of debt) were considered, although not adopted.

Note 1: Source: CEPA analysis of Bloomberg data

… and at relatively competitive financing terms compared to PFI

Margins on PFI deals had been rising leading up to 2010:

- The OFTO tender process for operational assets resulted in project finance being attracted into the sector at relatively keen rates compared to observed margins on PFI deals at the time.

Figure 3.2: Risk premium on OFTO commercial debt

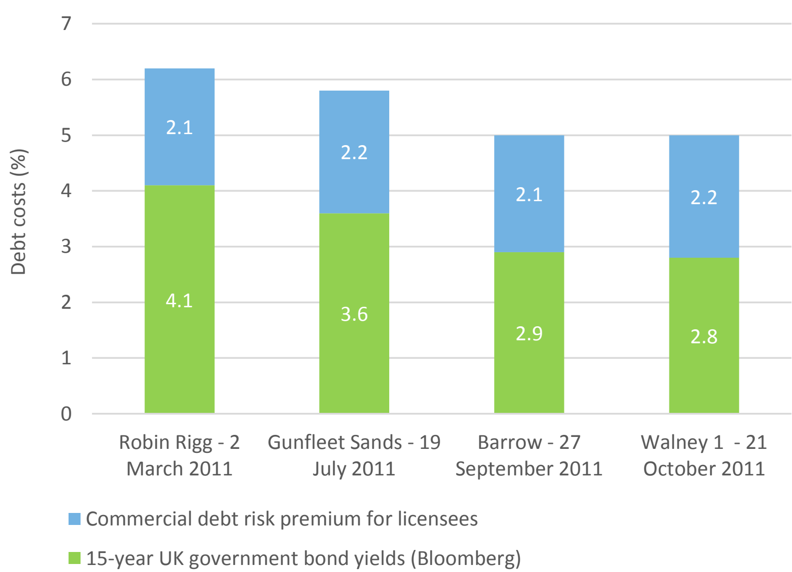
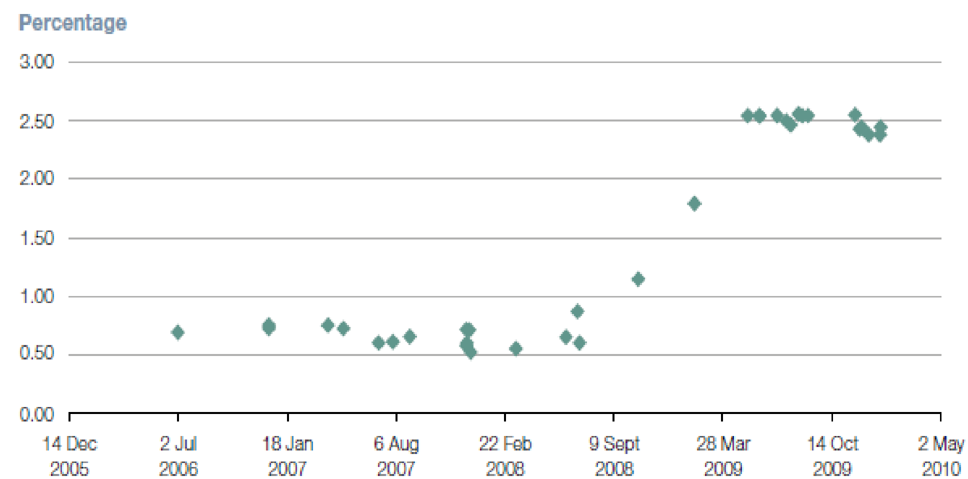


Figure 3.3: Comparison to rates in the PFI market[1]



Source: NAO

- Whilst PFI projects involve construction risk – which would explain a differential in rates – the cost of OFTO debt financing can at least be seen as competitive.

Note 1: Typical changes, after December 2008, in loan margins exemplified by Building Schools for the Future (BSF) projects

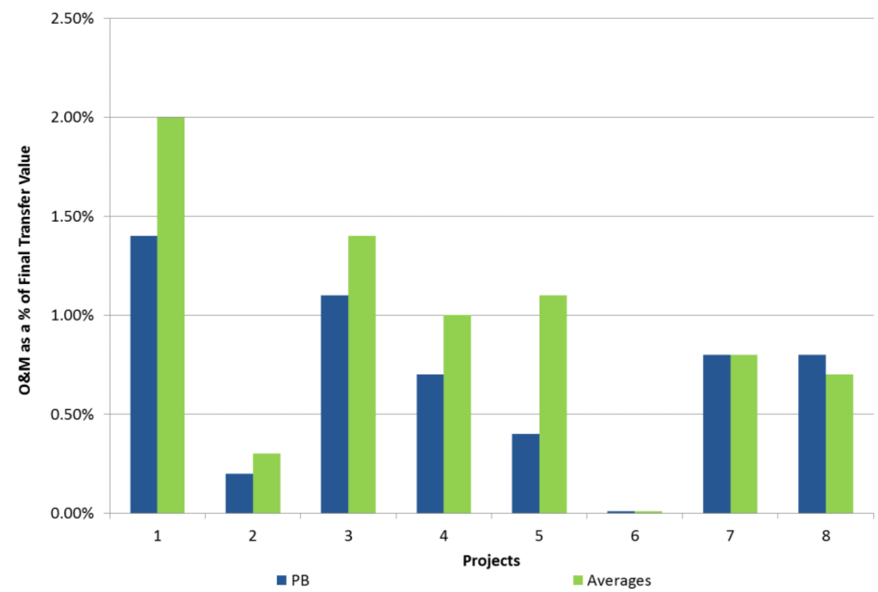
Operational outcomes … TR1 introduced new service providers to the industry

Appointed OFTOs adopted contracting arrangements in line with PFI approaches:

- The appointed OFTOs subcontracted out operational and maintenance (O&M) work, with the risks associated with these activities also passed through to the O&M contractor.
- In the case of a couple of projects, the appointed OFTOs were also able to bid a low O&M by utilising generator developer offers to perform the operation and maintenance work (in one case, this was at nominal cost).
- As with financing, new service providers have been able to enter the market for transmission services with new contracting strategies (e.g. in structuring insurance solutions, management of availability and O&M risks and more general project management) observed in other sectors.[1]

Conclusions? TR1 introduced new transmission service providers to the industry with new contracting/commercial structuring methods.

Figure 3.5: O&M as a % of transfer value under the winning TR1 bids



Note 1: Some bidders subcontracted O&M provision at a fixed price. Others utilised external insurance advisors, who sourced insurance solutions from different sources. As bids progressed, bidders drove down the cost by accepting larger deductibles through self insurance of small events.

Tender Round 1 outcomes

OFTO tender process had common features with public procurement programmes

A structured and standardised programme:

- The OFTO regime has been structured as a procurement programme with tender rounds. This means that short-listed bidders were able to dedicate resources to the process and the “OFTO opportunity” within specific time windows.
- The licensing and tender regulations have also created a standardised approach for the tender process which is again likely to have improved the attractiveness of the opportunity for international investors.

Similar principles have also been adopted for PFI:

Private Finance 2 (PF2)

PFI was introduced in order to engage the private sector in the design, build, finance and operation of public infrastructure. In late 2012, the Government set out a new approach to involving private finance in the delivery of public infrastructure and services through a long-term contractual arrangement, Private Finance 2 (PF2). This continues to draw on private finance and expertise in the delivery of public infrastructure and services whilst addressing past concerns with PFI and responding to the recent changes in the economic context. Part of the proposed reforms apply to risk allocation and programme standardisation. This has included standardisation of PF2 contracts [1] and roll-out programmes of standardised projects to improve investor appetite.

UK infrastructure is competing for finance in an international capital market. The standardisation of the tender rounds may have helped to attract new sources of finance and support financing outcomes discussed previously.

Note 1: See – HM Treasury (Dec 2012): Standardisation of PF2 Contracts

Tender Round 1 outcomes

Tender Round One process outcomes

TR1 attracted high levels of interest for each of the projects:

- In total there were over 67 submission across the nine TR1 projects. 26 companies/ consortia expressed an interest in bidding.
- 3-5 bidders were short-listed for each of these projects with 6 qualifying bidders overall.
- At ITT stage 30 bids were received from 5 bidders after one shortlisted bidder withdrew.
- Ofgem undertook wide market engagement and promotion of the opportunities prior to the tenders commencing.

"The transaction costs, at between £7 million and £8 million for each competition appear high as a proportion of asset value. This partly reflects early deals involving transmission assets with relatively low asset values"

Source: NAO

Table 3.4: Market interest in TR1 tenders

	TR1
Number of licences tendered in TR1	9
Expressions of interest	26
Long-listed bidders	6
Short-listed bidders	6

However, the NAO suggested that transaction costs had been high:

- Ofgem recovers its costs by charging fees to bidders and the generators for running the competitions and arranging the transfer of the assets.
- Generators' transaction costs are added to the price OFTOs pay for the transmission assets. Winning OFTO bidders then recover these, and their own bid costs, through the licence TRS.

Table 3.5: Illustration of preferred bidders' recovered bid costs (real)[1]

Project 1	Project 2	Project 3	Project 4
£4.1m	£6.4m	£4.2m	£5.2m

Table 3.6: Ofgem fees – recovered from all bidders

(£s)	Generator – ex ante	Generator - admin	Bidders – PQ	Bidders - ITT
Value per participant	£51,733	£50,000	£5,000	£50,000

Note 1: These are the total recovered bid costs by the winning bidder (including Ofgem fees). The costs of preparing a bid (including Ofgem fees) cannot be recovered by bidders who fail to be obtain a licence in the tender round.

Tender Round 1 outcomes

Tender Round One timing outcomes

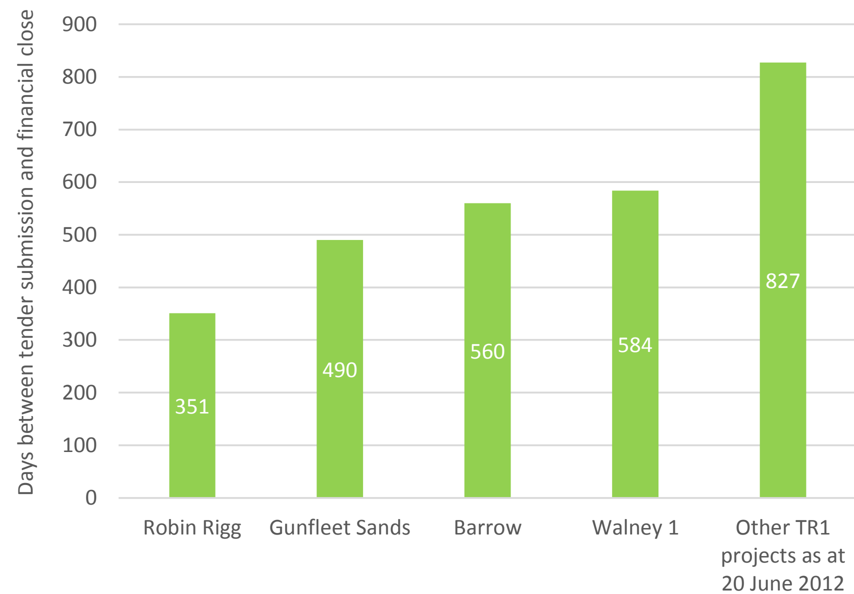
Delays linked to commercial and technical issues:

- TR1 has adopted a very different regulatory process than typical price reviews applied to onshore energy networks.
- The process involved the development of new tender regulations and running of the tender process itself.
- The NAO highlighted that it took Ofgem longer than the 100 days that it indicated in its published tenders with the first four licences awarded between 350 and 600 days after receiving the tenders.
- The last two projects in TR1 only relatively recently reached the point of licence award and financial close or are still outstanding. However, most of the delays are linked to technical and commercial issues including completion and testing of the transmission assets.

"The Authority mainly ran the competitions well but delays happened because wind farm construction was not completed as anticipated."

Source: NAO

Figure 3.4: Time between submitting the tender and licence award [1]



Conclusions? Technical delays are unlikely to have been avoidable. However, in the majority of cases the TR1 process has enabled the projects to reach financial close relatively quickly.

Note 1: NAO (2012): 'Offshore electricity transmission: a new model for delivering infrastructure', Figure 6, p. 25

Tender Round 1 outcomes

A range of favourable outcomes were achieved in challenging circumstances ...

Outcome 1	**A wide source of finance:** A significant amount of capital (more than £4bn) was committed to the TR1 tender process. The regime tapped into a pool of international capital, including debt from the EIB, commercial bank financing and equity from investors in the energy sector and international infrastructure more widely.
Outcome 2	**Projects closed in a difficult market environment:** OFTOs typically relied on debt for between 80 - 90 per cent of their financing. The timing of the TR1 tender process (while not in the late 2008 and early 2009 height of the volatility in financial markets) took place in a period where there were significant constraints on accessing debt markets. Finance was attracted at relatively keen rates during a period of significant market volatility.
Outcome 3	**Recycling of capital:** Whilst a few of the TR1 projects have been delayed for commercial and technical reasons, the generator build and transfer model adopted for the Transitional regime has helped most of the projects reach financial close relatively quickly. The asset transfer process has recycled developer construction capital for use in other sources (e.g. future offshore wind projects).
Outcome 4	**New transmission service providers:** As well as introducing new investors into the energy sector, the competitive based tender regime has introduced new providers of transmission services alongside existing providers in this sector. These new providers have adopted different approaches for managing performance risks (e.g. network availability) and their O&M of the transmission network.

... although there were also associated transaction costs, linked to the new regulatory regime and tender bid costs

4 EVALUATION FRAMEWORK OVERVIEW

Evaluation framework overview

Introduction

In this section we set out:

- The cost benefit evaluation framework that we have developed and applied to the TR1 projects that have been delivered through the Transitional OFTO Regime.
- This covers the ‘building blocks’ of our approach and the modelling methodology and assumptions that we have used to evaluate the regime and its observed outcomes.

Our approach is to develop counterfactuals to TR1 through building block analysis of the costs and the benefits (e.g. avoided costs) of and comparing this to the outcomes observed under the Transitional OFTO Regime. We show that:

One

Counterfactuals are internally coherent scenarios of what alternative policies *might* have reasonably been expected to be implemented in the absence of the OFTO regime.

Two

Our approach is consistent with HM Treasury Greenbook guidance. We identify what is being evaluated and what we are comparing to (the counterfactuals).

Three

We seek to quantify the costs and benefits that have been delivered under the Transitional OFTO regime as compared to our counterfactuals.

Four

As a final step in the analysis we also consider the distributional issue of who may have benefitted from cost savings achieved by the Transitional OFTO regime in TR1.

What is a counterfactual?

- In this context, the counterfactuals are internally coherent scenarios of what alternative policy options might have reasonably been expected to be implemented in the absence of the adopted policy.
- The objective of our analysis has not been to identify what would be the most likely counterfactual to the policy that was actually implemented, but rather to seek to identify a broad range of *possible* counterfactuals which help identify the potential quantum and sources of benefits *and* costs, and how those costs and benefits may have been distributed between industry parties.
- With this objective in mind, we have developed a range of counterfactuals and associated assumptions and sought to test the findings from the cost benefit analysis through sensitivity analysis of the key assumptions.

Quantifying the counterfactuals:

- Quantification of the outcomes from the counterfactuals need to take into account what would have been most likely observed at the time, together with what has happened to date and what might happen in future.
- In other words, the greater the amount of historical information available between the introduction of the policy and when it is being evaluated the better the quantification of any benefits.
- However, it is the differences in outcomes with the actual policies (in this case the Transitional OFTO regime and associated regulatory and commercial arrangements) which are of most importance in terms of policies.

Evaluation framework overview

How are the counterfactuals used in the cost benefit analysis?

We have developed our approach to be consistent with HM Treasury Greenbook guidance:

- As described above, as a first step we have sought to establish what is to be evaluated and developed a set of counterfactuals to the Transitional OFTO regime in practice applied to TR1 offshore transmission projects.
- We then quantify the cost savings from the TR1 projects having been delivered under the competitive Transitional OFTO regime as compared to if they had been delivered under a counterfactual.
- We have then sought to ***identify*** the source of the cost savings, for example from financing cost or operating cost savings, as compared to the counterfactuals. We have also considered wider issues, such as financial deliverability.
- Finally we consider the more indirect benefits that may be realised from the TR1 process (e.g. price discovery) and the *distribution of benefits* (i.e. *who* may have benefitted from savings in our cost benefit analysis).

We adopt a building block approach to the analysis:

- We have developed assumptions on financing costs, operating costs, transaction costs and taxation for each of the counterfactuals which are compared to equivalent cost proportions of the TRS in the appointed OFTO bids for each of the TR1 projects.
- This helps identify the potential source of any benefits which may have been realised from the Transitional OFTO regime's application to the TR1 projects, when compared to the counterfactuals.

There are a number of key assumptions which underpin the analysis

The scope of analysis applies to the operational phase of the TR1 projects:

- As explained in Section 2, the Transitional OFTO regime was applied to TR1 project generation connections, as the developers of these projects had at the time already started one or all of: award of construction contract and construction works.
- It was, therefore, not considered an option that these generation connection projects could have been constructed by a party other than the offshore wind farm developer.
- For the purposes of our analysis of TR1 projects, we have, therefore, assumed that a similar principle would have applied to counterfactuals to the Transitional OFTO regime.
- We assume the Final Transfer Value (FTV) for the projects tendered under TR1 applies under all counterfactuals. This means that in the case of alternative *regulated* counterfactuals, we assume that the same cost assessment process would have been applied by Ofgem to establish the FTV of these projects.

Our analysis assumes that under all alternative states of the world, the **offshore wind farm developer** would have developed and constructed the TR1 offshore transmission assets (including financing during construction), but there were alternative approaches that could have been adopted for the maintenance and the financing of the transmission assets once they were operational.

Evaluation framework overview

The modelling methodology addresses all counterfactuals on a like-for-like basis

First, we calculate the total Net Present Value pricing of the nine TR1 projects:

- We use bid data on each project provided to us by Ofgem[1] on the breakdown of individual cost items (e.g. financing costs, O&M expenditure, transaction and management (e.g. Special Purpose Vehicle related costs)) as a percentage of the final annual TRS.
- These figures are projected to apply across the full 20-years of the OFTO licence for all the transmission projects which were included in TR1. This results in a total real projected pricing base for each TR1 project, broken down by cost categories.
- The real pricing base for the TR1 projects, by individual cost item, is then converted into Net Present Value totals for the TR1 tender round. The cost benefit analysis is, therefore, undertaken in NPV terms and based on the TRS which were **bid** by the appointed OFTOs, rather than their outturn costs.

We then model the counterfactuals as follows:

- We model the **pricing** of transmission services under the counterfactuals, **not** actual costs. It is what users would have paid for the transmission services, given how prices will have been set, which matters for the cost benefit analysis.
- Counterfactual operating costs are modelled as a constant percentage assumption of the TR1 projects transfer value over the assumed economic life of the projects (20-years).
- In all counterfactuals the assets are straight line depreciated over 20-years and the average asset base is used to calculate the return on the investment under the counterfactuals, applying a Weighted Average Cost of Capital (WACC).
- We model the return on investment to approximate continuous discounting and a simplified tax allowance calculation is used to approximate counterfactual tax, based on the principles Ofgem adopts for onshore network price control reviews.

Note 1: We have not sought to independently verify the assumptions and calculations used by Ofgem to develop this breakdown of cost items.

The modelling methodology comprises four key components

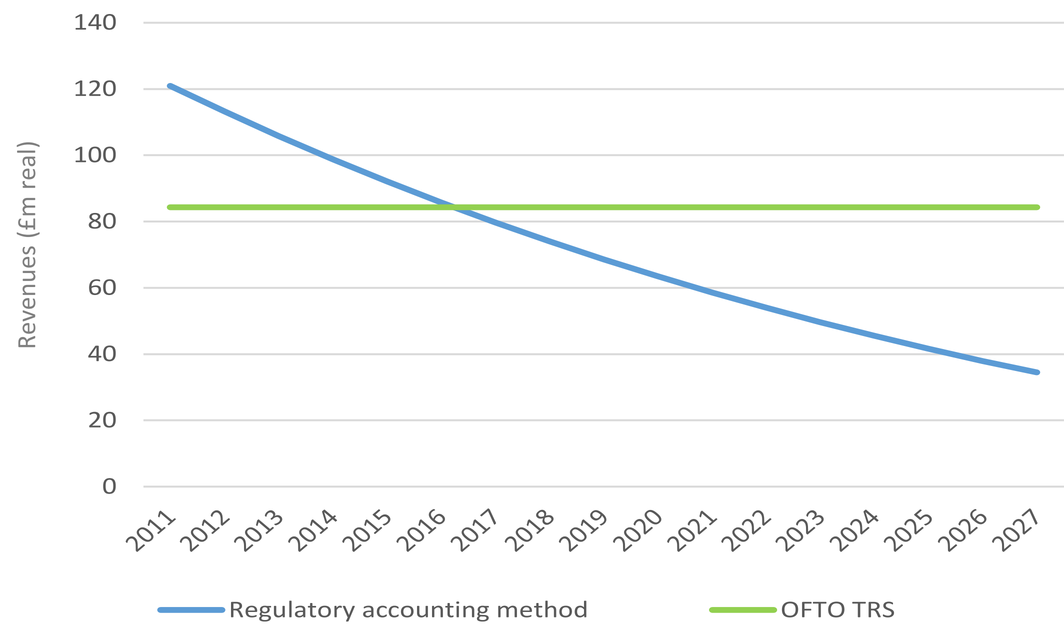
Financing costs	We have modelled counterfactual financing costs through developing assumptions of the cost of capital. This is based on a review of market evidence of financing rates at the time, and an assessment of the relative risk profiles of counterfactuals. Our assumptions are detailed in Section 5.
Operating costs	We develop assumptions on operating costs (e.g. O&M) for each of the counterfactuals by comparing OFTO preferred bidder operating costs to other TR1 bidders proposed operating costs. We also consider other published benchmarks of offshore O&M in developing input assumptions to the modelling. Our assumptions are detailed in Section 5.
Tax	To model counterfactual tax, we adopt a simplified tax allowance calculation based on similar principles to those Ofgem adopts for allowing for tax in onshore network price control reviews. This involves making simplifying assumptions on tax pools and treatment of tax under the counterfactuals.
Bid costs	Our assumptions on counterfactual transaction costs are also developed from TR1 bid data. We include bid costs and public tendering costs in counterfactuals which involve competitive bidding. Other counterfactuals are assumed to not include bid related costs.

The modelling methodology takes into account differing revenue profiles

- The approach we take to modelling financing costs for the counterfactuals generates a different profile of cash flows compared to the constant real TRS applied for the TR1 projects under the Transitional OFTO regime.
- This arguably has implications for the investor risk profile as it impacts on funding profile of the investment.
- It also has a discounting effect when comparing the Net Present Value of TR1 costs to counterfactual costs.
- This is an outcome of the funding profile which is assumed in the counterfactual modelling as compared to the TRS funding principles which have been adopted for OFTO licences.

These assumptions drive the profile of cash flows in our counterfactuals.

Figure 3.1: Profile of revenues OFTO regime vs. counterfactuals



The indirect benefits and distributional impacts of the outcomes from the OFTO regime compared to the counterfactuals are also considered

Distribution analysis:

- The methodology set out above is intended to provide an analysis of the cost savings that may have been realised under the Transitional OFTO regime compared to alternative delivery mechanisms.
- This does not, however, answer the question of *who* may have benefited from any cost savings which the contestable OFTO regime may have achieved compared to counterfactuals.
- We seek to answer this question by considering interactions between the form of network regulation, cost recovery arrangements (e.g. TNUoS charges) and market arrangements for offshore wind generation. This is the focus of Section 7.

Indirect benefits:

- We also consider "price discovery" to be a potential benefit of the competitive approach which was followed in TR1, since it relates to dynamic impact of contestable projects on future offshore projects.
- This is particularly important as offshore transmission still faces strong cost and technology uncertainties, and an objective to drive down industry costs (see discussion in the introduction of the report on DECC's energy roadmap and the Crown Estate pathways study for the UK offshore wind sector).
- We analyse price discovery benefits through considering the impact that lower offshore transmission costs could have on future transmission charges and offshore wind subsidies.

5 COUNTERFACTUALS

Introduction

In this section we develop:

- The counterfactuals to the Transitional OFTO regime that could in practice have been applied to the TR1 projects. These form the basis for our comparative Cost Benefit Analysis against the outcomes under the Transitional OFTO regime.
- We adopt a three-stage approach for establishing counterfactuals. First, we identify a long list of possible scenarios. We then review each of the scenarios against a set of criteria to develop a short-list of what we consider to be the most feasible and practicable scenarios.
- As a third step, we take a view on the possible cost parameters that may have applied under each counterfactual, for example, the counterfactual cost of capital.

We show that:

One	Our counterfactuals start from two central alternatives to the OFTO regime: alternative licensed price control based approaches; and licensed merchant solutions.
Two	We develop two counterfactuals for the merchant solution: one involving the generator owning the assets; the other involving a sale and lease back arrangement
Three	We develop three short-listed counterfactuals under a price control based approach, two involve extending existing TO licences and one involves a zonal offshore licensing regime.
Four	Our counterfactuals are based on what were considered to be the most likely alternatives to the OFTO regime at the time (see Section 2 and Annex A).

A long-list of counterfactuals has been developed around two core models …

Identifying practicable and realistic alternative states of the world:

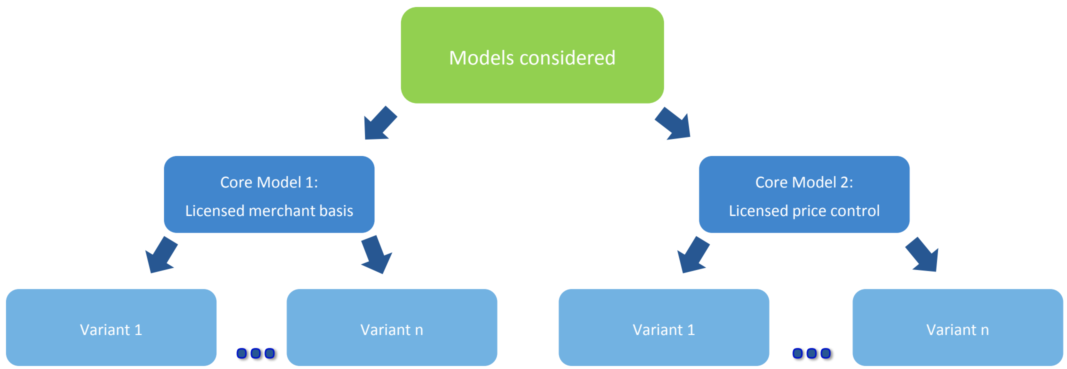
- As discussed above, in determining counterfactuals we need to strike a balance. On the one hand the counterfactuals need to cover a wide enough range of possible arrangements in order to capture all potential costs and benefits. One the other hand they should be realistic regimes and concise enough for effective analysis.

Our approach starts from two central alternatives to the implemented Transitional OFTO regime:

- Offshore transmission delivered through a **licensed**[1] **merchant** solution; and offshore transmission delivered under alternative **licensed price control arrangements.** We believe these two scenarios together cover a wide range of realistic alternative regimes, including the options that were originally considered at the time of the OFTO regimes development (see Annex A).

We consider possible variants of regime under each of these two core models.

Figure 5.1: Two broad models used to develop counterfactuals



Note 1: We rule out a licensed exempt merchant led approach as this was not considered legally feasible by the Government at the time.

… a licensed price control approach and a licensed merchant approach

Table 5.1: Variants of two core counterfactual models

Variant	Description
Licensed merchant approach	
Variant 1	Offshore transmission is licensable, but offshore generation developer responsible for DBFO of assets. Financing arrangements are an entirely commercial relationship between licensee and generator internal to the wind farm project.
Variant 2	Licensed merchant approach, but the developer operates a sale and lease back arrangement for the assets having constructed them with the offshore wind farm assets. Funding arrangements remain a purely commercial agreements between the generator and the lessor.
Licensed price control approach	
Variant 1	Onshore TOs have exclusive licence extended offshore with offshore transmission services included in existing onshore price control arrangements.
Variant 2	Onshore TOs have exclusive licence extended offshore, but a dedicated offshore price control is applied to the offshore assets and services.
Variant 3	Offshore area is broken into zones ('multi-zone' approach), where TOs are obligated to develop connections within a zone.
- 3a	- the multi-zone licenses are awarded through a competitive tender.
- 3b	- the multi-zone licences involve fixed price control parameters at licence award.
- 3c	- multi-zone licences involve flexible price control parameters and price reviews.
Variant 4	An exclusive licensing approach (e.g. like Variant 3) but the generator selects the TO ("generator tender approach").
Variant 5	Transitional OFTO regime with alternative charging arrangements.

Counterfactuals

The counterfactuals have been shortlisted by applying criteria

- **These are as follows:**
  - **legal consistency** – with legal arrangements, in particular European directive requirements under the Internal Market Electricity Directive (IMED), the Renewables Directive and the Third Energy Package;
  - **precedent** – has the approach been implemented elsewhere in the world (either in the context of offshore transmission or in other sectors and industries);
  - **regime consistency** – consistency with GB energy policy and the wider regulatory framework which applies to electricity transmission and markets in GB; and
  - **practicality** – is the approach a realistic regime and, therefore, a realistic counterfactual for the Transitional OFTO regime (e.g. given the policy context of the time).
- Our assessment is based on a relatively simple tick based system with one tick being worst and three ticks best. We have then used a traffic light system to identify options to consider further in the short list, which are the options with a green traffic light.
- Options that are identified as red and orange are not considered further, although those with an orange assessment have some intrinsic merit.

Our assessment of the long-list of counterfactuals is presented overleaf

Counterfactuals

Table 5.2: Assessment of long-list of counterfactuals

Counterfactual	Legal consistency	Regime precedent	Regime consistency	Regime practicality	Overall assessment	Examples?
Licensing merchant approach						
Variant 1	✓ [1]	✓✓	✓✓	✓✓✓	Shortlisted	Offshore gas and oil networks; gas and electricity interconnectors
	Description: licensed merchant based regime where generator owns the assets – no price controls.					
Variant 2	✓✓✓	✓✓	✓	✓✓✓	Shortlisted	
	Description: as per Variant 1 but developer operates a sale and leaseback arrangement with a third party provider.					
Licensed price control approach						
Variant 1	✓✓✓	✓✓✓	✓✓✓	✓✓✓	Shortlisted	Transmission Price Control Review (TPCR) 4
	Description: onshore TO adopts offshore transmission assets once operational.					
Variant 2	✓✓✓	✓✓✓	✓✓✓	✓✓✓	Shortlisted	TII ; Strategic wider works
	Description: as per Variant 1 but with dedicated offshore price control regime.					
Variant 3a	✓✓✓	✓✓	✓✓✓	✓✓	Shortlisted jointly with variant 3c	Roll-out of the Northern Ireland gas network
	Description: "multi-zone" offshore licences potentially awarded through a competitive tender process.					
Variant 3b	✓✓✓	✓✓	✓✓	✓		
	Description: as per Variant 3a but with fixed price control parameters.					
Variant 3c	✓✓✓	✓✓✓	✓✓✓	✓✓	Shortlisted jointly with variant 3a	
	Description: as per Variant 3a but with flexible price control parameters (i.e. price reviews).					
Variant 4	✓✓✓	✓	✓	✓		
	Description: an exclusive licensing approach but the generator selects the TO.					
Variant 5	✓	✓✓✓	✓	✓✓✓		Various other TNUoS pricing regimes
	Description: the Transitional OFTO regime with alternative charging arrangements.					

Note 1: Given Third Package requirements it is arguable whether a generator led merchant approach would have been legally practicable.

We created a short-list of counterfactuals for further development

Table 5.3: Short-listed counterfactuals

	Counterfactual	Description
1	A licensed merchant approach for developing and operating the TR1 assets	The offshore generator is responsible for design, build, finance and operation of the assets with financing arrangements an entirely commercial relationship internal to the wind farm project.
2	Variant of the licensed merchant with a sale and lease back arrangement	A variant of the licensed merchant approach. The generation developer designs and constructs the assets, but a sale and leaseback arrangement is introduced for the ownership and operation of the transmission assets.
3	Onshore TO led ownership of TR1 assets with a joint onshore and offshore price control	Onshore TOs have their exclusive onshore transmission licences extended offshore, and the offshore transmission services are included within the existing onshore price control arrangements.
4	Onshore TO led ownership of TR1 assets with a specific offshore price control	Onshore TOs have exclusive onshore transmission licences extended offshore, but a dedicated offshore price control is applied to the offshore assets and offshore services.
5	Appointed offshore zonal TO to own TR1 assets with a specific offshore regime	Exclusive multi-zone licences where the TO is licensed (potentially through a competitive tender) for an entire offshore zone and obligated to develop any future connections to shore (TR1 assets are adopted as operational).

- Whilst we consider these to be the most relevant counterfactuals (given the alternatives to the OFTO regime considered by Ofgem and the UK Government at the time) we believe some would have been more executable than others.

We now turn to the design / assumptions for each of the short-listed counterfactuals as well as more practical considerations such as financial deliverability of the counterfactual.

Each counterfactual has a commercial / regulatory regime

For each short-listed counterfactual this includes:

- Who designs, builds, finances/owns and operates the offshore transmission assets.
- How the network would have been expected to develop under each regime, including:
  - Who has the obligation to provide incremental connections and develop the offshore network.
  - The jurisdiction of the awarded offshore transmission licences (e.g. a whole offshore zone, extension of onshore licence area or transmission asset specific).
- At a very basic level, the determination of the regulatory/commercial terms for offshore transmission services, including:
  - the role of price controls;
  - form of economic regulation (e.g. ex post vs. ex ante);
  - the role of competitive tendering; and
  - the methodology used for transmission charging (if applicable).

Not all of these parameters are necessary critical to the quantitative findings from our cost benefit analysis given that in some cases there may not be any change from the outcomes under the Transitional OFTO regime.

However, they are also provided to aid the description/picture of what each counterfactual could have entailed compared to the observed outcomes under TR1.

Each counterfactual has a commercial / regulatory regime

Table 5.4: Short-listed counterfactual regime features

Element	Transitional OFTO regime	Counterfactual 1 – merchant approach with generator ownership	Counterfactual 2 – merchant approach with sale and lease back	Counterfactual 3 – onshore TO led with joint onshore/offshore price controls	Counterfactual 4 – onshore TO led with specific offshore regime	Counterfactual 5 – multi-zonal offshore licensee regime with specific price controls
Activities						
Design	Generator	Generator	Generator	Generator	Generator	Generator
Build	Generator	Generator	Generator	Generator	Generator	Generator
Finance / Own	OFTO	Generator	Lessor	TO	TO	Offshore TO
Operate/Maintain	OFTO	Generator	Lessor	TO	TO	Offshore TO
Network development						
Incremental connections	Project based	Developer led	Developer led	TO	TO	Offshore TO
Licence jurisdiction	Asset specific	Asset specific	Asset Specific	Onshore extension	Onshore extension	Offshore multi-zonal
Economic regime						
Price controls?	Yes	No	No	Yes	Yes	Yes
Price reviews	No	No	Potentially	Yes	Yes	Yes
Cost recovery	TNUoS charges	Through wind farm	By lease back contract	TNUoS charges	TNUoS charges	TNUoS charges
Form of regulation	Ex ante	Not applicable	Not applicable	Ex ante	Ex ante	Ex ante
Form of regime	Revenue cap	Part of wind farm	Lease back terms	Revenue cap[1]	Revenue cap[1]	Revenue cap[1]
Duration	Fixed TRS	Part of wind farm	Lease back terms	Price reviews	Price reviews	Price reviews
Constestability	Yes	Potentially	Potentially	No	No	Potentially

Note 1: Regime based on onshore price control principles (in the case of counterfactual 3) or designed specifically for offshore assets (in the case of Counterfactual 4 and 5).

Each counterfactual has a different risk allocation

The table below analyses the resulting risk allocation under each counterfactual:

Table 5.5: Short-listed counterfactual risk allocation

Source of risk	Transitional OFTO regime	Counterfactual 1 – merchant approach generator ownership	Counterfactual 2 – merchant approach with sale and lease back	Counterfactual 3 – onshore TO led with TPCR4 applied offshore	Counterfactual 4 – onshore TO led with specific offshore regime	Counterfactual 5 – multi-zonal offshore licensee regime
Incremental capex risk	OFTO	Generator	Lessor	TO [1]	TO [1]	Offshore TO [1]
Operational risk	OFTO	Generator	Lessor	TO [1]	TO [1]	Offshore TO [1]
Availability risk	OFTO	Generator	Lessor	TO [1]	TO [1]	Offshore TO [1]
Payment / Counterparty risk	NETSO	Generator	Generator	NETSO	NETSO	NETSO
Inflation risk	Gen. / Consumer	Internal to Gen.	Lessor terms	Gen. / Consumer	Gen. / Consumer	Gen. / Consumer
Demand risk	Gen. / Consumer	Generator	Generator / Lessor *	Gen. / Consumer	Gen. / Consumer	Gen. / Consumer
Stranding risk	Gen. / Consumer	Generator	Generator / Lessor *	Gen. / Consumer	Gen. / Consumer	Gen. / Consumer
Financing risk	OFTO	Generator	Lessor	TO	TO	Offshore TO [1]
Tax risk	OFTO	Generator	Lessor	TO/consumer [1]	TO/consumer [1]	Offshore TO /consumer [1]

Note 1: See overleaf for further discussion

* subject to terms of sale and lease back arrangement

- We analyse the resulting risk profile for the investor in the transmission assets under each counterfactual overleaf. This analysis is driven by the assumptions we make above on counterfactual regime design and implementation.

Assessment of the counterfactual risk profiles

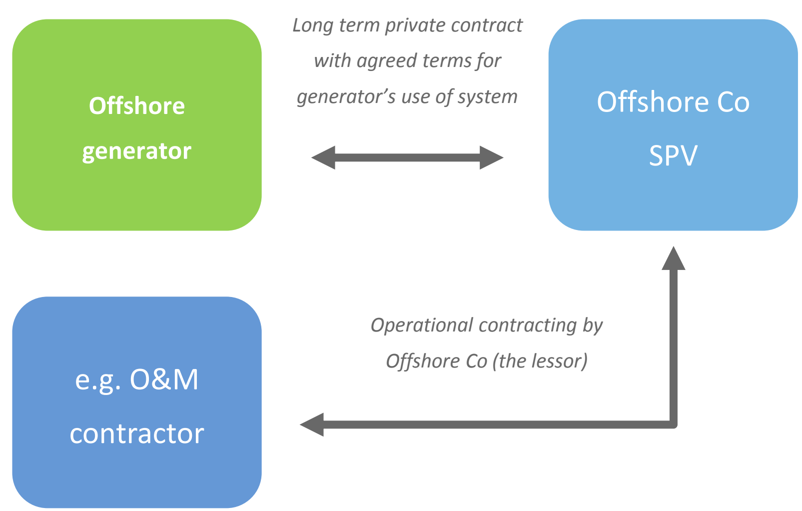
Price control based counterfactuals:

- Counterfactuals 3 – 5 exhibit a *similar* risk profile to the OFTO regime. The owner of the offshore transmission assets has no exposure to the connecting wind farm and receives its revenues from the GB NETSO. The differences in risk profile across these three counterfactuals reflect differences in the licensing policy and the approach to regulation that is applied (see overleaf).

Merchant counterfactuals:

- Under the merchant led approaches, the performance of the transmission investment is more closely linked to the underlying performance of the offshore wind farm.
- With Counterfactual 1, the performance of the investment in the transmission assets is directly linked to the performance of the offshore wind farm.
- With Counterfactual 2, while the lessor's revenues may not be directly linked to the wind farm[1], payment/counterparty risk is higher as the wind farm is the lessor's counterparty.
- The terms of the contract under Counterfactual 2 would need to have been enforced by contract law rather than under a regulatory driven licensing process (see Figure 5.2).

Figure 5.2: Possible sale and lease back "merchant" contracting model



Note 1: A pure "merchant" (rather than fully contracted) led transmission arrangement might expose the investor (to a degree) to volume risks arising from a generator's usage of the transmission asset.

Description of counterfactual risk profiles

The regulated price controlled counterfactuals exhibit a *similar* risk profile as the OFTO regime …

- Counterfactuals 3 to 5 involve regulatory underpinning of the investment in operational transmission assets, as the activities would have formed part of price controlled activities regulated by Ofgem.
- This means that, similar to onshore transmission, investors may have, to an extent, been protected from stranding risks (see discussion of risk profile below) through the enforcement of regulated licence terms.
- We have also made the simplifying assumption that the availability incentive mechanism that applies under Counterfactuals 3 – 5 would have been similar in structure to the TR1 availability incentive.
- This means that penalties under the incentive are capped at a percentage of revenues and are not directly linked to the consequential loss of the generator should the assets fail.

… the differences relate to whether the risk profile of the operational assets can be isolated from wider licensed activities.

- Counterfactuals 3 and 4 would, however, have involved the operational assets forming part of existing TO licensed activities. The perception of investor risk profile would have depended on whether the risks, and the associated return requirements, of these activities could have been isolated from other activities, for example, through a separate price control arrangement for operational offshore assets as, for example, could have been the case under Counterfactual 4.
- Whilst the TR1 assets adopted are operational, Counterfactual 5 would have involved a far more complex business undertaking (current and future operation and development of an offshore zone) than the asset-specific Transitional OFTO regime.

Cost of capital methodology

Having developed the counterfactual regimes, we apply relative risk analysis, evidence of financial market data at the time and current / past regulatory precedent, to develop possible assumptions for the cost of capital for each of the counterfactuals. This is then used to model returns for each counterfactual.

Gearing	We make a qualitative assessment of gearing for each counterfactual, based on relevant regulatory comparators and evidence of gearing in similar sectors and projects.
Cost of Debt	We develop cost of debt assumptions by considering regulatory precedent and possible credit ratings for each counterfactual and what this would imply for the cost of debt based upon historical spread data.
Cost of Equity	We develop cost of equity assumptions for each counterfactual primarily through applying the Capital Asset Pricing Model (CAPM). We consider the relative risk of each counterfactual to develop our assumptions.

Counterfactual gearing assumptions

The range of gearing assumptions for each counterfactual are based on general regulatory precedent and market evidence of gearing levels achieved by infrastructure projects.

- The assumption for Counterfactual 1 is consistent with the gearing levels which we understand UK offshore wind farms have been able to achieve in practice.
- In Counterfactual 2, the sale and leaseback approach, we assume the assets would be relatively highly geared to reflect a project finance solution for the individual sale and lease back projects.
- Counterfactuals 3,4 and 5 are based on gearing levels which assume corporate financing given the nature of the licensed activities and the owner of the assets.
- For Counterfactual 3 we use the notional gearing level currently and previously adopted for National Grid Electricity Transmission (NGET), whilst a range for Counterfactuals 4 and 5 reflects uncertainty of what would have been allowed in the price control.

Table 5.6: Proposed gearing assumption ranges for counterfactuals

	Counterfactual 1		Counterfactual 2		Counterfactual 3		Counterfactual 4		Counterfactual 5	
Range	Low	High	Low	High	Low	High	Low	High	Low	High
Gearing (%)	60%	60%	70%	80%	60%	60%	50%	60%	50%	60%

Developing counterfactual cost of debt assumptions

To develop assumptions on the cost of debt, we first make an assessment of the credit rating of our counterfactuals relative to the OFTO regime. The OFTO report conducted by Moody's stated the following:

> *"'The risk profile of an OFTO that is responsible for construction of the infrastructure will be much higher than that which acquired an already operating asset. Construction risk would have to be well mitigated in order to achieve an investment grade rating.'*

Source: Moody's

- Whilst the transmission asset is relatively passive and is expected only to require relatively routine operation and maintenance, the offshore locations adds complexity to any work required and leads to greater cost volatility.
- In terms of broader ratings methodologies, the credit rating agencies also take into account the type of financing (corporate or project finance), whether a non-recourse basis or project sponsor, and a single asset or multiple.
- The extent to which these factors clearly differ across each of the counterfactuals is accommodated within our overall credit rating assessment for each counterfactual which, as well as the approach to regulation, drives differences in cost of debt figures used in our CBA.

Note: Most electricity generation assets fall in the BB to BBB- ratings, according to the Moody's Power Generation Rating Methodology. However, we know TR1 related projects have been financed on balance sheet by companies with investment grade credit ratings. This is accommodated in the overall cost of capital ranges we develop for Counterfactual 1.

BDO

Counterfactual credit rating assessment

Key

⬇ Lower rating than OFTO regime

Table 5.6: Counterfactual credit rating assessment

Regulatory Factors	OFTO regime	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4	Counterfactual 5
Factor 1 – Regulatory environment and asset ownership model						
Stability and predictability of regulatory regime	AA	⬇	⬇	⬄	⬄	⬄
Asset ownership model	AA	⬇	⬇	⬄	⬄	⬄
Cost and investment recovery	A	⬇	⬇	⬄	⬄	⬄
Revenue risk	AA	⬇	⬇	⬄	⬄	⬇ [1]
Factor 2 – Efficiency and execution risk						
Cost efficiency	BBB	⬄	⬄	⬄	⬄	⬄
Scale and complexity of programme	AA	⬇	⬇	⬇	⬄	⬇
Factor 3 – Stability of business model and financial structure						
Pursue opportunistic corporate activity	AAA	⬇	⬇	⬄	⬄	⬄
Increase leverage	AA	⬇	⬇	⬄	⬄	⬄
Targeted proportion of profit outside core regulated activities	AAA	⬇	⬇	⬄	⬄	⬄
Factor 4 – Financeability metrics						
Financeability ratios	Depends on capital structure	⬇	⬇	⬄	⬄	⬄
CEPA estimate of credit rating	BBB+ to A-	BB- to BBB+	BB- to BB+	BBB+ to A-	BBB+ to A-	BBB+

Note: this is a principles based analysis as CEPA and BDO are not ratings experts. However, we have used the above to support the counterfactual modelling assumptions.

Note: Based on Moody's assessment framework of the offshore regime (itself founded upon the onshore credit rating assessment methodology, categories as above).

Note 1: Assumption based on the potential impact of long term offshore transmission programme delivery risks.

Counterfactuals

Debt finance in the counterfactuals would have needed to be arranged and raised in the period 2009 to 2010

As discussed in Section 3, whilst this was not the height of the "credit crunch" it was still a period of volatility for both credit and capital markets. The rates observed around this period are what is most applicable to the counterfactuals.

There is uncertainty of the timing when the debt would have been raised, when the rates would have needed to be fixed (e.g. the margin to benchmark gilts) and how the cost of debt would have been accounted for in regulatory determinations.

- Ofgem commenced TR1 on 22 July 2009 – this provides one option for setting the date around which the cost of debt would have needed to be fixed.
- The ITT bids for TR1 were received in March 2010 and, therefore, a period towards the end of 2009 / early 2010 could also be considered a relevant counterfactual.
- Where the cost of debt used in pricing the counterfactual is set as a regulatory allowance, there is the added complication of how the regulator would have accounted for uncertainty of the actual cost of debt through its regulatory approach.

To develop ranges for the counterfactual cost of debt, we therefore combine the findings from the relative risk / credit rating assessment for each counterfactual (see Table 5.6) with market evidence of spot / historic rates in the period 2009 – 2010. We also consider alternative regulatory approaches that could have been applied for setting an allowed cost of debt in price controls.

Debt finance in the counterfactuals would have needed to be arranged and then raised in the period 2009 to 2010

The uncertainty of the timing when the debt would have been raised and the interest rates fixed matters because of the volatility in the cost of debt over the period 2009 to 2010.

This is illustrated in Table 5.7 below which shows the year average iBoxx non-financial corporate indices of A and BBB ratings with 10yr plus maturity (approximately 18.5yrs) for 2009, 2010 and 2011.

Table 5.7: Market evidence on the cost of debt (rates at the time)

Cost of debt (real) – year averages	2009	2010	2011
A rated debt, iBoxx 10yr+ index NFCs	3.24%	2.24%	2.13%
BBB rated debt, iBoxx 10yr+ index NFCs	4.56%	2.57%	2.34%
Combined iBoxx 10yr+ index NFCs	3.90%	2.40%	2.23%

Source: CEPA and BDO analysis of iBoxx data

The volatility in debt markets in the period 2009 to 2010 is one of the reasons we adopt ranges for the cost of debt and subject the cost benefit analysis to sensitivity analysis (see Section 6).

Setting a regulatory allowance for the cost of debt

One option for the price controlled counterfactuals would be to assume Ofgem would have adopted a similar approach as it has adopted for other energy network price controls both at the time and subsequently as part of RIIO-T1.

- Under this approach the allowed cost of debt assumption in the WACC may have been based on a simple 10-year trailing average index.
- This would be a continuation of the type of approach applied under TPRC4, the roll-over of TPRC4 and the adoption of a debt indexation approach in RIIO-T1.
- It would have meant that the *allowed* cost of debt for the offshore transmission assets under price controlled counterfactuals, would have been different from the spot rates observed around the time when the TR1 process started and finance would have been raised.
- Modelling this approach in the CBA requires an assumption of how the index would develop over the 20-year licence period.

Figure 5.3: iBoxx GBP Non-Financials indices of 10+ years maturity[1]

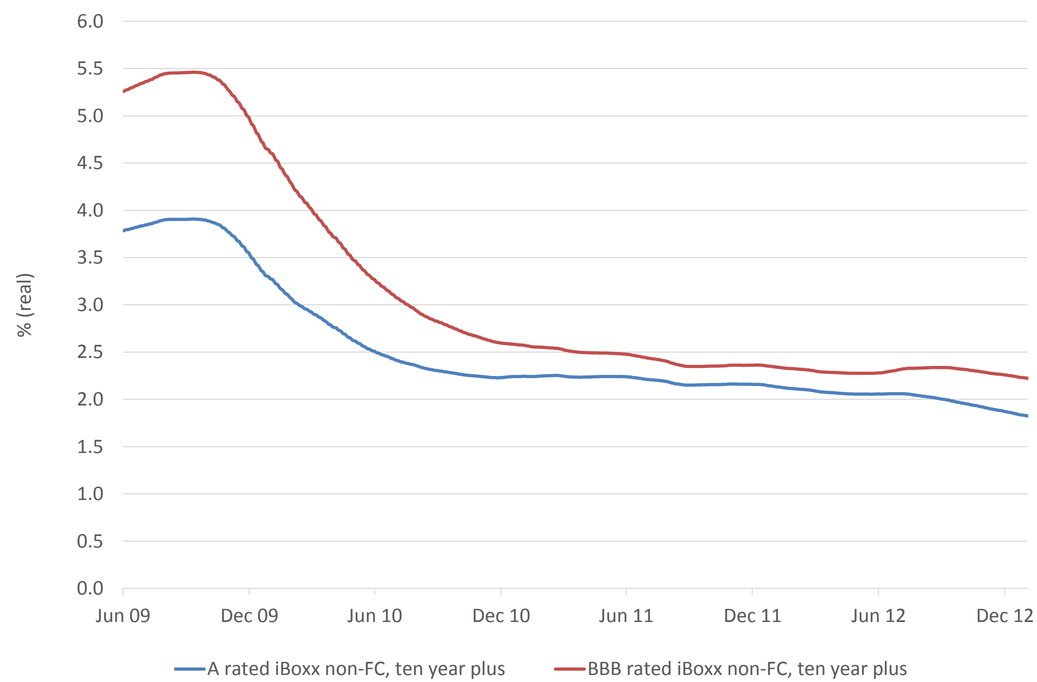
Note 1: Source: CEPA and BDO analysis of iBoxx data

Setting a regulatory allowance for the cost of debt

An alternative approach for the regulated price control counterfactuals would be to assume an individual deal would have been negotiated as part of a dedicated price control for the offshore transmission assets.

- This approach may have taken greater account of spot rates and recent historic rates observed during 2009 and the early 2010 period.
- The allowed cost of debt assumption may have reflected what was considered a reasonable embedded cost of debt allowance for the project at the time.
- This allowance could either have been fixed for the entire licence period – to reflect an embedded cost of debt for the project over its economic life – or updated as part of regular price control reviews.
- The figure right shows the one-year trailing average for the iBoxx indices which, in addition to spot rates, the regulator may have needed to take into account, given the uncertainty of forward rates at the time.

Figure 5.4: Rolling 1 year average of iBoxx GBP Non-Financials indices of 10+ years maturity[1]



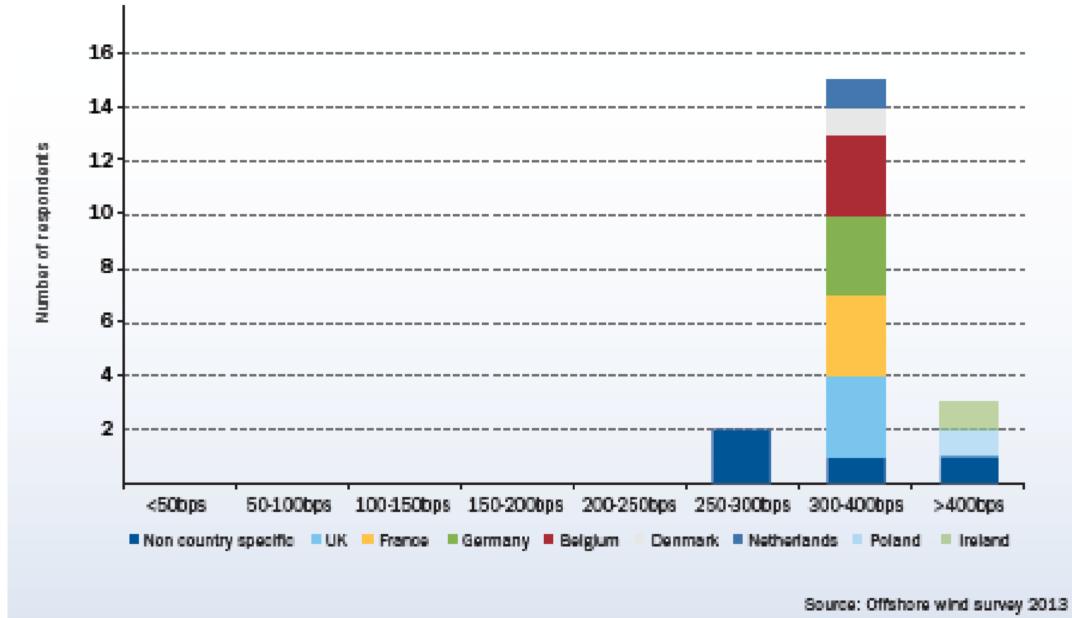
Note 1: Source: CEPA and BDO analysis of iBoxx data

The cost of debt for the merchant counterfactuals is more difficult to determine

Given the uncertainty of how the offshore transmission projects would have been treated under these regimes. We therefore rely on a range of market evidence on offshore wind debt financing costs and our relative credit rating assessment to develop assumptions for Counterfactuals 1 and 2.

- CEPA analysis for DECC in 2011 suggested a cost of debt for offshore wind projects of c.7.5% (nominal).[1]
- A recent survey by the European Wind Energy Association (EWEA) indicated a margin rate for offshore wind projects in the UK in the range 250-300 bps.
- Analysis of the Damodaran[2] financial data set in 2013 suggests a difference of 150-200bps in the cost of debt between a BBB+/A- rating and a BB rating.
- Based on our relative counterfactual credit rating assessment, this would suggest a higher cost of debt assumption should be used for the merchant counterfactuals compared to the assumptions that are used in the price controlled counterfactuals.

Figure 5.6: Offshore wind margin rates (2013) – operational phase of the project



Source: EWEA

Note 1: Assuming some construction risk remains in the project.

Note 2: Damodaran Online

Counterfactuals

Cost of debt modelling assumptions

The table below summarises the cost of debt assumptions we adopt as a starting point for modelling each counterfactual.

These are generally presented as a range to reflect the uncertainty of the rates that would have applied in reality.

Table 5.8: Proposed cost of debt assumptions for counterfactuals

* starting assumption – cost of debt is modelled based on a projected index

Cost of debt (real)	Counterfactual 1		Counterfactual 2		Counterfactual 3		Counterfactual 4		Counterfactual 5	
Range	Low	High	Low	High	Low	High	Low	High	Low	High
Cost of Debt	4.75%	5.50%	4.50%	5.50%	3.75% *		3.25%	3.75%	3.50%	4.00%

- The assumptions used for Counterfactual 1 and 2 are a judgement of the financing costs that would have been charged to the offshore transmission projects. The cost of debt assumptions for Counterfactual 1 – combined with assumptions on gearing and cost of equity – arrive at a WACC consistent with cost of figures quoted for offshore wind under the RO. The assumptions used for Counterfactual 2 reflect conclusions from our relative credit rating assessment.
- For Counterfactual 3 we assume that the allowed cost of debt assumption in the WACC would shadow the onshore cost of debt allowance under TPR4 and RIIO-T1 based on a simple 10-year trailing average index. The assumptions that are applied to project the index over the full licence term are outlined in Annex B.
- Counterfactuals 4 and 5 reflect a judgement of what *might* have been allowed as an embedded cost of debt for the full asset life of the TR1 projects based on spot rates / recent historic spreads at the time. However, given the uncertainty of approach for these counterfactuals we subject the assumptions to sensitivity analysis in Section 6.

Developing cost of equity assumptions

We apply a CAPM based modelling approach:

- Adopting a CAPM based building block approach, we consider the risk free rate (RfR), equity risk premium (ERP) and equity beta. As the RfR and ERP are economy-wide parameters, there are several reference points available for these.
- We therefore focus on the equity beta, and in turn, asset beta of each counterfactual. This is due to changes in the gearing level affecting the required cost of equity.
- There is an absence of directly observable beta estimates, so we present a broad appraisal of our expected beta estimates. This methodology is based on a relative risk spectrum analysis. Our starting point for this is an asset beta of 0.4 for TPCR4.
- For the regulated price control counterfactuals, we analyse the *allowance* for the beta term rather than actuals betas. In the case of National Grid for example, the observed asset beta is approximately 0.2 compared to an allowance of 0.4 (actual depends on averaging period, rolling beta estimation period and gearing methodology).
- As a starting point for the analysis we use a 2% RfR and 5% ERP assumption. However, we also consider more recent regulatory precedent (e.g. from the RIIO price controls) and market evidence on economy-wide parameters in applying sensitivity analysis to the cost of equity (see Section 6).

Whilst we work within a CAPM framework, we develop the cost of equity assumption to reflect a broad overall assessment of what could have been the expected and/or allowed equity rate of return requirement for these operational projects.

Counterfactuals

Cost of equity relative risk assessment

Key

↓ Lower risk than OFTO regime

Table 5.9: Counterfactual equity relative risk assessment

Regulatory Factors	OFTO regime	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4	Counterfactual 5
Risks during the operational phase relative to the OFTO regime						
Operational risk	Yes	⇔	⇔	⇔	⇔ or * ↓	⇔ or * ↓
Availability risk	Yes	⇔	⇔	⇔	⇔	⇔
Payment/counterparty risk	Yes	na	↑	⇔	⇔	⇔
Inflation risk	None	↑	⇔ or [1] ↑	⇔	⇔	⇔
Demand risk	None	↑	⇔ or[1] ↑	⇔	⇔	⇔
Stranding risk	None	↑	↑	⇔	⇔	⇔
Financing risk	Yes	⇔	⇔	⇔	⇔	⇔
Tax risk	Yes	⇔	⇔	⇔	⇔	⇔
Future connection / wider network programme delivery risks	No	⇔	⇔	↑	⇔	↑
Overall assessment of asset beta		↑	↑	↑	⇔	↑
CEPA asset beta assumption		1.0	0.6 – 0.7	0.4	0.3 – 0.4	0.4 – 0.5

* In theory operational risk could be reduced if diversified across a number of projects.

1: Depends on the terms of the sale and lease back contract, including treatment of use of system and inflation.

The asset beta assumptions presented above developed above are re-levered at the assumed gearing level assumptions for each of the counterfactuals. This provides an equity beta assumption for each counterfactual.

Counterfactuals

Cost of capital assumption ranges under merchant counterfactuals

- The table below summarises the cost of capital assumptions used in the cost benefit analysis for the merchant led counterfactuals (Counterfactual 1 and Counterfactual 2).

Table 5.10: Counterfactuals 1 and 2 - Vanilla WACC (real)

	Counterfactual 1		Counterfactual 2	
	Low	High	Low	High
Gearing	60.00%	60.00%	70.00%	80.00%
CoD	4.75%	5.50%	4.50%	5.50%
CoE	14.50%	14.50%	12.00%	19.50%
WACC	8.65%	9.10%	6.75%	8.30%

- For Counterfactual 1, our high and low estimates reflect cost of capital figures typically quoted for UK offshore wind generation operating under the Renewables Obligation.
- For Counterfactual 2, the cost of debt and equity assumptions are based on the relative risk analysis and reflect the higher payment (counterparty) risk / exposure to the performance of the wind farm compared to other (e.g. regulated price control) counterfactuals.

We subject these assumptions to sensitivity analysis through the CBA modelling in Section 6.

Cost of capital assumption ranges under price controlled counterfactuals

- The table below summarises the cost of capital assumptions used in the cost benefit analysis for the regulated price control counterfactuals (Counterfactuals 1, 2 and 3).

Table 5.11: Counterfactuals 3,4 and 5 - Vanilla WACC (real)

	Counterfactual 3		Counterfactual 4		Counterfactual 5	
	Low	High	Low	High	Low	High
Gearing	60.00%	60.00%	50.00%	60.00%	50.00%	60.00%
CoD	Indexation – see Annex B		3.25%	3.75%	3.75%	4.25%
CoE	7.00%	7.00%	5.00%	7.00%	6.00%	8.25%
WACC	5.05% - starting assumption		4.13%	5.05%	4.88%	5.85%

- These assumptions are the allowed cost of capital used to determine allowed revenues. This is based on what Ofgem could reasonably have expected to have achieved at the time and subsequently over the life of the assets.
- It is not the actual cost of capital being faced, but rather what could have been granted at the time (without the benefit of hindsight) and used to set regulated prices.
- A difference between the allowed and actual cost of capital would involve a transfer of value from those parties that pay for the offshore transmission services to the investors in the transmission provider.

We subject these assumptions to sensitivity analysis through the CBA modelling in Section 6.

Counterfactual operating costs (1) … methodology

We use two methods to develop counterfactual operating cost assumptions:

- We can never know for sure what the comparator operational costs would have been under our counterfactuals, but our counterfactuals do assume different roles for: regulated price reviews, licence application processes and a generation developer role in operational cost contracting / offshore transmission delivery.
- This is reflected in the two methodologies that we have used to develop assumptions for operating costs which can then be applied to each of our counterfactuals.

Method One	Our first method compares preferred bidder operating costs across the nine TR1 projects (equivalent to the base case) to: 1) average ITT stage submissions on operating costs across all the short-listed TR1 bidders; and 2) existing transmission providers ITT submissions on operating costs for TR1. This first approach reflects outcomes under a competitive process.
Method Two	Our second methodology uses a benchmark from a National Grid / Crown Estate study[1]. In this case, O&M costs are assumed to be a percentage of the installed capital costs of the TR1 projects. As this focuses on O&M only, we also use TR1 data for non-O&M costs to develop a total counterfactual operating assumption under this second method.

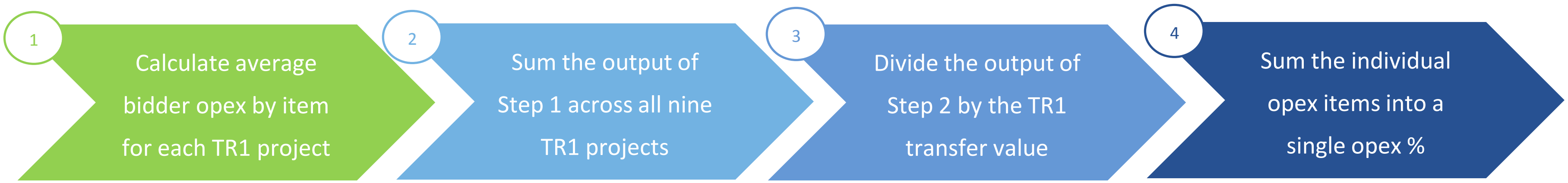
Note 1: National Grid and Crown Estate (2011): 'Offshore Transmission Network Feasibility Study'

Counterfactual operating costs (2) … Developing assumptions with Method 1

Comparisons of TR1 bid data:

- We develop a comparison of the preferred bidder to average bidder opex as follows:

Figure 5.2: TR1 average bid calculations



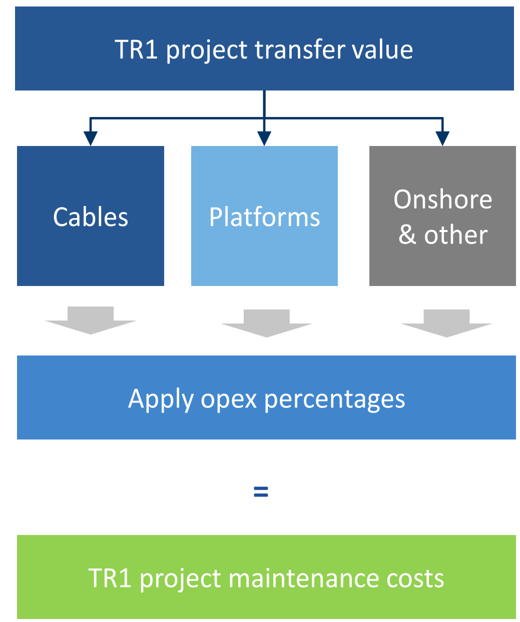
- We adopt a similar approach for comparing existing transmission services provider's TR1 tendered operating costs to the preferred bidder operating costs. This information is used to develop assumptions for Counterfactuals 3 and 4.
- This, however, requires methodological adjustments as this provider only bid on two projects in TR1, and reached the final stage on just one project.
- To develop operating cost assumptions which can be applied under counterfactuals for all nine TR1 projects, we calculate a ratio of the existing transmission service provider bid for individual cost items as compared to the preferred bidder (on a TRS basis) at that stage of the tender process. We then take the average of this ratio across the two TR1 projects to develop a counterfactual benchmark.

Counterfactual operating costs (3) … Developing assumptions with Method 2

O&M based on asset break down approach:

- To apply this methodology we breakdown the installed capital costs of the TR1 projects according to:
  - offshore cables;
  - offshore platform; and
  - onshore and other.
- Having broken down the asset base into these categories, the operation and maintenance cost drivers (expressed as a % of a each cost category) are then applied to calculate a counterfactual O&M cost.
- We then need to translate this figure into an overall operating cost figure so we add other operating cost items (including insurance, transaction, SPV and management costs) based on the same comparators as under Method 1.

Figure 5.3: Counterfactual O&M costs



Counterfactual operating costs (4) … Comparing counterfactuals

Key assumptions:

- Our assumptions on counterfactual operating costs include operation and maintenance (O&M), insurance costs, decommissioning costs, Special Purpose Vehicle (SPV) and/or management costs.
- Three of five counterfactuals would have a regulated price control applied to them (Counterfactuals 3 - 5). As such, their operating cost allowances would have been revised for each price control review period.
- The modelling of operating costs assumes a 20-year asset life (as with OFTO licences) and four five-year price controls (including the starting price control), with a step change in operating costs at the start of the price control.
- Closing operating costs for these three counterfactuals are, therefore, assumed to be lower in the later years of the licence period to reflect the impact of a learning process through price control reviews.
- We also develop a range of scenarios for operating costs for each counterfactual. Our assumptions are driven by the role of competition, price reviews and new service providers in each counterfactual.

Below we describe how we have developed scenarios on operating costs for the counterfactuals.

Counterfactual operating costs (5) … Developing scenarios

Our assumptions are driven by the role of competition, price reviews and new service providers in each counterfactual:

- **For the merchant counterfactuals,** we assume operating costs which are broadly consistent with preferred bidders operating costs as revealed through TR1. We would have expected the transmission service provider (e.g. in Counterfactual 2) to have taken advantage of generator provided O&M packages, where available, and the generation developer to have developed and procured a relatively low operating cost package. Therefore, as a low case, we adopt preferred bidder bid costs from TR1 and a high case that uses a slightly more conservative assumption of operating costs.
- **For the price controlled counterfactuals,** we use operating costs of existing transmission operators and other unsuccessful bidders (compared to OFTO preferred bidders) as revealed through the TR1 bids to develop our assumptions and also assume price reviews drive down costs over the licence term. There may be reasons as to why such amounts were bid[1], but it is difficult to suggest alternative assumptions given the revealed prices reflect the specific context of the TR1 projects.
- **Counterfactual 5** has a lower starting operating cost assumption than Counterfactuals 3 and 4 to reflect that all, or potentially aspects of, the operational cost base of the zonal licensee could have been subject to competitive pressure through the licence application process. Effectively the zonal operator would still have been subject to price reviews, but would have needed to commit to certain costs upfront through the licence application process.

Note 1: For example, individual operators may have made particular operational and maintenance decisions as part of decisions on the more general commercial structure of their bids, including to address any perceived legal restrictions on particular operating solutions.

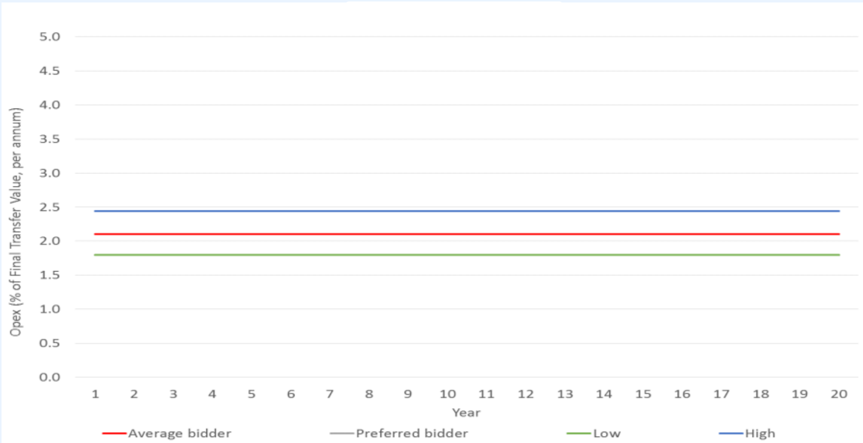
Counterfactual operating costs (6) … Developing scenarios

Operating costs assumptions for Counterfactuals 3, 4 and 5 reflect regulatory asymmetry of information and the challenges of regulating transmission services through negotiation, rather than a contestable process:

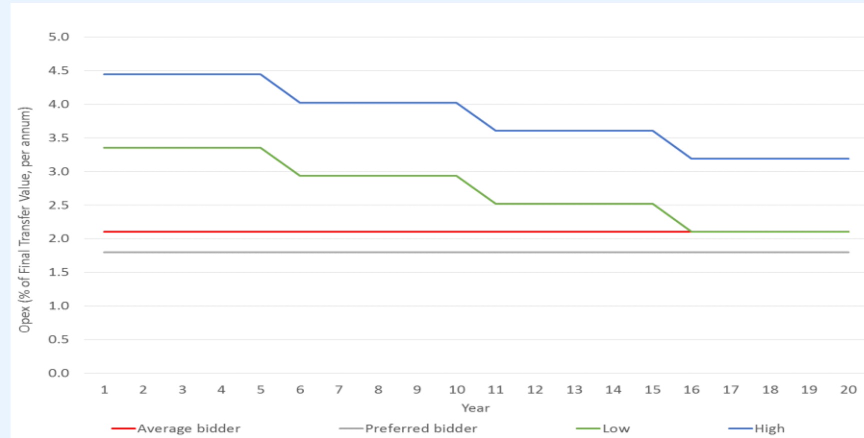
- Networks in GB and their associated price control arrangements have delivered for network users, and continue to deliver under new regulatory frameworks such as RIIO (Revenue = Incentives + Innovation + Outputs). These regulated price control frameworks have been reinforced by the competitive disciplines of financial markets and regulatory regimes have been designed to mimic the pressures of a competitive market pending the arrival of effective competition.
- However, price reviews, as negotiation processes, still face the challenge of providing appropriate incentives for timely, efficient and adequate delivery by network providers, by developing a procedure that commands credibility, overcomes regulatory asymmetry of information and efficiently applies available benchmarking data.
- A contestable process for offshore transmission (as under the OFTO regime) in contrast helps to overcome a number of these challenges through revealed pricing. In contrast, regulated, price control review based, counterfactuals rely on benchmarking and regulatory negotiation. Therefore, we assume operating costs under counterfactuals 3 and 4 are higher than the preferred bidders in the TR1 process, with the basis for the counterfactual assumptions described above.
- **This is not to say that current price control arrangements for onshore energy networks are not delivering effectively for consumers.** Rather that a contestable process, given the unique circumstances of radial offshore generation connections, was possible for TR1 projects and this helped to establish efficient operating costs compared to having to apply the price review and benchmarking processes to the specific offshore generation connection projects.

Counterfactuals

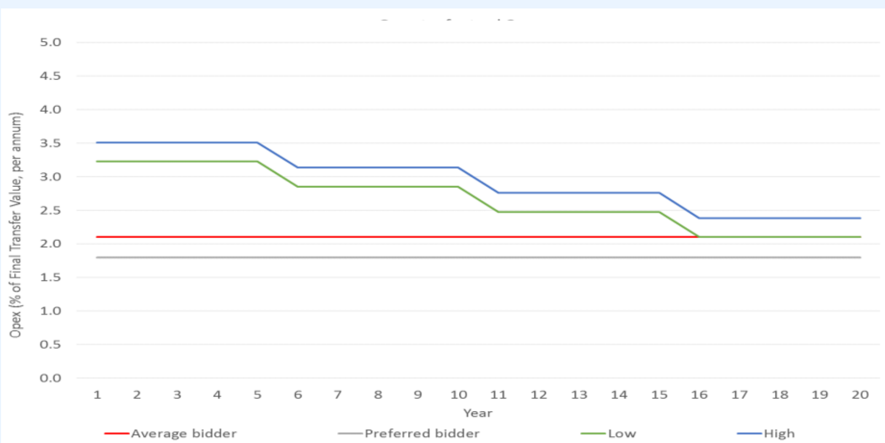
Counterfactual 1 and 2 – operating cost assumptions



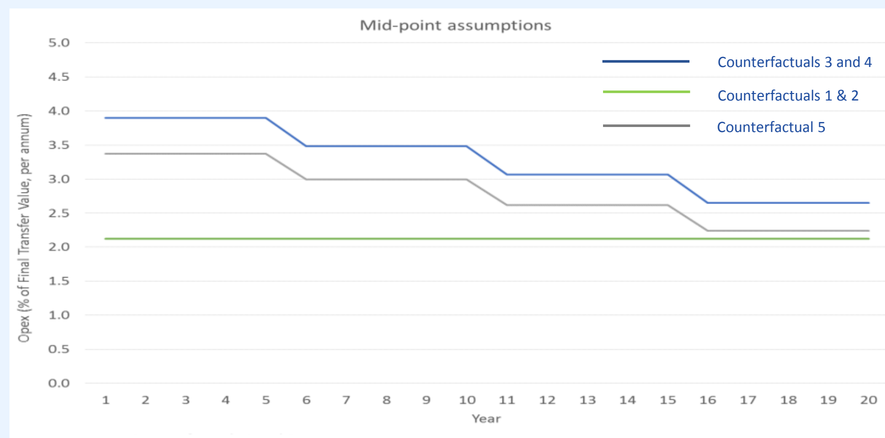
Counterfactuals 3 and 4 – operating cost assumptions



Counterfactual 5 – operating cost assumptions



Mid-points of counterfactuals – operating cost assumptions



Counterfactual bid cost assumptions

Counterfactual bid costs depend upon whether a competitive procurement / licensing application process is used:

- As described in Section 3, there have been various transaction related costs linked to the tender process which was applied to TR1 under the Transitional OFTO regime.
- For our counterfactuals, we assume there would have been no bid costs associated with the tender process, except for Counterfactual 5 where a more contestable process could potentially have been held.
- Under the counterfactuals where bid costs are not included, this results in a net cost (rather than benefit) from the contestable TR1 appointment process.
- This is, however, a relatively conservative assumption as other counterfactuals may still have incurred some form of bid related costs associated with developing the regulated and commercial arrangements for the transmission operator.
- For example, under counterfactuals 3 and 4 there would have been some (albeit relatively small) costs associated with Ofgem running price review processes for offshore transmission assets.

These relative assumptions on bid costs are reflected in our cost benefit analysis.

6 COST SAVING AND OTHER COST BENEFIT CONSIDERATIONS

Introduction

In this section we present:

- The costing analysis that compares our assumption based costing of each of the counterfactuals to the outcomes observed from the contestable TR1 process.
- From this we are able to estimate the cost savings that have been realised from applying the Transitional OFTO regime to the offshore transmission assets, when compared to the counterfactuals. At this stage we do not consider the distribution of those savings, which is the focus of Section 7.
- From a more qualitative perspective, we also consider the financial deliverability of the counterfactuals compared to the outcomes of the TR1 process and other policy decisions taken for the OFTO regime, including indexation and refinancing mechanisms.

We show that:

One	Our estimated cost savings are higher than Ofgem's previous estimates when compared to both regulated price control and merchant counterfactuals.
Two	The sources of savings differ depending on the counterfactuals chosen. In some cases the source of the savings is financing costs, in other cases the savings relate to operating costs.
Three	The cost savings change depending on the counterfactual assumptions but our key conclusions still hold even if we vary from our central modelling assumptions.
Four	We find that there may also have been financial deliverability constraints on a number of counterfactuals which may have impacted on timely delivery and possibly the cost of finance.

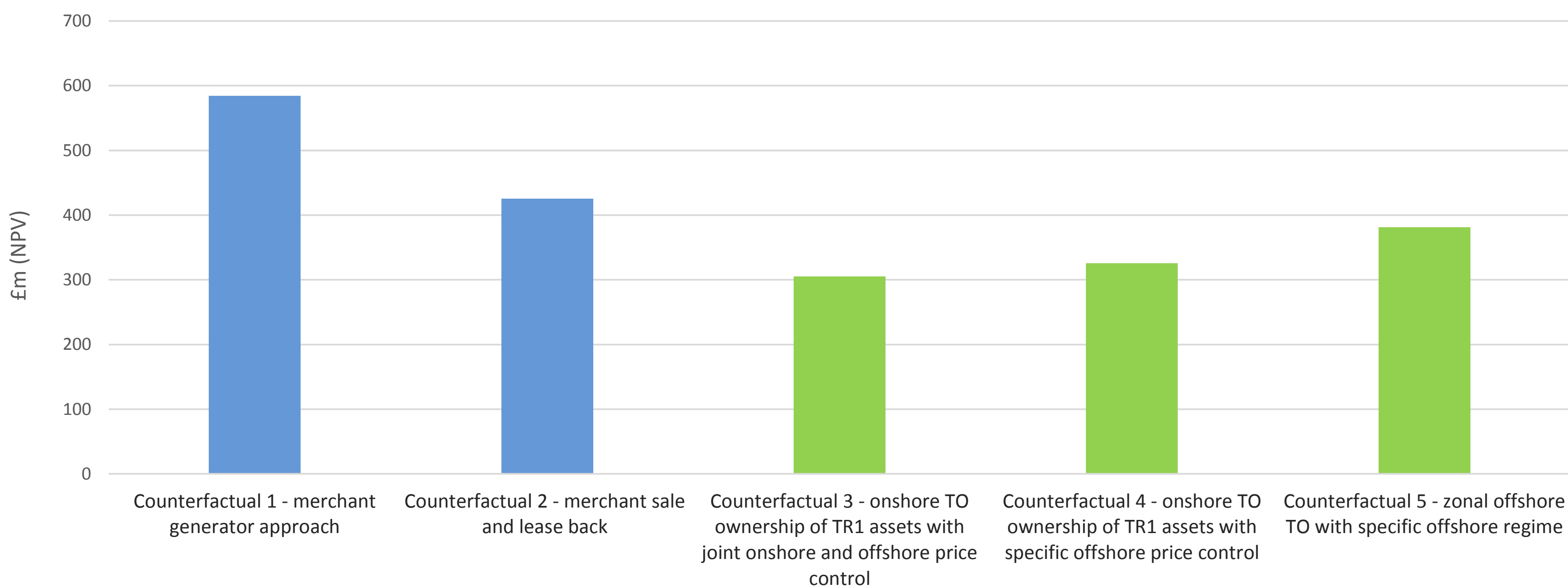
COST SAVING ANALYSIS

What are the key findings?

Our estimated cost savings are higher than Ofgem's previous estimates

Based on our central counterfactual assumptions[1], the avoided costs (including tax savings) derived from the TR1 process compared to a range of merchant and regulated counterfactuals, are all greater in NPV terms than the £300m originally estimated by Ofgem.

Figure 6.1: Cost savings of the OFTO regime compared to counterfactuals (£m NPV)



This is our assessment of the cost savings achieved from the contestable OFTO process in TR1.

Note 1: Derived by taking the mid-point of the range for the cost of capital and operating cost assumptions which are developed for each of the counterfactuals. Counterfactual 3 has only a central assumption.

What is the source of the cost savings?

The source of the savings differ depending on which counterfactual is chosen

Table 6.1: Estimated net benefits of the OFTO regime compared to counterfactuals (£m NPV)

Benefit driver	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4	Counterfactual 5
	"licensed merchant generator approach"	"merchant sale and lease back arrangement"	"onshore TO led with the rollout of TPCR4 regime"	"onshore TO led with specific offshore regime"	"zonal offshore TO with specific offshore regime"
Estimated direct benefits (£m NPV) - cost savings under the OFTO regime relative to the counterfactual					
1 Financing costs	380	266	8	17	84
2 Operating costs	49	49	232	232	172
3 Tax	191	146	112	112	126
4 Bid costs	-35	-35	-35	-35	-
TOTAL BENEFIT (INC TAX)	585	426	306	326	381
TOTAL BENEFIT (EXC TAX)	**394**	**279**	**205**	**214**	**256**

Note: analysis is in Net Present Value (NPV) terms.

The Transitional OFTO regime exhibits cost benefits over all the counterfactuals. We have sought to identify the sources of the cost savings through comparing the component costs, to the outcomes under the competitive process for TR1.

Interpreting the results

Compared to the merchant counterfactuals, we estimate the OFTO regime delivered financing cost savings as a result of reducing payment and other asset stranding related risks

In the case of the merchant generation counterfactuals, Table 6.1 shows that the cost benefits are driven by *lower financing costs*. This arises, in our view, from an optimal risk allocation, specifically as regards:

- lower payment/counterparty risks under the OFTO approach, as a result of NGET (and ultimately consumers) guaranteeing payments;
- no exposure of the appointed OFTO to the performance of the associated offshore wind farm; and
- the degree of consumer underpinning of regulated investment which exists, as compared to the merchant counterfactuals.

The OFTO regime involves an allocation of relatively low probability but high impact stranding risks to consumers compared to the merchant counterfactuals, as well as allowing a combination of contestability for, with regulatory treatment of, transmission assets which form an integral part of offshore generation projects.

In short, this appears to amount to a relatively optimal approach and allocation of risk from a pricing perspective given the nature of the contestable opportunity created.

Compared to the regulated price control counterfactuals, we estimate the OFTO regime delivered lower operating costs

In the case of the regulated price controlled counterfactuals, Table 6.1 shows that the savings arise from lower operating costs associated with the likely path of these costs over time. The scale of the saving depends upon the view as to:

- the speed at which the process of price control reviews would have moved the projects to the efficiency frontier; and
- whether price reviews would have overcome challenges of regulatory asymmetry of information by setting prices through a price review negotiation, rather than contestable process of revealed pricing.

We believe that the key attributes of the implemented OFTO approach in TR1, including the contestable nature of the OFTO regime and the clear risk profile for TR1's post construction assets, are also the source of the cost savings which we estimate when comparing to the regulated price controlled counterfactuals:

- The OFTO approach helped define the true risk profile of the TR1 assets. In contrast, for Counterfactual 3, we believe it would have been more difficult to isolate the risk profile of the OFTO from the rest of the transmission 'project portfolio' resulting in higher allowed financing costs.
- If compared to a scenario where a relatively low cost of capital is assumed in the counterfactual (Counterfactual 4), the low risk profile of the OFTO regime and the contestable opportunity created, still appears to have allowed financing costs under the OFTO approach roughly equivalent to that allowed for low risk RAB-based financing.

The analysis would suggest that the nature of the contestable opportunity created for TR1 projects, enabled competition to be introduced into the sector, without increasing financing costs compared to rates of return typically allowed for standard RAB-based price controls.

SENSITIVITY ANALYSIS

Sensitivity analysis assumptions

There is uncertainty regarding the cost and policy parameters that might have applied under all of the counterfactuals

Therefore, we subject the cost savings analysis to sensitivity analysis.

The sensitivity analysis focuses on uncertainty of what operating and financing cost parameters would have applied for each of the counterfactuals, as reflected in the counterfactual ranges developed for these parameters, but also issues such as regulatory precedent.

The recent RIIO-ED1 fast-track decision, for example, adopted a lower market cost of equity than is adopted in the counterfactuals. We analyse what would have been the impact if similar assumptions had been accommodated within the price controls for TR1 projects.

The table below summarises the sensitivity analysis undertaken of the cost savings analysis, with the results and our interpretation of those results then presented in the pages which follow.

Table 6.2: Modelled sensitivity analysis

Counterfactual ranges	Market assumptions
We model the low and the high cost of capital and operating cost assumptions consistently across each of the counterfactuals. This compares to the modelling results presented above which take the mid-point of these ranges as the modelling assumption.	For the RIIO-ED1 fast-track decision, Ofgem suggests a range of factors point towards a lower cost of equity for DNOs than indicated in previous consultations and network price control decisions, including current financial market conditions. To account for this, as a variant for our counterfactuals, we model a 6.5 per cent equity market return assumption within the CAPM using our equity beta assumptions.

Sensitivity analysis results

The illustrations below compare total cost savings applying the high and low values from the counterfactual assumption ranges

Figure 6.2: Cost savings under low counterfactual assumptions

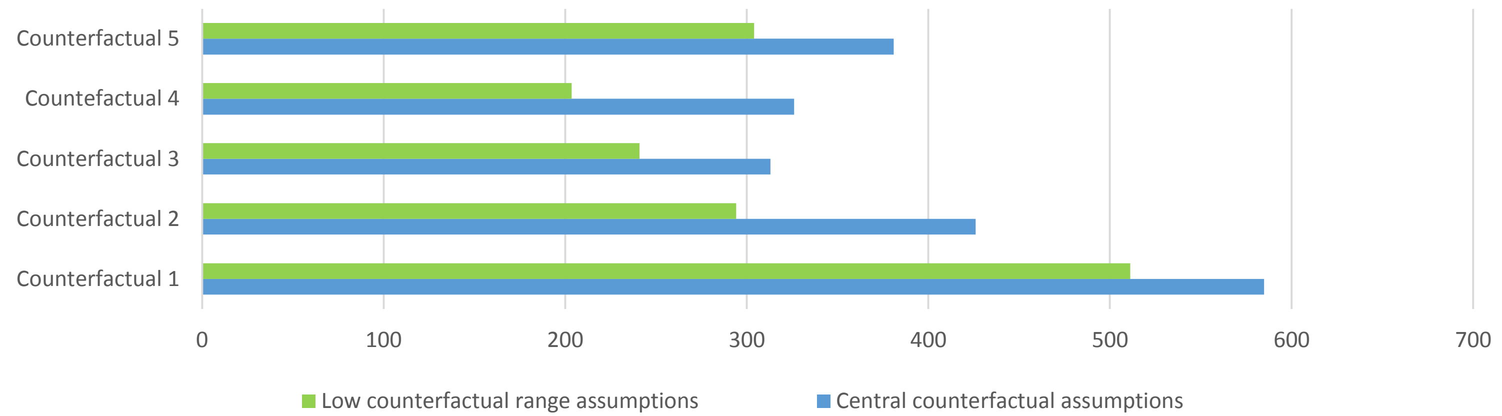
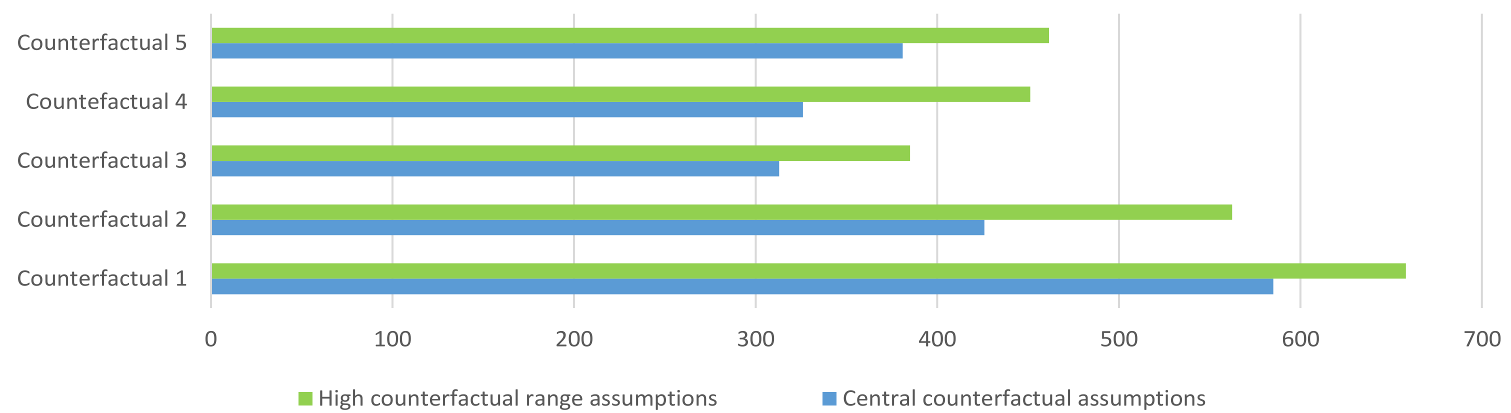


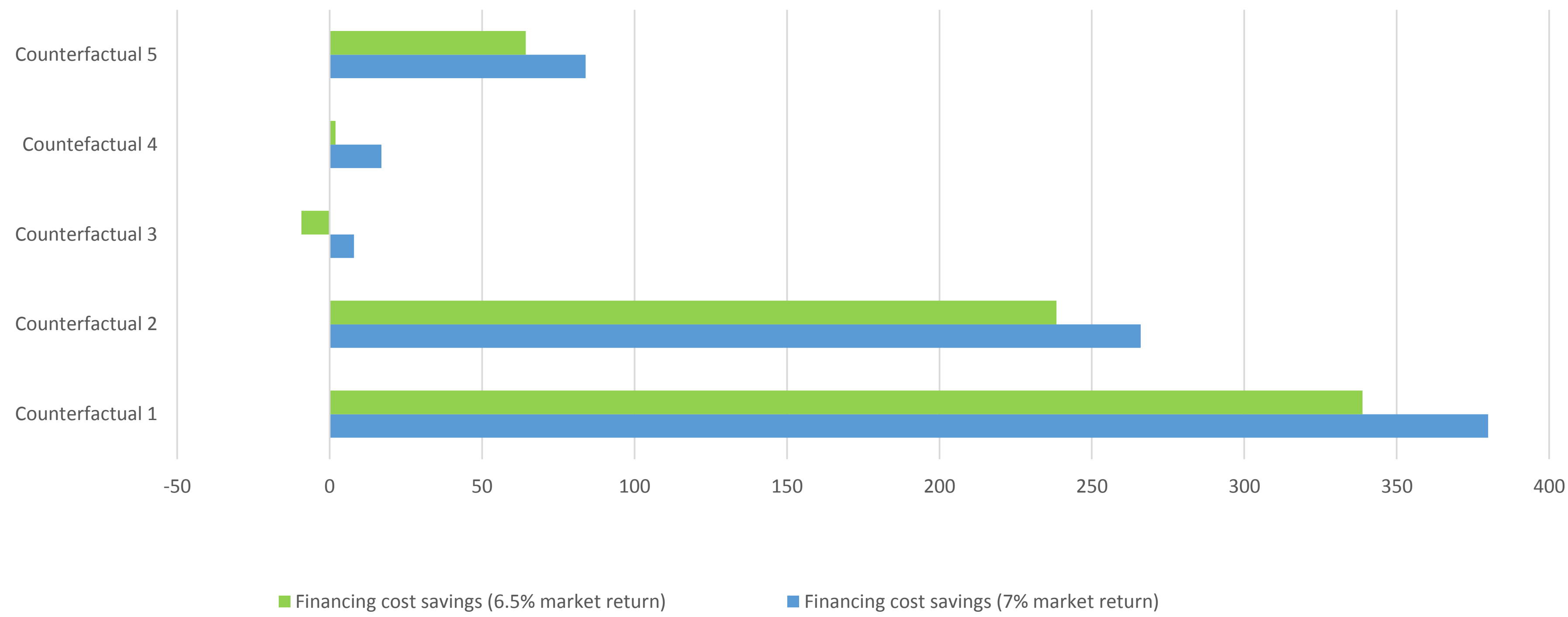
Figure 6.3: Cost savings under high counterfactual assumptions



Sensitivity analysis results

The illustrations below compare financing cost savings applying a 7% (central) and 6.5% market equity rate of return in the counterfactuals

Figure 6.4: Financing cost savings under alternative market equity rate of return assumptions



Interpreting the sensitivity analysis

The sensitivity analysis shows that the cost savings change depending on the counterfactual assumptions adopted, but our general conclusions still hold

As regards the merchant counterfactuals:

- Where lower financing cost assumptions are adopted in the counterfactuals – both on a relative risk basis and equity market return – compared to our central assumptions, the OFTO regime is still shown to deliver financing cost savings.
- The conclusions on merchant counterfactual operating costs are generally invariant to where the assumption is drawn from within the counterfactual range, because of the assumption that the generation developer would have developed and procured a relatively low operating cost package, which is reflected in the relatively low and narrow range for operating costs.

As regards the price controlled counterfactuals:

- Even if lower operating cost assumptions are adopted than the central CBA assumptions, the analysis shows the OFTO regime as delivering operating cost savings. The scale of the cost benefit is lower, but our conclusions on sources of cost savings under the OFTO regime still hold.
- Sensitivity analysis of counterfactual financing costs shows that, under certain assumptions, it is possible price regulated counterfactuals could have achieved lower financing costs than the OFTO regime. However, the scale of the difference in modelled financing costs would suggest the contestable opportunity created was able to introduce competition to the sector without *materially* increasing financing costs.
- We note that the cost of capital needed to produce these sensitivity results on financing costs would have been unprecedentedly low at the time of the TR1 process. These assumptions also don't take account of wider financial deliverability considerations in the context of offshore networks and the form of overall financial package that may have been needed for the sector (see discussion below).

Other Transitional OFTO projects

To test our TR1 findings we also compared the same counterfactuals to the OFTO tender for London Array …

Ofgem has started or completed other tenders under the Transitional OFTO regime since running TR1:

- London Array is the largest project under the Transitional regime and is the first tender in Tender Round 2 (TR2) to reach financial close. The licensed OFTO for the project is Blue Transmission.
- Although the London Array tender took place in a different context to TR1, it provides a point for comparison to our findings on the initial Transitional tender round.
- Applying the same cost benefit analysis methodology as we applied for the TR1 projects, including the same counterfactual assumptions, we estimate that the avoided costs (as a percentage of asset value) for London Array could be 20-30% higher than for the TR1 projects, depending on the counterfactual and assumptions adopted.
- This illustrates the possible scale of learning benefits that have been achieved from TR1 particularly for the larger pipeline projects associated with future offshore wind farms in GB, although the estimated scale of the cost benefits specifically for London Array relies on the same counterfactual assumptions being used as for the TR1 analysis.

… this sensitivity analysis supports our TR1 findings that the OFTO approach has resulted in cost savings when compared to a range of plausible counterfactuals.

OTHER COST BENEFIT CONSIDERATIONS

There were transaction costs associated with TR1 but there is the opportunity to reduce them in the future

- While there may have been cost savings from the TR1 process, one of the trade-offs has been the high bid/transaction costs as a percentage of asset value (linked to the tender process) compared to other counterfactuals.
- Partly this reflects the application of a new regime to TR1 (which departed significantly from standard price control review approaches) but also the small size of the TR1 projects.
- As the OFTO regime is rolled out for future tender rounds (Tender Round 3 and beyond) we would expect the transaction cost-to-benefit ratio to improve, as the tender process becomes even more familiar and the sizes of transmission projects increase.

Table 6.3: Bid cost to benefit ratios for counterfactuals 1 - 4[1]

£m NPV	Counterfactual 1	Counterfactual 2	Counterfactual 3	Counterfactual 4
Bid costs under TR1	-35	-35	-35	-35
Cost savings (incl tax)	585	426	306	326
Cost savings (excl tax)	394	279	205	214
Benefit ratio (incl tax)	6%	8%	11%	11%
Benefit ratio (excl tax)	9%	13%	17%	16%

Note 1: Counterfactual 5 is excluded from the analysis given the additional bid / transaction related costs that we include in this counterfactual.

The OFTO regime for TR1 has index-linked payments to RPI inflation …

This has meant that inflation risk is allocated to the parties which ultimately pay for the offshore transmission services (consumers and generators) rather than OFTOs.

- Whilst a similar allocation of inflation risk applies under other energy network price controls (where revenues are also linked to RPI), given the context of the OFTO regime, was an optimal allocation of inflation risk achieved for TR1?
- This question cannot be answered definitively. Given the cost base of the TR1 projects and the capacity for bidders to adopt contracting innovations, it seems at least possible that inflation risk could have been allocated differently (at lower expected cost to consumers and generators) without significantly increasing investor risk and, therefore, financing costs.
- At the same time, TR1 was the first set of tenders for a new and innovative offshore regulatory regime. Ofgem and the Government needed to take a judgement of what was needed (including protection against inflation – a feature typically observed in utility sector regimes) to attract investors into a new market.
- Without the high levels of interest in TR1 to support a competitive tender process, there may not have been the same extent of direct and indirect benefits from the tender round.
- There are also wider industry considerations to take into account when considering the allocation of inflation risk, linked to the subsidy regime for offshore wind in Great Britain. Subsidy levels under the Renewables Obligation (RO) are also indexed to RPI, with offshore wind generators, as detailed in Section 7, responsible for funding a high proportion of transmission costs associated with the TR1 projects. The adopted indexation approach for OFTOs, therefore, matches the revenue profile for generators under the RO, which may be seen as beneficial by the owners of the offshore wind farms associated with TR1.

Approach to inflation indexation

… and this has had both practical and cost implications for the way OFTOs have structured their bids to manage their inflation exposure

Indexing 100 per cent of the TRS will result in the OFTOs carrying an exposure to inflation as financing costs will not fluctuate with inflation (unless the OFTO has arranged index-linked financing). There is a result a mismatch between the OFTO's revenue (which is fully index-linked) and the overall inflation of its cost base.

A number of bidders in TR1 sought to protect themselves against these effects by entering into RPI swaps. The issue is that in the absence of full indexation, this is unlikely to be a hedging transaction (with associated costs) that they would need, or indeed would want to enter into, given the large fixed cost financing component (in the absence of index-linked financing) of an OFTO cost base. While the rationale for the policy adopted in TR1 on revenue indexation is clear, it has meant:

- additional costs for OFTO projects to bear given the RPI swap providers charge a credit spread for providing such instruments;
- RPI swaps create a contingent liability, with the potential for significant breakage costs in the event the RPI swap needs to be cancelled; and
- *potentially* generous arrangements for OFTOs "*since their financing costs, which account for around eighty per cent of their average annual costs, can be fixed when the licence is awarded and need not be exposed to inflation.*"[1]

It is possible that alternative approaches to that applied in TR1, such as fixing only a percentage or permitting a biddable percentage of the TRS to be indexed, would involve much closer alignment between inflating costs in the underlying OFTO cost base and the indexation of allowed revenues. This will in general reduce the need to carry revenue surpluses or deficits over time, thereby reducing financing costs, and the need to engage in costly inflation hedging strategies.

Note 1: NAO (2011): 'Offshore electricity transmission: a new model for delivering infrastructure'

Approach to inflation indexation

There are opportunities to improve inflation risk allocation in the future

We consider that the initial Transitional OFTO regime (as demonstrated through the quantified cost savings) has delivered a relatively efficient risk allocation:

- Whilst indexation is an area where alternatives (and potentially improvements) could have been considered (given precedents in other areas such as PFI), at the time it was necessary to balance consumer interests with the challenges of attracting new investment in a different type of asset in difficult circumstances.
- There are no doubt opportunities for improving the regime going forward, but discussions of these would be academic if finance had not been attracted in the first place.
- We also note that the approach adopted for TR1 (an asset-based regime with tender rounds) has meant Ofgem has been able to establish OFTOs as an asset class with the flexibility to develop the regime - something that may not have been as feasible under other price regulated counterfactuals, illustrating the learning benefits and "option value" of the Transitional OFTO regime.
- For example, under future tenders, based on a similar "generator build" model as TR1, we understand bidders will be able bid the proportion of their revenue to be indexed to inflation[1], providing the opportunity for future innovation in inflation risk allocation.
- Bidders may still wish to adopt full indexation where it can deliver value, but there will be the flexibility to adopt different assumptions given the asset-specific nature of the contestable opportunity.

Note 1: See Ofgem (2013): 'Consultation on the generic OFTO licence for Tender Round 3'

Refinancing gain share mechanisms were not included in TR1 licences …

They have, however, been included in recent PFI contracts:

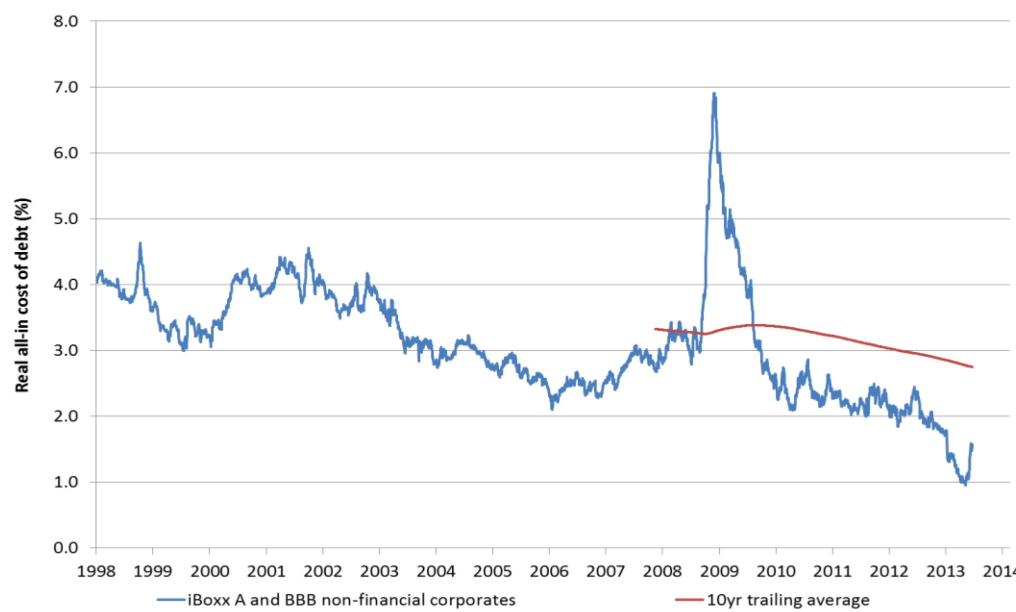
- As discussed in Section 2, the tender process to appoint OFTOs and the availability based performance incentive, have drawn comparisons with PFI as well as onshore regulated gas and electricity networks.
- A regime element introduced into more recent PFI contracts, but not adopted for OFTO licences in TR1, has been refinancing gain share mechanisms.
- While best practice in PFI has increasingly been to adopt these types of gain share mechanism, we note that for TR1, the OFTOs have adopted operational offshore transmission assets.
- As a consequence, it would not have been unreasonable to assume refinancing gains to be more limited compared to PFI where refinancing arises from changes in risk profile as projects move from construction to operation, which facilitates opportunities to access lower cost of financing.

However, what could not have been foreseen at the time that the TR1 tender process was undertaken, was the impact that changes in the "supply-side" of capital markets would have had on the cost of borrowing. As Figure 6.5 (overleaf) shows, the cost of corporate debt has fallen in recent years, linked in no small part to the Bank of England's quantitative easing programme.

… but will be included in OFTO licences for future tender rounds

- No major OFTO refinancings have yet taken place, with credit markets remaining the major source of funding of projects completed to date.
- Given the observed fall in capital market rates, it is at least possible that in future refinancing gains may be possible for OFTOs through debt securitisation providing access to the capital markets.
- As there are not refinancing gain share mechanisms in the TR1 licences, any benefits that can be derived from this process would accrue to investors, rather than the users of the transmission assets.
- In the contrast, in the context of the counterfactuals, it is possible that refinancing gains may have been captured through the design of the regulatory regime.[1]

Figure 6.5: Real all-cost of capital market debt



Source: CEPA and BDO analysis of iBoxx data

As with indexation, however, this may be an aspect of the regime which can be developed for future tendering rounds and we understand Ofgem plan to introduce a form of refinancing gain share into Enduring OFTO licences.

Note 1: For example, through price reviews. Whether this benefit could have been captured depends on the financing structure adopted in practice and the extent to which this was reflected in the regulatory pricing regime. See discussion in Section 5.

FINANCIAL DELIVERABILITY

Financial deliverability

When looking at the outcomes and benefits of the approach taken to TR1, questions of financial deliverability and timing, not only for TR1, but for the whole programme are also important

- In weighing up financial deliverability, the following issues need to be considered:
  - offshore transmission was a new asset class with unfamiliar technical risks for financial investors;
  - the market for financial capital in infrastructure is global and mobile;
  - to attract sufficient capital at a cost effective level, investors need to believe the proposition is deliverable in order to commit sufficient management resource to the asset class; and
  - the scale of the required investment over subsequent rounds was very significant and therefore needed to attract capital from a wide range of sources to be cost effective.
- In the context of TR1, because the proposition built upon existing strengths of onshore regulation as well as known techniques in the PPP market, in our view this was a significant part of building market confidence so that a wide pool of capital could bid for these assets. The investment that happened in a largely timely fashion was a function of creating an attractive investment proposition as well as a clear and understood process for implementation.
- A range of practical financial deliverability issues would have been present under the different counterfactuals as the programme progressed. By considering these deliverability issues, some of the wider benefits of the OFTO regime for TR1 are highlighted.

Deliverability is relevant in the context of the whole offshore transmission programme, not just TR1, as potential investors will take a view on whether the programme is deliverable before investing their time and effort.

Deliverability of the merchant sale and lease back counterfactual would have been challenging particularly if investors were exposed to merchant risks

- Counterfactual 2 (the sale and lease back arrangement between the Generator and the Lessor) could in theory have attracted very similar investors as under the Transitional OFTO regime.
- For example, as operational infrastructure assets, the TR1 projects might have been attractive to commercial bank lending and project equity investors in infrastructure assets.
- But without the structured procurement programme that the OFTO regime created (that is, single bidding rounds and clear regulatory led tender processes) would the pool of investors been more limited? Almost definitely.
- As the investor in the sale and lease back arrangement would have received its revenues from the offshore wind farm, payment risk would also have been significantly higher, and either the terms of the contract may have exposed the investor to merchant (e.g. volume) risks or the financial investor would seek more protection on the wind farm risk (e.g. parental guarantees).

With exposure to the performance of the wind farm, and without a regulatory sponsored tender process, it seems likely a less open market and more limited pool of investors would have been observed under Counterfactual 2 than under the Transitional OFTO regime.

- It is also possible that the sale and lease back arrangements would not have been bankable (particularly if the investors in the transmission assets were exposed to merchant (e.g. demand risks) or would not have reached financial close to same timescales as the TR1 process, given the constraints on financing at the time and the nature of the investment opportunity.

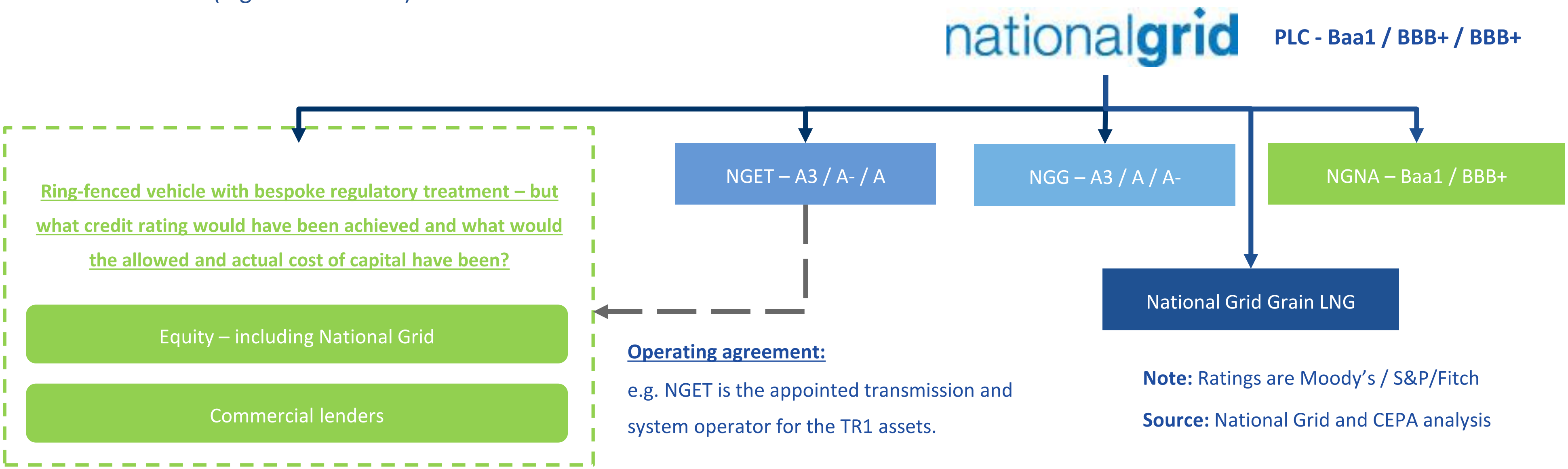
In Counterfactuals 3 and 4, balance sheet finance would most likely have been available ...

- In Counterfactual 3, debt and equity available from onshore TO (e.g. National Grid) balance sheets would depend on how the offshore programmes was treated in their overall businesses. If it was part of the wider National Grid business for example, or indeed another existing transmission provider in GB, access to finance, subject to reasonable returns, would have been forthcoming.
- The level of investment in TR1 would have been very manageable, but for the whole offshore programme, the level of business risk in the overall National Grid (or another TO) business could increase thereby potentially impacting the cost of capital for the whole business.
- Given it is relatively uncommon for UK listed companies to raise equity for ongoing investment in the business (note the reaction National Grid got to raising £3.2 billion for investment in its existing business in 2010 through a rights issue), the scale of the offshore programme means it may have created an opportunity cost as regards investment not happening in a timely fashion either in offshore assets or elsewhere in their business. National Grid would also have easily accommodated TR1 assets within its existing corporate debt programme of a range of maturities. However, given the overall scale of the programme over time, even if it was funded on a corporate basis (i.e. a range of maturities) the scale of the borrowing may have impacted pricing of their debt of the whole programme at the margin.
- Indeed over the ongoing rounds of the transmission programme, the borrowing, when aggregated with National Grids existing requirements, may have increased the overall cost of finance.
- In Counterfactual 4, how the price control would have been implemented would have created risks in the minds of the investor. Until the implementation and track record was clear, if this was owned by the holding company of National Grid (or another transmission provider), it may have been cautious if their shareholder investor base was unclear on the opportunities and risks in this new area.

Financial deliverability

… but its required scale would have had implications including for deliverability

- It is possible, therefore, that in Counterfactual 4 the offshore transmission assets in TR1 (and any future projects) could have been adopted into an independent vehicle, with the risks of the projects (given the associated regulatory regime) ring-fenced from the wider onshore TO (e.g. National Grid) business.[1]



Note: Ratings are Moody's / S&P/Fitch

Source: National Grid and CEPA analysis

- Whilst a new entity may have attracted the same type of equity as the actual route chosen, how future price controls would have been implemented and the regulatory risk perceived by the credit rating agencies and investors would have been key for deliverability and market capacity.

Note 1: Analogous financing structures are for example being considered for Thames Tideway.

Counterfactual 5 would have created additional sources of finance but it may have favoured existing transmission providers as an approach

- We consider investment in zones of transmission assets with a specific price control (subject to the detail) would have potentially been attractive to a wide range of infrastructure investors.
- The challenges is whether the zones would have created greater or more limited capacity of equity and more effective competitions. The following points are relevant:
  - Some investors did not invest in TR1 due to the equity investment being too small for the scale of their businesses. However, larger investments would have eliminated other investors.
  - A smaller number of (larger) investors may have limited the scale of the competition.
- The scale of the zones – as compared to individual projects under the OFTO regime - may have provided, or been *perceived* to have provided, an inherent advantage to existing transmission providers due to the scale of their businesses. The extent to which there would have been an advantage for existing providers would have been a function of the scale of the zones.
- Counterfactual 5 may also have been too large for the project finance markets at the time to create sufficient competition for the debt finance element of a zonal based licence competition. For example, we understand the poor availability of debt finance impacted the sale of Gatwick airport in 2009/10.

Counterfactual 5 would also have been a relatively novel and untested licensing regime in a new sector with unfamiliar technical risks for financial investors

Widening the pool of capital

The OFTO regime adopted for Tender Round 1 tapped into a wider pool of capital than the classic “balance sheet” financed regulated network/utility model typically observed onshore.

- Whilst TR1 was started but not completed in 2009, the challenging market conditions at that time need to be remembered. The bids were typically financed with infrastructure funds’ equity and project finance debt.
- The winning equity funds were typically those funds who had invested in the PPP market. This was therefore a new source of money to the transmission sector.
- It is quite possible that the underlying pension fund money that was invested in these funds might be invested in the quoted listed utility sector, but this would be a different allocation of funds and therefore not available to, say, investing in Counterfactual 3.

WHAT CAN BE DRAWN FROM THE ANALYSIS?

What can be drawn from the analysis?

Revealed prices through a contestable process are useful in understanding true costs

We believe the analysis shows that revealed prices through a contestable process are useful in understanding true costs. This was possible because the 'market offer' reflected a clear set of risks that allowed efficient, competitive pricing. It is difficult to see how this clarity and similar outcomes could have been realised through a more price regulated based regime in the context of these specific offshore assets.

Whilst there may be other instances where such a set of circumstances would allow this – that is, where there are other highly marketable transmission assets of sufficient scale and appropriate scope – there are limits as the extent to which lessons can be drawn for the onshore electricity transmission network. **The results are context-specific to TR1 and the contestable opportunity that was created reflecting the underlying technical and other characteristics of the assets in question.**

Post construction OFTO assets for TR1 are point-to-point generation connection wires outsourced to third party providers. These features, coupled with regulatory framework applied, has created a relatively low risk profile for OFTO investors. In turn, this approach has created highly contestable bidding opportunities, attracting significant operator and investor interest.

However, in reading across to what might be implied for the onshore regime, it is important to recognise that TR1 OFTOs are of a materially different scale and risk profile to a full electricity transmission network.

In addition to the cost savings that are identified, we believe there may have been wider (e.g. financial deliverability) benefits from the adopted approach for TR1 and offshore transmission delivery more generally in GB.

7 DISTRIBUTION OF COST SAVINGS

Introduction

The previous section suggests TR1 has produced overall cost benefits arising from different sources: financing costs in case of merchant, operating costs in terms of price controlled counterfactuals.

But who are the ultimately beneficiaries of these cost savings, in terms of different groups and specifically final consumers?

It may on first appearance seem that who benefits is a relatively straightforward question to answer: the wind farm uses the offshore transmission assets, consumers benefit from the generation they produce and consumers (eventually) pay the full costs of offshore transmission. Therefore, any cost savings derived from a particular approach to offshore transmission should ultimately benefit consumers.

In practice, however, the question is much more complicated due to the charging arrangements applied for offshore transmission, the economic characteristics of offshore wind and the market and subsidy support arrangements for offshore wind. As all these aspects are interlinked, it is important to ensure that the counterfactuals reflect this.

In this section we analyse:

- The interactions between the OFTO regime, the counterfactuals, electricity transmission charging and the market arrangements for offshore wind farms in the UK.
- It is by considering these interactions and the economics of offshore wind more generally that we can begin to answer who may have benefited from the cost savings that were identified in the previous section, and what some of the indirect benefits may be from the TR1 process (e.g. in terms of price discovery).

What are the economics of UK offshore wind?

We begin with a brief review of the economic characteristics of offshore wind (costs and revenues) before setting out our understanding of how TNUoS charging arrangements work in practice in GB and, given the economics of offshore wind, the implications this has for who might in practice benefit from any cost savings.

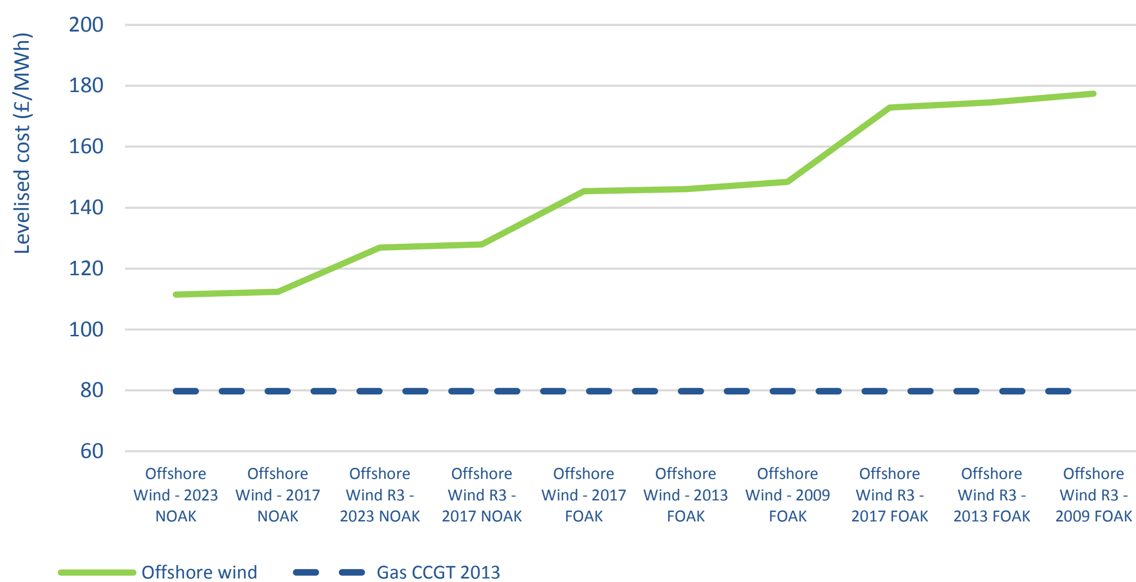
Cost of supply:

- An offshore wind generator (OWG) is an intermittent form of renewable electricity generation with high variability and low predictability (day ahead).
- Estimates of expected load factors range from 35% to 40% (taking into account existing energy generation and future efficiency increases associated with technological advances).
- Purely from a cost perspective, offshore wind generation also largely involves fixed rather than variable costs, which must be recovered across this variable production base.
- Similar to onshore wind, turbine costs will comprise the main element of the fixed capital expenditure (capex), with the grid connection (see below), vessel and foundation costs then making up the majority of the remaining capex.
- An OWG will also face a series of operating (but again, largely fixed) costs, including the costs associated with scheduled and unscheduled wind farm maintenance, management and insurance.

What are the economics of UK offshore wind?

- Figure 7.1 below shows the £/MWh levelised cost offshore wind projects as drawn from a 2010 report on UK Generation Costs prepared by Mott McDonald for DECC.
- Mott McDonald provided low, medium and high project cost estimates for offshore wind and differentiated between first of a kind (FOAK) and Nth of a Kind (NOAK) projects and projects with 2009, 2013, 2017 and 2023 start dates. These collectively help to illustrate a potential long term "supply curve" for offshore wind in the UK.
- The higher initial projected costs of Round 3 projects reflect the "*significant challenges in deploying in often deeper water further from shore*"[2] and the resulting fall in costs reflects projected industry learning with the maturity of offshore wind as a generation technology.
- The levelised costs in Figure 7.1 are also at a sector level and, therefore, there will be significant variation on a project by project basis, with some wind farm projects costlier than others.

Figure 7.1: Levelised cost estimates of Round 2 and Round 3 OWG [1]



Note 1: Assumes 10% discount rate.

Note 2: Arup (2011): 'Review of the generation costs and deployment potential for renewable electricity technologies in the UK – A Study Report for DECC', p. 50

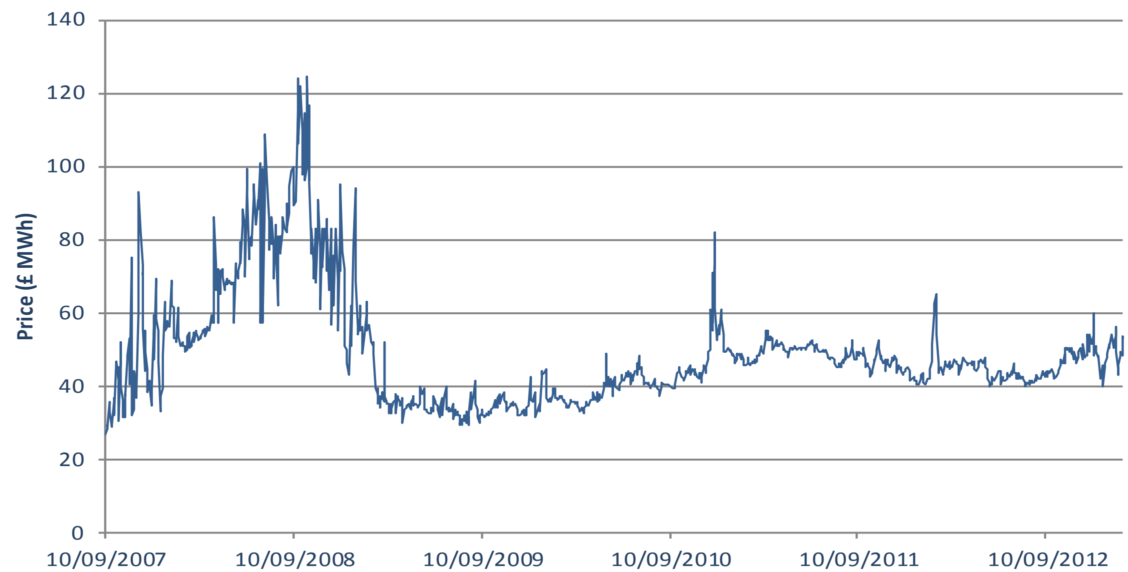
What are the economics of UK offshore wind?

- The key point to note is that offshore wind is a largely fixed cost form of variable generation with the short run marginal cost of production effectively zero.
- As it is relatively expensive technology compared to alternative forms of generation (such as coal and gas – see blue dotted line illustrated in Figure 7.1), in the medium to longer term it also requires subsidies to make investment into the sector economic. This has important implications when considering the flows of transmission costs that are funded by OWGs.

Wind farm revenues:

- Having considered the costs of offshore wind, we now turn to potential sources of revenue for offshore wind.
- OWG revenue streams are currently determined by three main elements: wholesale electricity prices, Renewable Obligation Certificates (ROCs) and the output (MWh) of the generator.
- As illustrated in Figure 7.2 (right), wholesale power prices are volatile and are generally linked to the variable costs of thermal generation plant.

Figure 7.2: GB Day-ahead generic baseload spot index [1]



Note 1: Source: Bloomberg

What are the economics of UK offshore wind?

- Even where the OWG has a Power Purchase Agreement (PPA) these are typically linked to a market price index, apply price floors in some cases or are locked in for a short period of time.
- That is to say, the OWG is a price taker in the market and, therefore, the wholesale price electricity consumers pay is independent of the (largely fixed) costs of the OWG.
- This is a crucial point. It means that if costs of offshore transmission are (to a first approximation) paid by offshore generators, then reducing these costs leads only to savings to offshore generators. Those savings could only be passed on to consumers if the offshore generators charged a lower price for their power, but since they are price takers, they cannot do so.
- The ROC (subsidy) component of the generation revenue stream is also non-controllable by the OWG as this is fixed by UK Government with the buy-out price acting as the floor price (subject to pricing discounts applied through contracting).
- While banding for offshore wind is assessed in relation to OWG costs, the level of subsidy is set at a technology sector level, as an administered price, rather than on an individual project by project basis.
- The reforms to renewable electricity support arrangements to introduce CfD Feed-in-Tariffs (FiTs) for offshore wind are expected to follow similar administered principles, at least for the period 2014/15 to 2018/19.

Distribution of cost savings

Transmission Network Use of System charges

The TNUoS charging regime impacts on who may have benefited from OFTO regime cost savings

- As described in Section 2, each OFTO recovers its allowed revenue from National Grid under arrangements described in the SO-TO Code (STC) and OFTOs' Charging Statement.
- National Grid then sets TNUoS charges to recover the total allowed revenue of all onshore and offshore transmission owners from transmission users according to the TNUoS charging methodology in the Connection and Use of System Code (CUSC).
- Generation "local" charges are used to target a large (c. 70-80%) proportion of the cost of an OFTO on the OWG who uses the transmission assets (thereby applying a "user pays" and "cost reflective" charging principle). These "local" tariffs reflect the cost of the offshore transmission assets from the generator to the main interconnected transmission system.
- However, the split of TNUoS revenue which is recovered from generators and demand is fixed in the ratio 27%/73% (Generation:Demand).

The interaction between these charging arrangements and the economics of offshore wind impact crucially on who may have benefited from the cost savings identified from the counterfactual analysis.

Distribution of cost savings

In comparisons with regulated price control counterfactuals … both offshore generators and consumers will have benefited from the cost savings resulting from the contestable OFTO approach

- For the regulated price control counterfactuals, we think it is likely the cost allocation approach applied and therefore the flow of any benefits would have been consistent with the OFTO regime – that is, under the latter, a proportionate share of the socialised cost savings would be likely to flow to consumers, although because of the structure of the transmission charging regime, generators will have received c. 70-80 per cent of the benefits through a reduction in their TNUoS charges.
- As a result, in this scenario both offshore generators and consumers will have benefited from the savings derived by the contestable OFTO approach that was adopted for TR1.
- For clarity, this means that GB consumers will have benefited directly from the estimated reduction in the socialised share of the offshore transmission cost base associated with the TR1 projects, with offshore generators also receiving lower TNUoS charges benefitting investors in those specific projects.

For comparisons with merchant counterfactuals … understanding the distribution of benefits is more complicated and depends on what is assumed regarding offshore wind subsidy levels

- The comparisons with merchant counterfactuals are more challenging as the treatment of transmission costs is different; and assessing the flow of benefits depends upon what is assumed regarding the level of administered subsidy that accounts for transmission costs in the overall offshore generation support regime.
- Under the merchant counterfactuals, offshore generators would have directly paid for the full costs of the offshore transmission connection, rather than sharing the costs with customers as in the case of the cost recovery mechanism with the price control counterfactuals.
- The key question is whether or not the support regime in the merchant counterfactuals would have compensated them for these additional costs, as the position of the consumer also needs to take into account the level of subsidy provided to the offshore generators, if the two types of regimes are to be compared.

Distribution of cost savings

In comparisons to merchant counterfactuals … there will have been savings for consumers if a higher level of subsidy support had needed to be provided to cover a higher allocation of offshore transmission costs under the merchant counterfactuals

- If the merchant counterfactuals were to involve the same subsidy contribution to transmission costs through the same level of ROC support as now, then consumers would not have benefited from the OFTO regime as all cost savings would have flowed to generators.
- However, if subsidy levels would have had to be higher in the merchant counterfactuals to reimburse generators for the higher proportion of offshore transmission costs allocated to them under the merchant approaches (and thereby holding generator returns constant between the merchant counterfactuals and the OFTO regime), consumers would be better off in the OFTO regime because of the lower level of overall subsidy required in the OFTO regime as opposed to the merchant regime (even though the cost savings on OFTOs would flow in entirety to the generators). Clearly the extent of any benefits in this trade-off would depend upon the level of ROC support allowed for offshore wind.
- In return for this reduced subsidy, however, additional (e.g. stranding related) risks have accrued to consumers under the applied OFTO regime, which must be balanced against the savings in subsidies that may have been achieved due to the OFTO regime, reflecting the trade-offs often faced in creating new contestable investment opportunities.

However, at a minimum, cost savings achieved by the OFTO regime can be considered to apply downward pressure on the subsidy levels needed in future to achieve offshore wind hurdle rates.

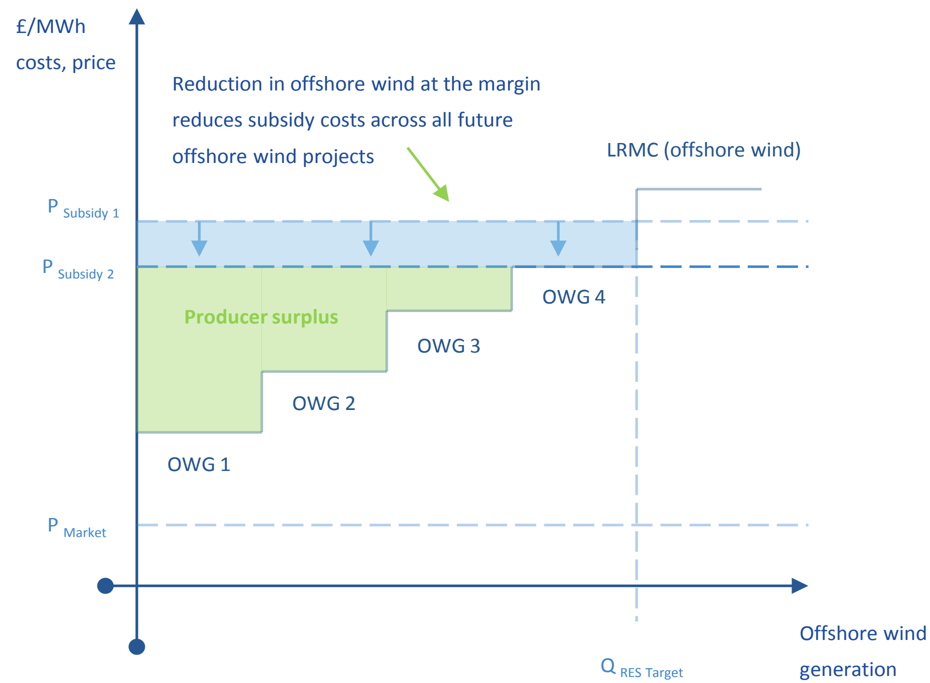
Distribution of cost savings

Implications for price discovery

Competition involving revealed pricing can be employed where it is possible to structure such approaches

- Whilst it is important to realise that the OFTO regime cannot be replicated everywhere, a lesson to be drawn is that where such opportunities do exist and any trade-offs are acceptable, such approaches should be actively considered.
- It is arguable that the contestable TR1 process has moved the industry closer to the efficiency frontier quicker than may have been possible under alternative policies and potentially this should be reflected in the future assumptions that are made for subsidy costs in the UK.
- Where subsidy prices are administered and set to reflect costs at an industry rather than individual project level, the effect of reducing offshore transmission costs, if reflected in subsidy prices, could potentially be amplified as future Round 3 wind farm project costs, for example, are reduced for the marginal project (see Figure 7.3).
- The Electricity Market Reform (EMR) delivery plan, for example, applies a CfD strike price of £155/MWh for qualifying offshore wind projects up to 2015/16 falling to £140/MWh by 2018/19 and may already reflect reduced offshore wind industry costs at the margin, as a result of the OFTO regime.

Figure 7.3: Impact on subsidies from marginal plant transmission cost reductions



8 CONCLUSIONS

The OFTO approach adopted has resulted in significant cost savings when compared to plausible counterfactuals

The OFTO approach adopted has resulted in significant cost savings when compared to plausible merchant and price control counterfactuals that might have been applied in the absence of the chosen approach; in the case of the former these arise from financing cost savings and in the case of the latter, operational costs.

In turn, these reflect the optimality of payment (counterparty) risk allocation viz-a-viz the merchant regime and the benefits of contestability in terms of revealing pricing when compared to the price control counterfactuals (although caution is warranted in terms of any comparisons with the wider onshore electricity transmission regime).

Understanding the distribution of benefits is much more complex. Whilst consumers are in a better position due to overall lower transmission costs as compared to the price control counterfactuals, which would appear to be allocated in the same way under both regimes, the outcome versus the merchant counterfactuals depends upon what is assumed regarding the level of support – paid for by customers – provided to offshore generators versus that in the OFTO regime.

If a higher level of support were to have been provided to cover a higher allocation of offshore transmission costs under the merchant counterfactuals, the consumer would be likely in a better cost position in the OFTO regime due to the lower level of total renewable support costs, albeit in return for taking on certain, relatively remote, stranding risks.

A

ANNEX A: DEVELOPMENT OF THE OFTO REGIME

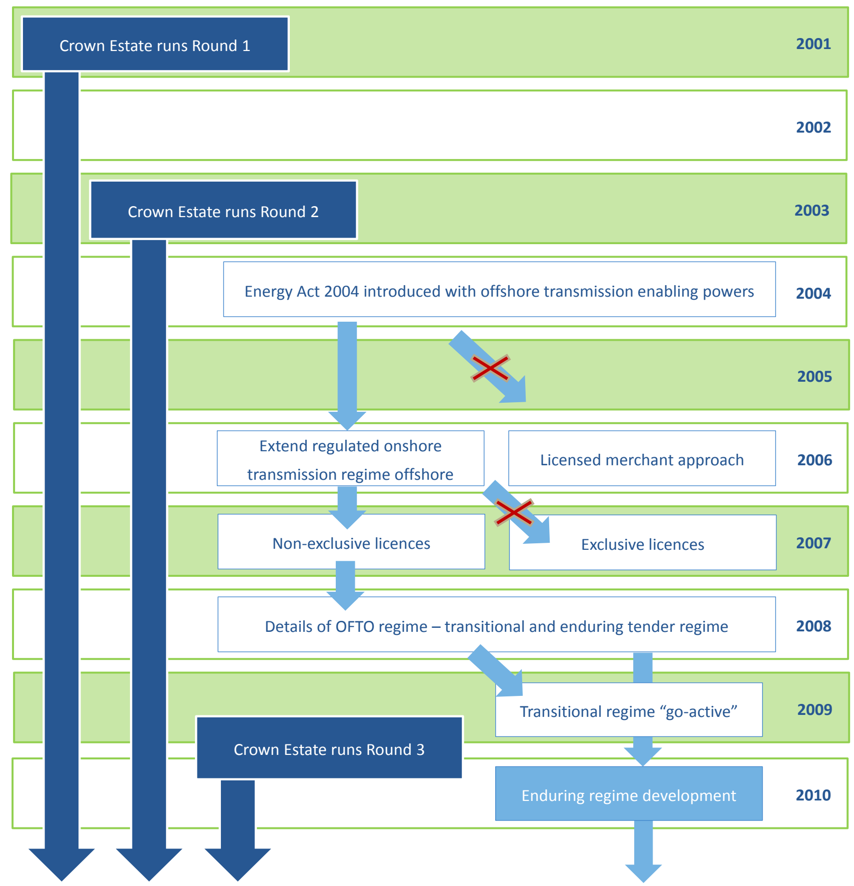
The OFTO regime and its development (1)

Timeline of the regime's development

Energy Act 2004:

- The enabling powers to introduce an offshore transmission regulatory regime were put in place through the 2004 Energy Act which extended licensing requirements to offshore generation and transmission.
- This was, in particular, to ensure that:
    - companies undertaking offshore transmission activities complied with the requirements of transmission codes, charging arrangements and technical standards; and
    - the Gas and Electricity Markets Authority (GEMA) could enforce compliance and protect electricity consumers.
- A timeline of the regime's development through this consultation process, alongside the development of Round 1, 2 and 3 projects, is illustrated in Figure A1.

Figure A1: Timeline of the OFTO regime's development



Regime identification

- The competitive based OFTO licensing regime emerged from a set of initial options for an offshore transmission regulatory regime that included a licensed price control based method or a licensed merchant approach (similar to how a number of gas and electricity interconnectors have been regulated in GB and Europe).[1]
- As Figure A2 shows, the charging arrangements for offshore transmission assets were an important part of the option development process.
- There was a concern that approaches that were not consistent with regulatory arrangements onshore, could prevent a level playing field for onshore and offshore generators.
- Different approaches could also place greater constraints on offshore generators having to meet the costs (either upfront or over the economic life of the assets) when connecting to the onshore transmission system.
- **Following a consultation process, the Government and Ofgem decided that a licensed price control approach was the optimal solution.**

Figure A2: Timeline of the OFTO regime's development

	Not considered practical	*Considered practical*		
Components	***Option 1***	***Option 2***	***Option 3***	***Option 4***
Overall regulatory regime design	Unlicensed or license exempt approach.	A price control regulated approach to offshore electricity transmission. Participation in offshore transmission would be a licensable activity.		A licensed merchant approach to offshore transmission.
Expected TO and SO role under regime	No details provided at the time as was not considered practicable or indeed even legally permissible because of the requirements of the Internal Market Electricity Directive (IMED).	Appointed offshore TO responsible for planning investment in networks. Option to extend NGC's remit as GBSO to encompass system operation offshore.		Licence could authorise developer to carry out SO and TO activities with respect offshore assets.
Approach to charging – who pays?		SO would recover TO costs via charging methods from electricity generators and suppliers.	As per Option 2 but with a degree of cost cross-subsidisation with other onshore users.	Offshore wind generators would meet all the costs upfront of developing the offshore link.
Key design principles	Effectively the "do nothing" option identified at the time.	Onshore and offshore consistency. Special licence conditions would establish price controls.	As per Option 2 but with greater cost socialisation to support offshore wind investment.	Light touch. Minimum regulatory arrangements consistent with IMED and Renewables Directive.

Note 1: Ofgem also explored whether a licence exempt merchant approach would have been feasible but the requirements of the Internal Market Electricity Directive (IMED) for regulated third party access was deemed to imply that a licence exempt approach was not feasible.

The OFTO regime and its development (3)

Regime development

In developing the licensed price control approach, the Government and Ofgem took into account the differing nature of the offshore environment and the powers that were provided under the Energy Act 2004:

- This included Energy Act powers for GEMA to make regulations about awarding offshore transmission licences on the basis of competition, although it was not required to do so.
- Taking these factors into account, it was concluded that conceptually there were two broad approaches for licensing Transmission Operator activities offshore organised, around regulated price control arrangements.
- These included non-exclusive licences and exclusive licences. Under these two broad options, five possible approaches were identified - two under the non-exclusive option and three under the exclusive option.
- Options that were ruled out included:
    - a non-exclusive approach whereby the offshore generator, rather than a third party, selects the transmission owner (the “generator tender” approach);
    - an exclusive approach whereby one licensee is appointed transmission owner for the entire offshore area (the “one zone” approach); and
    - an exclusive approach which would see the licences of the three existing onshore transmission licensees extended to cover adjacent offshore areas (the “extension” approach).
- Therefore, as illustrated overleaf, two options for licensing the offshore transmission connections between generators located in offshore waters and onshore networks were proposed for further consultation.

The OFTO regime and its development (4)

Core options for the licensed price control approach to offshore transmission

Overview of the options:

The Non-exclusive approach: involved GEMA issuing licences for offshore transmission zones or projects following a competitive tender undertaken by a third party (the "common tender" approach).

The Exclusive approach: was a system based on onshore network regulation, where a single TO would be responsible for responding to connection requests from generators in a certain geographical area.

Both options retained aspects of existing onshore arrangements, including a single System Operator and common connection application arrangements.

Figure A3: Refined options for GB offshore transmission regime

Components	*Non-exclusive*	*Exclusive*
Overall description	Authority issues non-exclusive offshore TO licences. TOs through a "common tender" bid to build, own, finance and operate assets.	Geographic monopolies would be established offshore according to a favoured "multi-zone" (e.g. strategic areas) approach.
Key principles	Objective to facilitate competition for the construction, ownership and operation of offshore transmission assets.	Single TO exclusively responsible for a defined geographic area. More limited use of competitive based tendering.
Other regime design aspects	Would retain the same approach to transmission charging as onshore and the principles of onshore connection applications.	Area based licences could be awarded by competitive tender. TO responds to all future connection requests from generators in area.
Regulatory comparators	Similar regulatory approach adopted for Independent Network Operators (IDNOs) and Independent Gas Transporters (IGTs).	Onshore transmission network arrangements.

Following a consultation process, the Government and Ofgem concluded that the non-exclusive "common tender" approach was the most appropriate model for licensing offshore transmission in GB.

B

ANNEX B: COUNTERFACTUAL 3 DEBT ASSUMPTIONS

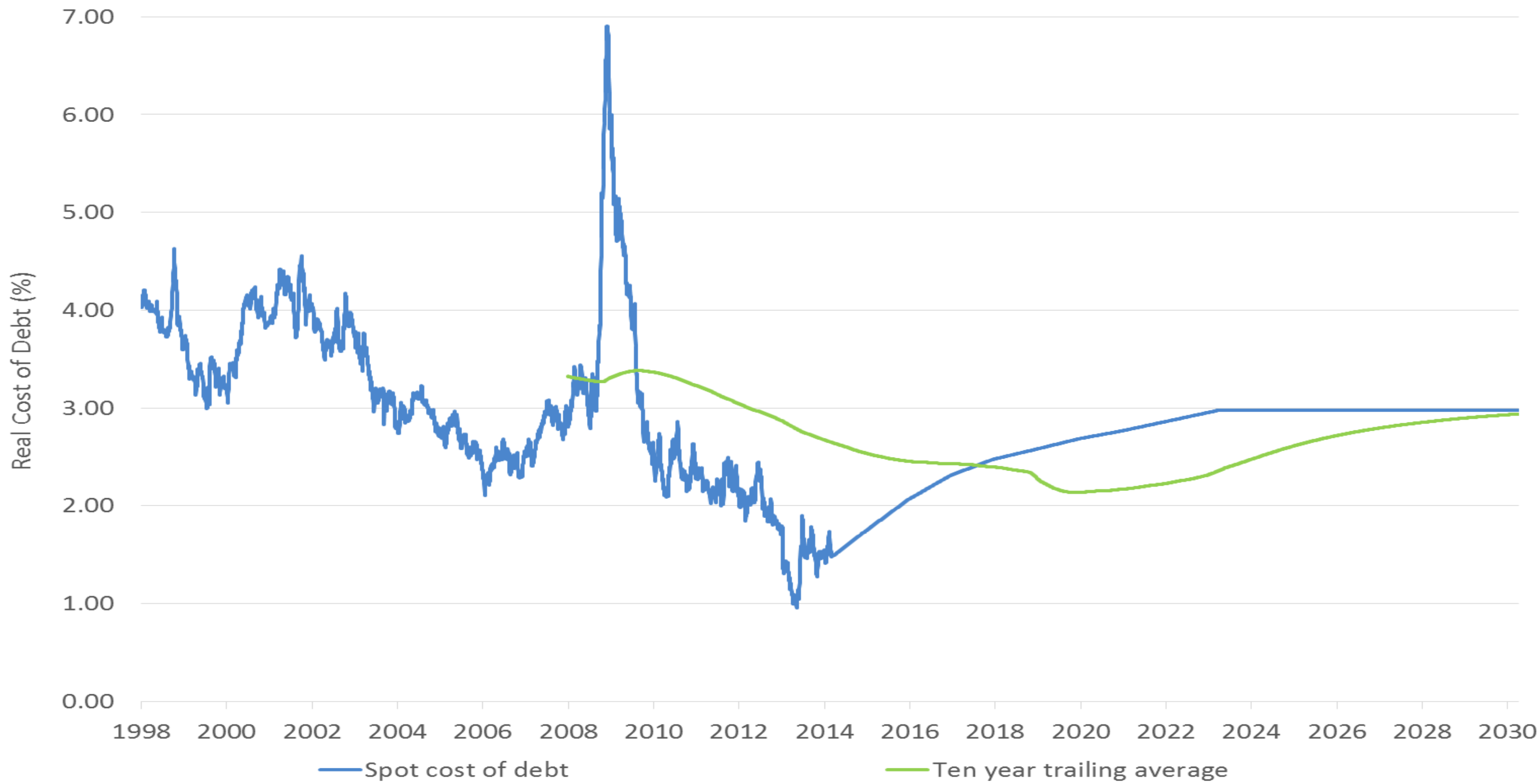
Counterfactual 3: Modelling the cost of debt

Under counterfactual 3, we model a cost of debt index over time based on the iBoxx indices used by Ofgem for the RIIO price controls and forward curves

- The indices are the iBoxx non-financial corporate ten year plus indices with broad A and BBB credit ratings in nominal terms. These are then deflated by ten year breakeven inflation, as published by the Bank of England, to deflate the cost of debt figures into real terms.
- This provides a spot cost of debt in real terms for each day, from which we then take a ten year trailing average.
- Ofgem apply the ten year trailing average for each financial year as the ten year trailing average of this combined index as estimated at the last working day in the preceding October (i.e. for the 2012/13 financial year, the cost of debt allowance is based upon the ten year trailing average as calculated at the end of October 2011).
- Historical data is available to us from the current point in time. To calculate the expected future rates for this index, we utilise forwards on UK ten year gilts and apply these changes in expected gilt yields to our spot cost of debt index.
- We use the full adjustment of the expected nominal gilt change to apply to the cost of debt index e.g. if the spot gilt yield is 2.0% today, the cost of debt spot rate is 3.5% today and gilts are expected to rise to 3.0% in one years' time, the expected cost of debt is calculated as being 4.5% (i.e. the original rate plus the change in gilt yield expectations).
- Another way of thinking of this is that the debt spread and inflation expectations remain constant under this assumption.
- We use the expected gilt changes for the forthcoming ten year period then assume that the spot cost of debt remains constant.
- We use the ten year trailing average of these figures across the index and use the end of October to apply to each financial year for the twenty years included within our CBA model.

Counterfactual 3: Modelling the cost of debt

Figure B1: Modelled cost of debt index



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