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Electricity transmission charging: assessment of options for change

Consultation

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Overview:

Ofgem is reviewing the current electricity transmission charging arrangements as part of 'Project TransmiT'. The aim of Project TransmiT is to ensure that arrangements are in place to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers.

Electricity generators and suppliers pay transmission charges for using the electricity transmission network. Transmission charges recover the costs of providing the transmission assets needed to transport electricity across the network. These charges are known as 'Transmission Network Use of System' (TNUoS) charges.

The current regime for setting TNUoS charges was introduced in 2005. The energy sector is now facing an unprecedented investment challenge driven by the need to connect large amounts of new generation to the electricity networks to meet climate change targets, while continuing to provide value for money for consumers and security of supply. This document discusses potential options for change to the TNUoS charging arrangements and our assessment of the impacts. These options have been developed by Ofgem and industry under the 'Significant Code Review' (SCR) on TNUoS charging, launched as part of Project TransmiT. This document sets out and seeks views on our assessment of the impacts of each of the options and our initial views of the way forward.

Subject to responses to this consultation, we expect to set out our final recommendations in spring 2012.

Context

Britain's energy sector is facing an unprecedented challenge. This is driven by the need to connect large amounts of new and low carbon generation to the electricity networks to meet climate change targets, while continuing to provide safe and reliable energy supplies at value for money for consumers today and in the future. As a result, electricity and gas networks are going through radical change.

The current electricity transmission charging regime has served consumers well by promoting the efficient use of the networks, and facilitating effective competition in generation and supply. However, the time is right for us to step back and consider whether the arrangements are fit to meet the challenges of the future. In particular, in 2010 Parliament clarified Ofgem's duties including our duty to have regard to the need to contribute to sustainable development. This supplements Ofgem's principal objective to protect the interests of consumers, amongst other things, in the reduction of electricity supply-related greenhouse gas emissions. It is echoed in Ofgem's new objectives and duties under the European Third Package. Further, following the implementation of proposals to change the way the industry is governed, industry parties and Ofgem now have the ability to instigate changes to the charging arrangements.

Against this background, Ofgem launched Project TransmiT in September 2010 by issuing a call for evidence. We subsequently launched a Significant Code Review to consider if any changes may be required to the electricity transmission charging arrangements.

Associated documents

Project TransmiT: a call for evidence, September 2010, Reference number 119/10
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT

Scope of Project TransmiT and summary of responses to our call for evidence, January 2011
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=80&refer=Networks/Trans/PT

Project TransmiT: approach to electricity transmission charging work, May 2011, Reference number 73/11
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=114&refer=Networks/Trans/PT

Project TransmiT: electricity transmission charging Significant Code Review launch statement, July 2011
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=141&refer=Networks/Trans/PT

Other relevant documents are available on the Project TransmiT 'Web Forum':
http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Pages/WebForum.aspx

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Executive Summary

The current transmission charging regime has served consumers well by promoting the efficient use of the networks, and facilitating effective competition in generation and supply. However, the mix of electricity generators is changing. In particular, there are an increasing number of small and variable generators, such as wind and marine, wanting to connect to the system. The time is therefore right for us to step back and consider whether the arrangements are fit to meet the challenges of the future.

Project TransmiT is Ofgem's independent and open review of transmission charging and associated connection arrangements. The aim of Project TransmiT is to ensure that arrangements are in place to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers. This document focuses on the electricity transmission charging issues that we are considering and sets out, for consultation, our initial view on the future direction of charging.

We are committed to conducting Project TransmiT in an open, inclusive and transparent manner. As well as consulting thoroughly with stakeholders, we have provided a range of opportunities for stakeholders to engage and feed into the options we have developed and the outcomes of the modelling work. The consultative nature of the process has been instrumental in contributing to the body of evidence and stimulating debate.

We have considered three main charging options under Project TransmiT. These are:

- **Status Quo** (Investment Cost Related Pricing (ICRP)): retaining the existing Transmission Network Use of System (TNUoS) charging methodology and making incremental changes to reflect issues previously unanticipated (e.g. high voltage direct current (HVDC) and island connections).
- **Improved ICRP**: incrementally changing the current charging approach to improve the accuracy of cost targeting.
- **Socialisation**: recovering transmission costs through a uniform £/MWh tariff applied to all generation users, whatever their type and location. Similarly another set of uniform tariffs would apply to demand users.

We have also examined two further policy variants:

- **Improved ICRP variant**: which excludes converter station costs in HVDC expansion factors under improved ICRP for those links that parallel the onshore AC network (i.e. not those that are radial in nature).
- **Socialisation variant**: retains a local tariff in the generation TNUoS tariff, so that only the costs of the wider network are socialised.

We have assessed these options against the three broad aims of the project: (i) deployment of low carbon generation across Great Britain (GB) and impact on achieving the UK government's Renewable Energy Strategy target of 30% of generation from renewable sources by 2020 and carbon intensity in 2030, (ii) quality and security of supply across GB, and (iii) overall cost of the system as a whole and customer bill impacts.

We have also considered aspects of wider sustainable development as well distributional impacts and a number of practical issues.

The charging options result in very different patterns of charges across generators. However, they are all consistent with meeting the UK government's 2020 renewable target and carbon intensity goals with no material differences in the implications for security of supply. The key differences between the options are the impacts on power sector costs and consumer bills.

Based on the evidence and our assessment of it, **we are consulting on ruling out socialised charging as an option for transmission charging**. This is because:

- For any given level of government support the socialised approach reduces the risk of not meeting the UK government's 2020 renewable generation target. However in order to meet these targets, it does so at disproportionate cost (to 2020 power sector costs would increase by £2.8bn, pushing up consumer bills by £6.9bn).
- It would exacerbate existing regional patterns of fuel poverty.
- Socialising wider asset charges only reduces costs and consumer bill impacts compared to full socialisation, but they are still significantly higher than for status quo and improved ICRP (consumer bills rise by £4.8bn to 2020).
- It risks straying into areas of UK government policy around the degree of support for low carbon generation, which could cause confusion.

If we do rule out socialised charging, we consider it is important to reaffirm the principle of cost reflectivity in transmission charging. However, the choice between improved ICRP and retaining the status quo is not clear cut.

Under improved ICRP society would benefit from a small reduction in power sector costs (£120m savings to 2020) compared to the status quo. Customer bills would be largely unaffected in the early years and whilst they rise after 2017 (£0.9bn rise to 2020) the effects are small as measured against total costs. Notwithstanding this, we believe improved ICRP better reflects the costs variable generators impose on the need for transmission investment and more accurately reflects the economic trade-off each Transmission Owner makes between expected constraint costs and the cost of new transmission reinforcements when planning investment activity. Improved ICRP would also appear to be more consistent with the direction of European policy and would represent a relatively low risk evolution of the existing approach.

Consequently, **our initial view, for consultation, is that improved ICRP is the right direction for transmission charges**.

However, we have modelled only one form of improved ICRP. Others are possible and may result in more benefits and lower bills for consumers. Further work by National Grid Electricity Transmission plc (NGET) and industry partners is necessary to refine the form of improved ICRP.

We welcome responses to our initial views. Should our final recommendations identify that change is necessary, we will issue a direction to NGET to bring forward an appropriate modification to the charging approach.

1. Introduction

Overview

1.1. Project TransmiT is Ofgem's independent and open review of transmission charging and associated connection arrangements. The aim of Project TransmiT is to ensure that we have in place arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers.

1.2. Electricity connections issues (such as timely connections and user commitment) and electricity transmission charging are the priorities for Project TransmiT. This document focuses on the electricity transmission charging issues that we are considering under Project TransmiT. We are taking forward our work on connections separately[1].

1.3. This document consults on the way forward. Appendix 3 sets out our impact assessment as required by section 5A of the Utilities Act.

1.4. We are grateful to stakeholders for their considerable input into the process to date.

Charging framework

1.5. Electricity generators and suppliers pay transmission charges for using the electricity transmission network. Transmission charges recover the costs of providing the transmission assets needed to transport electricity across the network. These charges are known as 'Transmission Network Use of System' (TNUoS) charges.

1.6. National Grid Electricity Transmission plc (NGET) is responsible, in conjunction with other stakeholders as appropriate[2], for ensuring that appropriate electricity transmission charging arrangements are in place. Ofgem's role is to set out the principles that NGET must adopt in carrying out this role and provide support and challenge as necessary to achieve this. Ultimately, our role is to approve any appropriate changes to the charging methodology developed by NGET and industry.

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[1] An update on our connections work can be found on our website: http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Timely%20connections.pdf

[2] NGET has transmission licence obligations to have transmission charging methodologies in place, to keep its methodologies under review at all times and to make proposals to modify those methodologies where it considers a modification would better achieve the relevant objectives. The process for modifying the methodologies is contained within the Connection and Uses of System Code (CUSC). Modifications can be proposed by NGET, CUSC Parties, BSC Parties, the National Consumer Council, the CUSC Modifications Panel, Relevant Transmission licensees (in relation to Exhibit O Part IB and IIB only) or by a Materially Affected Party, unless otherwise permitted by the Authority.

1.7. NGET is obliged under its transmission licence to establish and keep under review appropriate transmission charging methodologies for the electricity transmission system[3]. The current licence obligations require NGET to have in place charging methodologies that, amongst other things, facilitate competition in generation and supply, and result in charges that, as far as is reasonably practicable, reflect the costs that have been incurred by licensees.[4]

1.8. The current transmission charging methodologies have applied across Great Britain (GB) since the introduction of the single electricity market through the British Electricity Trading and Transmission Arrangements (BETTA) on 1 April 2005. BETTA extended the existing charging regime for England and Wales to include Scotland. However, the principle of cost reflective charging has been a feature of the Use of System charging approach in England and Wales since 1990.

1.9. These charges are calculated using a methodology called investment cost related pricing (ICRP), which assesses the impact of adding a MW of generation or demand at different locations on transmission costs. It results in a locational element which is intended to give users of the transmission system, both generators and demand users, signals that reflect the economic costs of establishing and operating transmission infrastructure.

1.10. These locational signals, when incorporated into individual financial appraisals, allow market participants to trade-off transmission charges against other cost considerations. Market participants are able to weigh the costs of transmission against other costs and operating efficiencies which are likely to vary by location. Depending on their location and technology, relevant factors may include: different land costs, different labour costs, potential load factors, different fuel costs, and different electricity transmission infrastructure costs.

1.11. Locational signals should, therefore, allow participants to make efficient commercial decisions about where to locate new generation and when to close existing generation, thereby assisting in the development of an economically efficient transmission system.

[3] These requirements are set out in the standard licence condition SLC C4 and SLC C5 of NGET's electricity transmission licence.

[4] On 10 November 2011, the Electricity and Gas (Internal Markets) Regulations 2011 came into force, which implement the Third Package of EU legislation on the internal gas and electricity markets. The regulations introduce a new code objective to a number of industry codes and charging methodologies regarding a requirement for future code changes to comply with the EU Third Package Regulation (Regulation (EC) 714/2009) and any relevant legally binding decisions of the EU Commission and/or the Agency for the Cooperation of European Regulators (ACER). The Third Package implementing regulations in error did not make a similar change to SLC C5 to incorporate a new code objective for the Use of System Charging Methodology. The Authority intends to make an appropriate licence change in due course to include the new objective. We recommend that the CUSC Committee should be cognisant of this in considering future amendment proposals pending the licence change being made. The Third Package implementing regulations can be viewed at the following link: http://www.legislation.gov.uk/uksi/2011/2704/contents/made

1.12. Further information on the existing TNUoS charging arrangements is available from our website[5]. Further technical detail is available from NGET's website[6].

1.13. The current transmission charging regime has served consumers well by promoting the efficient use of the networks, and facilitating effective competition in generation and supply. However, the mix of electricity generators is changing. In particular, there are an increasing number of small and variable generators, such as wind, wanting to connect to the system. The time is therefore right for us to step back and consider whether the arrangements are fit to meet the challenges of the future.

Structure of this document

1.14. The remainder of this document is structured as follows:

- Chapter 2 – describes our process to date
- Chapter 3 – sets out the charging options that we have developed with industry under the SCR and the modelling approach
- Chapter 4 – discusses the outcome of the modelling work we have commissioned
- Chapter 5 – contains our wider sustainability assessment
- Chapter 6 - sets out our initial views
- Chapter 7 – sets out next steps
- Appendix 1 – provides information on responding to this consultation
- Appendix 2 – sets out the policy sensitivity results
- Appendix 3 – contains our impact assessment
- Appendix 4 – provides an overview of the technical working group discussion
- Appendix 5 – contains the feedback questionnaire

[5] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Project_TransmiT_A_Call_for_Evidence_Technical_Annex.pdf
[6] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/

2. Process to date

Call for evidence

2.1. We launched Project TransmiT in September 2010 by issuing a call for evidence[7]. Our call for evidence invited views on the extent to which Project TransmiT should focus on transmission charging and connection issues, on generation/entry and demand/exit issues, and on electricity and gas issues. Amongst other things, respondents commented on the following high-level themes:

- Whilst there was some concern about the potentially wide ranging nature of the review, there was broad support for Project TransmiT and the majority of respondents agreed with the proposed objective and scope of the review.

- There was a widely held view in responses that the immediate focus of TransmiT should be on both electricity transmission charging and electricity connection issues (such as user commitment and facilitating delivery of timely connections). Many respondents considered that electricity connection issues were at least as pressing (if not more pressing) than electricity transmission charging issues. There was also a view that TransmiT should focus on both generation and demand considerations.

- In relation to the electricity charging arrangements, there were mixed views on the benefits of cost reflectivity, which is a stated principle of the current electricity transmission charging arrangements. Although many saw benefits in some element of cost reflectivity, there were questions about the appropriate strength of locational signals. Some respondents considered that a move to uniform charging, or a weaker cost reflective signal, would better facilitate the move to a low carbon energy sector.

- A number of respondents commented on gas issues, including on certain aspects of the entry and exit charging arrangements. Most of those that commented did not consider that gas was an immediate priority for Project TransmiT.

2.2. We issued an open letter in January 2011[8], confirming that the immediate priority of Project TransmiT would be electricity connection issues and electricity transmission charging.

2.3. We are committed to conducting Project TransmiT in an open and transparent manner. We established a dedicated web forum for Project TransmiT in September 2010. The web forum provides stakeholders with an opportunity to contribute to Project TransmiT by providing us (and other interested parties) with analysis and

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[7] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT
[8] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110125_TransmiT_Scope_Letter_Final.pdf

papers that can be posted on the Ofgem website. We note that this forum has been extensively used as a means of contributing to the body of evidence and stimulating debate.

Academics' reports on charging

2.4. Following the launch of Project TransmiT, we appointed a number of teams of independent academics to produce reports on the GB charging arrangements. We asked three academic teams to provide us with their independent views on the optimal approach to transmission charging for GB, with a particular focus on the electricity transmission charging regime. We commissioned another academic adviser to assess whether transmission charging arrangements should be a vehicle to promote low carbon generation and, if so, how. We appointed a further academic to conduct a peer review of the academics' reports, and separately commissioned a review of international transmission charging arrangements.

2.5. The academics' and consultant's reports are published on our web forum[9].

Scope of TransmiT

2.6. From the work carried out by our academic advisors, dialogue with stakeholders and responses to our call for evidence, interactions with our work on network constraints, and participation in discussions in Europe, we identified a spectrum of emerging options. The range of options reflects the divergent views on the importance of cost reflectivity and about the ability of the current arrangements to help deliver a balanced, sustainable and diverse generation mix cost effectively for consumers.

2.7. In May 2011[10] we consulted on how best to carry forward our work on Project TransmiT. In the consultation we noted that there were two broad groups of emerging options:

- Options that may imply wider change to the current GB trading arrangements.[11]
- Options to change transmission charging (TNUoS) alone.

2.8. We recognise that external developments (e.g. development of the European Target model, UK government legislative changes, etc) may lead to the need to evolve the GB market regime and therefore aspects of the current regulatory framework. However, the exact form of these changes and the scale of their impact on transmission charging in GB is uncertain at this time and we note that such risks

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[9] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Pages/WebForum.aspx
[10] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf
[11] Two of the four teams of academics we appointed support options which, amongst other things, would introduce a locational element to wholesale energy prices.

are ever present. We also wish any justified changes to be made in a timely way, so as to realise any benefits to existing and future consumers as soon as possible.

2.9. Having considered the views of stakeholders, we also considered there to be merit in assessing which, if any, of the options limited to arrangements that seek to recover the costs of providing transmission assets alone, could potentially deliver the aims of Project TransmiT and bring benefits to consumers in the shorter term.

2.10. Against this background, we explained in our May 2011 consultation that options that would require more fundamental change to the electricity transmission charging and wholesale market arrangements would not be included within the scope of Project TransmiT. We noted that we will continue to consider the consequences of European developments for the arrangements in GB and whether these developments imply the need for reform of the GB market. We also consulted on our proposal to launch a SCR to focus on potential short-term changes to the current TNUoS arrangements. We remain committed to future consideration of European developments on GB charging arrangements.

Significant Code Review

2.11. Following responses to our May 2011 consultation we launched a 'Significant Code Review' (SCR) on electricity transmission charging in July 2011[12] to assess a range of potential options for TNUoS changes from:

> ***Socialised charging***: whereby part or all of transmission costs are recovered through the same uniform tariff applied to all generation users, whatever their type and wherever they are located. Similarly another set of uniform tariffs would apply to demand users;
>
> to
>
> ***Improved 'Incremental Cost Related Pricing' (or 'improved ICRP'):*** which modifies the existing ICRP approach to improve the accuracy of the locational signals, taking account of generators' different characteristics.

2.12. A key part of the SCR has been the quantitative modelling of the impact of these different options.

2.13. There was broad consensus from industry in support of our decision to exclude options that imply potentially more fundamental change (i.e. options that could impact on the GB market arrangements) from the scope of Project TransmiT and the SCR.

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12 http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110707_Final%20launch%20SCR%20statement.pdf

2.14. As noted above, the SCR process is seeking to make any justified changes in a timely way, so as to realise any benefits to existing and future consumers as soon as possible. The aim of the SCR is therefore to review the current principles on which the charging arrangements are based and to identify any appropriate changes limited to the current transmission use of system charging arrangements.

Technical working group

2.15. To help us identify and specify potential alternative charging methodologies to be assessed we established and chaired a technical working group (WG) of 14 industry participants[13], representing a wide range of stakeholder interests. The purpose of the working group was to assist with developing the technical detail of the potential options for change.

2.16. Detailed responses to our original Call for Evidence plus other feedback from stakeholders identified a number of concerns and issues with the existing approach to transmission charging. These issues and concerns were grouped into six themes[14]:

Theme
1. Reflecting characteristics of users
2. Geographical/ topological cost differentiation
3. Treatment of security provision
4. Reflecting new transmission technology
5. Unit cost of transmission capacity
6. Generation and Demand (G:D) split

2.17. Between July and November 2011 the WG met eight times to develop the technical detail of the potential options for change. They did this by examining the issues raised by stakeholders and considering the range of possible choices for addressing them under each charging approach. This was done for each of the six themes to arrive at a view of the most appropriate technical detail for the alternative charging approaches.

2.18. Section 11 of the Report of the Technical Working Group summarises the WG's recommendations for the technical detail of the different charging approaches, highlighting where consensus was reached and where options remained. The summary tables from that report, setting out the areas of consensus and areas where Ofgem was required to make a decision, are reproduced in Appendix 4.

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[13] The membership and TOR for the WG are available on our website at: http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%20Initial%20Report.pdf

[14] More information on the themes was presented to the WG and is available from the Ofgem web forum: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=118&refer=Networks/Trans/PT/WF and http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/Transmit%20charging%20list%20WG3.pdf

2.19. Agendas, papers and minutes for the WG meetings are available on our website[15]. The working group report has also been published on Ofgem's website[16].

Modelling work

2.20. We appointed external consultants, Redpoint Energy Limited (Redpoint), to carry out detailed modelling work for the SCR. This identified the potential impacts of the different candidate options for change. We provided Redpoint with the technical detail of charging options for the modelling exercise, drawing on the work carried out by the WG.

2.21. To undertake the analysis Redpoint developed a modelling framework in conjunction with Ofgem and NGET that incorporated modules for transmission charging, system dispatch, market pricing, constraint forecasting, and generation and transmission investment decision making. Feedback was sought from the WG on the methodology and assumptions, and a number of updates to the approach were made on the basis of this feedback.

2.22. We recognise that there are almost unlimited variations of transmission charging that could be assessed. However, this must be balanced against several practical restrictions. For example, the modelling process is complex and takes considerable time and effort to construct, refine and run. Furthermore, because we are seeking to make any justified changes in a timely way to raise any benefits as soon as possible, it makes sense to move as quickly as practicable to identify potential improvements.

2.23. For practical purposes we therefore sought to identify a small number of charging approaches that could be expected to be considered by the broadest spectrum of stakeholders to be 'front runners for success' across each of the six broad themes identified for potential change. We consider that, with the collaboration of industry, it has not been necessary to model every permutation to determine a robust way forward.

Wider stakeholder engagement

2.24. We have also engaged with the wider stakeholder community throughout the process. We have held two wider stakeholder events to provide general updates on the progress of our work and to seek feedback in June and August 2011. Initial modelling results were also presented at the event in August and a further update provided at a stakeholder event in November 2011.

[15]http://www.ofgem.gov.uk/NETWORKS/TRANS/PT/WF/Pages/WebForum.aspx
[16] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=166&refer=Networks/Trans/PT/WF

3. Charging options and modelling approach

Charging options

3.1. Under Project TransmiT, we have assessed a range of potential options for TNUoS changes from socialised charging to improved ICRP.

3.2. As noted in chapter 2, the WG played a pivotal role in helping us to decide the precise options that we should model. In particular, the WG provided input into the development of the technical detail associated with the alternative charging approaches. In ultimately determining the details of the modelling options, we built on the advice of the WG and also took into consideration:

- The aims of Project TransmiT.
- All the information received since the launch of Project TransmiT.
- Evaluation of whether the WG has provided a robust justification for a proposed alternative.
- Technical information from NGET, as owner of the TNUoS charging methodology and associated information system arrangements, on the possible development and implementation timescales of the possible options (noting a key objective of the SCR process is to facilitate appropriate changes in a timely way to raise any benefits as soon as possible).

3.3. As a result of these considerations we decided to model three core approaches – status quo, improved ICRP and socialised, plus one variant each of improved ICRP and socialised. These models are summarised below:

Table 1: Summary of base case transmission charging options[17]

	Status Quo	Improved ICRP	Socialised
Wider investment	Locational	As for Status Quo	Socialised
Local asset charges	Asset specific	As for Status Quo	No locational differentiation
G:D split	27%:73%, moving to 15%:85% from 1 April 2015	As for Status Quo	As for Status Quo
Wider tariff	Capacity based (MW)	Dual criteria, based on two part 'peak' and 'year round' tariff; with the year round element multiplied by a specific load factor (calculated ex-ante based on historical data)	Energy based (MWh)

[17] Note that in all scenarios we asked Redpoint to assume that there would be no change to the current connection/use of system charging boundary, the mechanism for recovering the costs of balancing services (including constraint costs), which are currently recovered equally across all users, and that uniform location loss factors would apply.

	Status Quo	Improved ICRP	Socialised
HVDC lines: expansion factor	Full costs, including converter stations	No change from Status Quo	Not relevant
HVDC lines: treatment in load flow modelling	Apportioning flows in proportion relative to circuit ratings across key network boundaries	No change from Status Quo	Not relevant
Local security factors	No change from current methodology	As for Status Quo, but for island links, security factor effectively reduced to 1.0 where there is no redundancy	Not relevant

3.4. Based on the outcomes of discussion at the WG we also instructed Redpoint to conduct sensitivity analysis on two variants of the alternative charging option designs, reflecting two of the key points of discussions in the WG:

- An **improved ICRP policy sensitivity** which excludes converter station costs in HVDC expansion factors under improved ICRP for those links that parallel the onshore AC network (i.e. not those that are radial in nature).[18]
- A **socialised policy sensitivity** which retains asset-specific local charges (£/kW) under the Socialised model, with the uniform tariff only replacing wider[19] charges.[20]

Modelling approach

Objectives

3.5. The key objective of the modelling is to provide quantitative evidence of how each charging approach might best facilitate the aims of Project TransmiT; to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers.

3.6. In practice this has meant modelling the impact of alternative charging options on:

[18] Under this approach, the expansion factor (i.e. multiple of 400kV OHL costs) for HVDC links was to be re-calculated to exclude the costs of the converters, thereby reducing the effect on locational tariffs, but not completely removing the cost from the locational signal. Hence, wider tariffs do not increase to the same extent as they would under the base case Improved ICRP option.

[19] The TNUoS tariff for use of assets in the deeper transmission infrastructure (known as the 'Main Interconnected Transmission System' (MITS), or 'wider' network) is split into two component parts; a locational element and a residual element. The locational element covers all investments in "locational" assets (e.g. wires). The residual element recovers costs of "non-locational" assets (e.g. substations) that contribute to overall security. The two elements combined are referred to as the wider zonal tariff.

[20] This modelling approach was constructed to reflect the view of some WG members that the defining feature of the socialised approach, a uniform tariff for use of the MITS network, should be central to a modelling approach but considered that a cost reflective tariff for infrastructure assets that do not meet the MITS boundary criteria (as established under ECM-11) should also be investigated.

- The deployment of low carbon generation across GB and the impact on achieving the government's Renewable Energy Strategy target of 30% of generation from renewable sources by 2020.[21]
- The de-rated generation capacity margin of the system. Note that a capacity mechanism is included in the modelling approach to reflect the UK government's Electricity Market Reform (EMR)[22] proposals.
- The impact on avoidable 'power sector costs' (a welfare measure representing the change in total cost to society of meeting electricity demand) and the impact on 'consumer bills'.

3.7. The impacts of alternative charging options were quantified by reference to the status quo counterfactual, facilitating comparison across charging options. The modelling approach is designed to indicate the change across options rather than the absolute level of costs.

3.8. In order to undertake effective cost/benefit analysis of the different options and to ensure consistency with prior Ofgem models, generation decisions on new build/retirement and transmission investments are modelled endogenously (i.e. built into the model). In other words, optimal investments are chosen according to the model's decision rules, and are influenced by the different transmission charges under each option.

3.9. To achieve the above aims we commissioned Redpoint to develop a modelling tool with the following main features:

- **Least cost optimisation or "perfect foresight"**: simulates full (or perfect) information about future outcomes, economically rational behaviour and ability to react instantly to signals on transmission charges and generator locations. Under this approach generation and transmission investors react to each other's investment plans every year until the globally optimal combination of investments is determined.
- **Agent simulation or "imperfect foresight"**: simulates expected player behaviour under uncertain conditions and models how players react to various policy options assuming imperfect information about how other parties will react and a limited view of how future prices will develop.

3.10. The results in this document are based on the imperfect foresight modelling[23].

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[21] The EU Climate and Energy package, formally agreed in April 2009, commits the EU to achieving an increase in use of renewable energy by 2020 compared with 1990 levels. The package includes a binding renewable target of 20%. The UK's share of this target is to deliver 15% renewable energy by 2020. The UK government's Renewable Energy Strategy, published in June 2009, suggested that the UK electricity (RES-E) target could be best achieved by renewable generation providing about 30% of the total electricity generation by 2020.
[22] Further information on the UK government's EMR work is available from the DECC website: http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx
[23] This approach was discussed at WG 7 where it was explained that the Perfect Foresight analysis showed that where convergence occurred the results were similar to the Imperfect Foresight results.

Modelling approach to low carbon support

3.11. There are important interactions between transmission charging and the levels of support that different forms of low carbon generation require if they are to be built. Whilst Project TransmiT is a review of TNUoS charging, the interactions with the UK government's EMR need to be taken into account.

3.12. Different charging options have the potential to lead to significantly different volumes of low carbon generation for any given level of low carbon support[24] and could impact the level of support required to meet any particular target. Nonetheless, transmission charging is only one element in the delivery of renewable deployment in line with the UK government's environmental targets, along with the level of external subsidy available.

3.13. Government has yet to set the level of support (in the form of Contract for Differences, or CfDs) for low carbon generators to be introduced under EMR. However, the UK government has indicated that it will take into account the effect on low carbon deployment of the result of the TransmiT project in setting subsidy levels.

3.14. Redpoint's modelling therefore assumes a simplified interaction between transmission charging and low carbon support options. This is based on the view that:

- We consider it is robust to assume that the EMR work will set low carbon support to ensure that the legally binding 2020 renewable target is met.[25]
- It is not appropriate for Ofgem to 'pick winners' in terms of technology growth/entry/exit or attempt to second guess the evolution of the EMR low carbon support policy to meet the overarching policy targets across the modelling horizon.

3.15. To capture these different effects, a simplified interaction between TNUoS and low carbon support was undertaken in the modelling exercise through the analysis of two different bases:

- Equivalent levels of low carbon support across the three base case options (and two variants) in order to isolate the impacts of the different charging options on deployment rates **("Stage 1").**
- Adjusted levels of low carbon support to deliver the same renewable output in 2020 and carbon intensity in 2030 for all charging options, to facilitate the comparison of costs between them **("Stage 2").**

3.16. In the Stage 1 modelling, low carbon support for the status quo model is set to ensure the legally binding 2020 renewable target is met and a level of carbon

[24] "Low carbon" includes onshore wind, offshore wind, biomass, wave/tidal, nuclear and CCS.
[25] In accordance with the UK government's Renewable Energy Strategy.

intensity consistent with the current policy intention of ~100 g/kWh[26] by 2030 is delivered . These support levels are technology specific, based on the estimated long run marginal cost of each technology[27]. These same support levels are then applied to the other charging approaches, allowing the impact of transmission charging alone on renewable deployment to be identified.

3.17. Stage 2 assumes that DECC sets the levels of low carbon support so that renewable targets are met whatever the transmission charging approach. The aim of Stage 2 modelling is to uniformly adjust the level of low carbon support (CfD strike price) in the other charging approaches to achieve an outcome comparable to the low carbon support targets reached in status quo (comparable in the sense that the 2020 and 2030 targets are met in all cases, but not necessarily by the same plant mix). We are of the view that the stage 2 modelling is representative of likely 'real world' outcomes for low carbon support, and allows costs to be compared across policy options since each delivers broadly equivalent renewable energy and carbon intensity outcomes.

Input assumption sensitivities

3.18. Redpoint carried out two sensitivity analyses around input assumptions for the status quo, socialised and improved ICRP approaches:

- An **RO-banding sensitivity** was constructed after the launch of the Government's consultation on revised Renewables Obligation banding levels. In response to stakeholder feedback, we considered it important to re-run the Stage 1 modelling under revised assumptions to understand better the impact of the charging options assuming no further changes to existing levels of renewables support before 2020.[28]

- A **low gas price sensitivity** which is based on a 15% reduction in gas prices in all years, relative to the base case assumptions. This sensitivity was chosen in recognition of the uncertainty surrounding future gas price and the importance of coal and gas price differentials in driving constraint costs.

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[26] 50 g/kWh recommended by the Committee on Climate Change (CCC) in its 4th Budget Report, which the Government recently accepted (2023-2027), but 100 g/kWh was assumed in the analysis supporting DECC's EMR Consultation.
[27] More detail is provided in Redpoint's report.
[28] In this sensitivity, the proposed RO bands contained in the UK government's consultation on the Renewables Obligation banding review, published in October 2011, have been applied until 31 March 2017. From 1 April 2017, CfDs are set at levels equivalent to the remuneration under the RO (including power and LEC revenues). All results are based on imperfect foresight.

4. Modelling results: impact of options

Question box

Question 1: Do respondents consider that we have appropriately identified and where possible quantified the impacts of the Project TransmiT options?

Question 2: Do respondents consider that there are additional impacts which we should take into account in the decision making process and, if so, what are these?

Question 3: Do respondents consider that we have appropriately identified the potential interactions of the Project TransmiT options?

Question 4: Do respondents consider that we have appropriately identified the likely impacts or consequences of these interactions?

Introduction

4.1. In considering the implications of the alternative modelling approaches to TNUoS charging, we have taken into account, amongst other things, the analysis undertaken by Redpoint and the views of wider stakeholders received throughout this process. This chapter assesses the proposals against the objectives of Project TransmiT.

4.2. In this section we summarise the overall quantitative analyses conducted by Redpoint for the three core charging options. This section is complemented by Appendix 2 which provides a further assessment of the impacts. This document in its entirety forms our assessment of the impacts of the options.

4.3. We present the following types of impacts for status quo, improved ICRP and socialised charging:

- **Impacts on transmission charges:** transmission charges are a factor influencing the decisions of generators regarding where to locate their plant, and which plant to retire[29]. The signals provided by charges are one cost consideration that can therefore affect generation deployment and power sector costs.
- **Impacts on sustainability goals:** estimated using the results of Stage 1 modelling, with low carbon support held fixed across the charging options

[29] The location of generating plant on the system also affects the level of constraint costs which will drive future decisions on when and where to reinforce the transmission network. These reinforcements then feed into transmission charges which then also influence generators' decisions. This in turn affects the level of transmission charges.

- **Impacts on security of supply**: measured using de-rated capacity margins, based on Stage 2 modelling.
- **Overall cost impacts**: based on Stage 2 modelling.
- **Cost-benefit analysis and distributional impacts**: aggregate impacts on power sector costs and consumer bills, also based on Stage 2 modelling.

4.4. The impacts of alternative charging options on power sector costs and consumer bills are quantified by comparison to the status quo counterfactual.

Impacts on transmission charges

Overview

4.5. The allowed revenue that the transmission companies are allowed to collect, known as the Maximum Allowed Revenue (MAR)[30] under status quo is projected to increase over the next 20 years. This is because as new generation capacity (particularly renewables) is connected to the system it leads to greater expenditure on transmission network reinforcements. The modelling suggests that this would be reflected in increasing charges on average under any transmission charging option.

4.6. Increases in MAR for socialised and improved ICRP are broadly similar, but for socialised charging the increase in MAR is significantly higher. This is because of an increase in onshore and offshore wind build, at sites that are more remote and further offshore.

4.7. Currently 27% of MAR is recovered through charges on generators and 73% from charges on demand. The modelling changes this to 15:85 in 2015 to remain compliant with EU Tariffication Guidelines which reduces generation tariffs and increases demand charges.

Generator TNUoS: improved ICRP

4.8. Improved ICRP involves a dual background (peak security and year round) approach for assessing the incremental transmission network costs imposed by generators. A generator's TNUoS charge would therefore be comprised of the following four components:

- ***A peak security wider tariff:*** charged on Transmission Entry Capacity (TEC) (MW) and levied only on those generators which have a high probability of

[30] TNUoS charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control.

operating at significant volumes during peak demand periods (e.g. conventional baseload plant). The peak security wider tariff for intermittent generators will be zero (for both positive and negative tariff zones) due to its lack of contribution to the need for transmission network investment to ensure demand security.

- ***Year round wider tariff***: charged on TEC (MW) scaled by a moving average actual load factor specific to each generator.
- ***Residual element***: ensures the necessary revenue recovery[31]. The wider tariff components noted above are added to the network-wide residual to calculate the total wider TNUoS tariff. The improved ICRP proposal would not alter the residual calculation relative to the status quo.
- ***Local tariff***[32]**:** The improved ICRP proposal will not alter the local substation or local circuit charges calculation (or the extent to which circuits are defined as local or wider), and therefore would have no impact on local tariff relative to the status quo.

4.9. The peak security wider tariff would have a relatively small impact on total charges. It is the use of load factor in the year-round wider tariff element that would have the largest impact on generator tariffs relative to the status quo. Consequently, although total revenue requirements are similar across the two options, there would be significant differences in TNUoS charges to generators under improved ICRP, in particular for low load factor generators. Relative to the status quo option, low load factor generators in positive charging zones would see lower transmission tariffs under the improved ICRP methodology, and vice versa in negative charging zones. The effect would be more pronounced for variable / intermittent generators who would not pay the peak security wider tariff.

4.10. The impact of this is shown for 2012 in figure 1. In general, the modelling results suggest that the effect of the improved ICRP approach is to 'compress' locational variations in generation TNUoS charges, particularly for low load factor generators including variable and intermittent renewables[33]. The spread of charges for lower load thermal plant is smaller than that for baseload generators due to lower load factors, but is generally wider than for variable / intermittent generators.

4.11. Wider tariffs (i.e. including the residual but excluding the local tariff) under status quo range from minus £14/kW in London (the cheapest zone) to about £25/kW in North Scotland and the Western Highlands and Skye (the most expensive zone)[34]. Under improved ICRP, tariffs range from minus £2/kW (London) to £18/kW

[31] To ensure the correct level of revenue is collected through each locational charge, a 27:73 split will be obtained for each triggering criterion 'pot', without altering the size of the total pot.

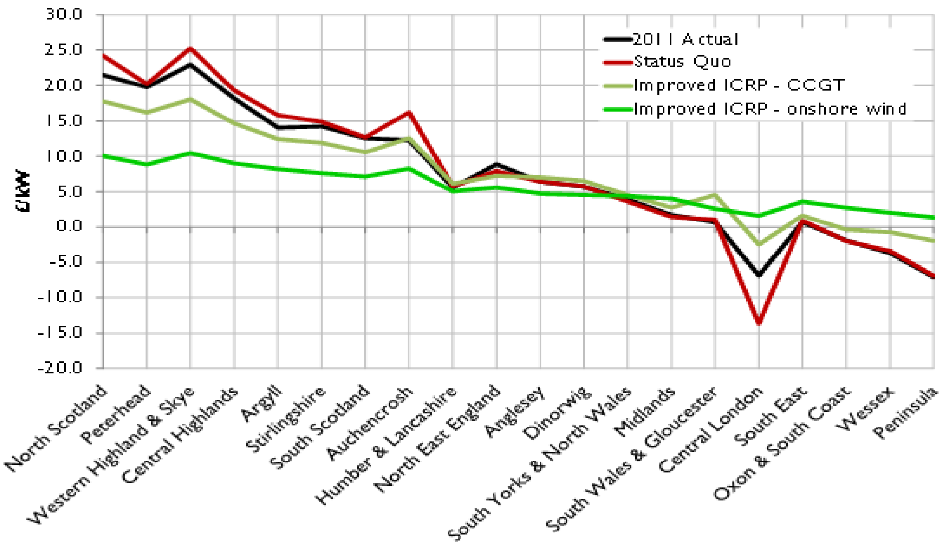
[32] It is proposed to levy on the wider element of charge only because "local" infrastructure reflect elements of transmission build made for a specific user (or users), which therefore limit the potential for sharing of transmission network capacity and, as such, are sized to that user's (or users) capacity. Hence, the Local transmission charge elements reflect the full cost of the build rather than an amount based on its usage.

[33] The difference in improved ICRP average tariffs between onshore wind and wave & tidal is explained by a higher assumed load factor (40%) for wave and tidal.

[34] Note there is no difference in charges for baseload and intermittent generators under the current Status Quo approach.

(North Scotland) for high load factor generators, and from about £1/kW to £10/kW for low load factor generators across the same zones.

Figure 1: Indicative average wider TNUoS tariffs for all generation zones (2012)



4.12. As a result, and all else being equal, zones which currently have high TNUoS charges, such as North Scotland, become more attractive for siting plant with lower load factors (including low load factor thermal generation) and zones which currently have low positive, or negative TNUoS tariffs, such as the south of England, become less attractive for plant with this characteristic.

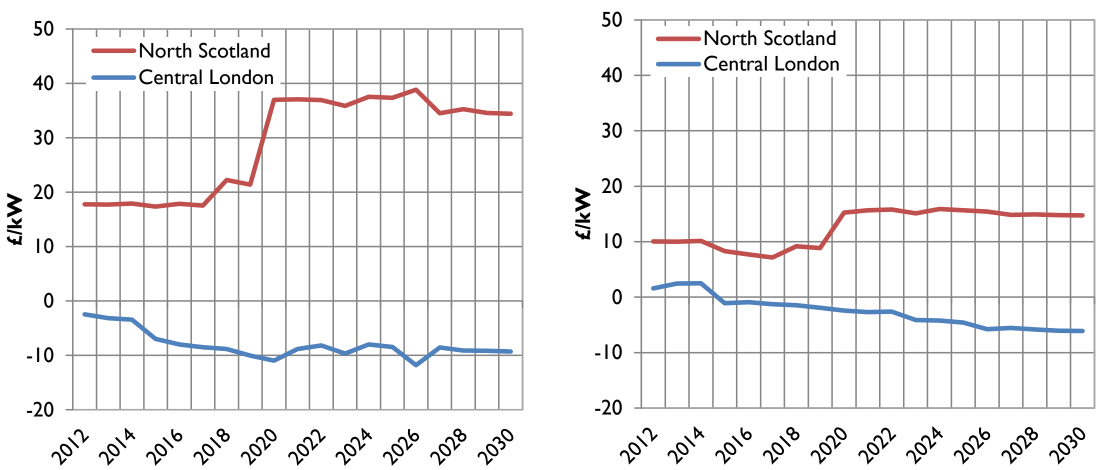
4.13. A key difference between the status quo and improved ICRP approaches is the assumed security factor multiplier used in the calculation of tariffs for island links that become part of the main interconnected transmission system (MITS). For improved ICRP we have assumed that the security factor multiplier would effectively be lowered for links with no redundancy on the sub-sea component of the transmission link, even for links that meet the MITS criterion[35] (and form part of the 'wider' network for charging purposes). This would mean that the global security factor multiplier (currently 1.8) would be used for all circuits that meet the MITS boundary criteria except for the single sub-sea circuit between the island group and the mainland that would have a specific factor of 1.0 for this section of cable. This assumption lowers future transmission tariffs for use of the proposed links to the Scottish island groups of Orkney and Western Isles (and therefore island generators) relative to the status quo. Shetland is not expected to become part of the MITS and is therefore unaffected by this.

[35] As defined in 14.15.54-6 of NGET's Methodology Statement.

4.14. Figure 2 shows the projected evolution of tariffs for North Scotland and Central London (on average) coming from the model over the period to 2030. These tariff changes are driven by changes in MAR, the G:D split and specific transmission reinforcement decisions. For example, charges for generators located in North Scotland in 2020 increase as a consequence of the planned HVDC reinforcement projects.

Figure 2: Improved ICRP base case

Baseload[36] **Intermittent**



Demand TNUoS: improved ICRP

4.15. Differences in demand TNUoS charges between status quo and improved ICRP are relatively minor, driven almost entirely by differences in generation and transmission backgrounds. This is because the methodology for calculating demand charges is the same. The exceptions are following the commissioning of new HVDC links which tend to lead to lower demand charges in Northern Scotland.

Generator TNUoS: socialised

4.16. By making all charges uniform, the socialised approach would have a very significant impact on locational price signals for generators. Generators that are currently in high TNUoS charging zones would face lower charges. This is particularly the case for generators with low load factors (such as wind generators) as these generators will generate less MWh for the same TEC (the basis for status

[36] Baseload generator assumes 100% load factor at peak and 70% annual load factor. Intermittent generator assumed 28% annual load factor, representing a typical onshore wind generator and no use of system at peak.

quo charges). Conversely, generators currently in low or negative TNUoS charging zones would face higher charges, particularly those operating at high load factors.

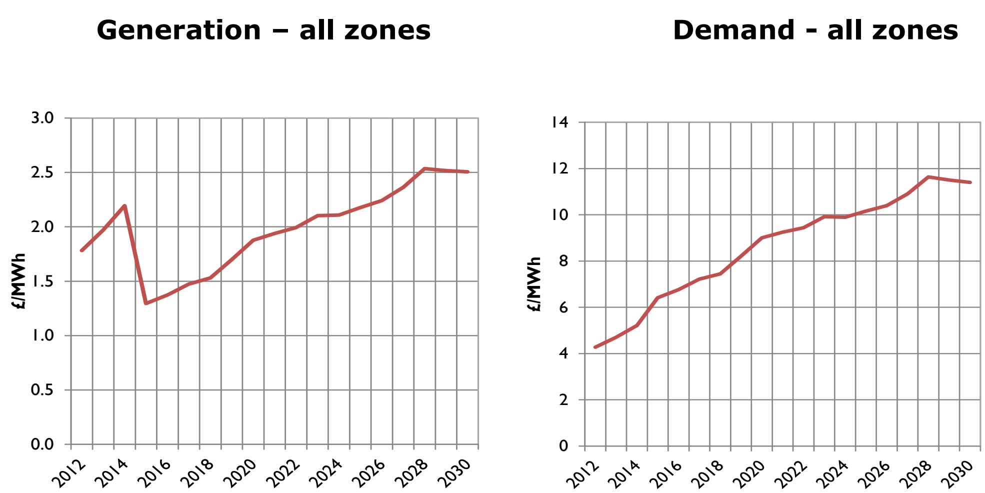
4.17. Hence, zones which currently have high TNUoS zonal tariffs (e.g. North Scotland and Western Isles & Skye) become relatively more attractive for siting plant, particularly for lower load factor generators, all else being equal. Areas which currently have low positive, or negative zonal TNUoS tariffs, such as the south of England, become relatively less attractive for plant generally, relative to the status quo. Offshore generators would also benefit under the socialised approach, since under the model chosen for analysis the costs of local assets[37] would also be shared, reducing, significantly in some cases, the TNUoS tariff paid to recover the costs of the offshore transmission owner (OFTO) asset relative to the status quo.

4.18. Charges increase rapidly over time under the socialised approach (see figure 3) because of the increase in MAR. The reduction in charges in 2015 reflects the assumed change in the G:D split to remain compliant with EU Tariffication Guidelines.

Demand TNUoS: socialised

4.19. Socialised demand tariffs would also be very different to status quo, resulting in tariff increases in Scotland and the north (and other relatively low tariff zones currently) and lower charges in London and the south. Again, tariffs rise rapidly because of increases in MAR and the assumed change to the G:D split.

Figure 3: Socialised TNUoS charges (all zones)



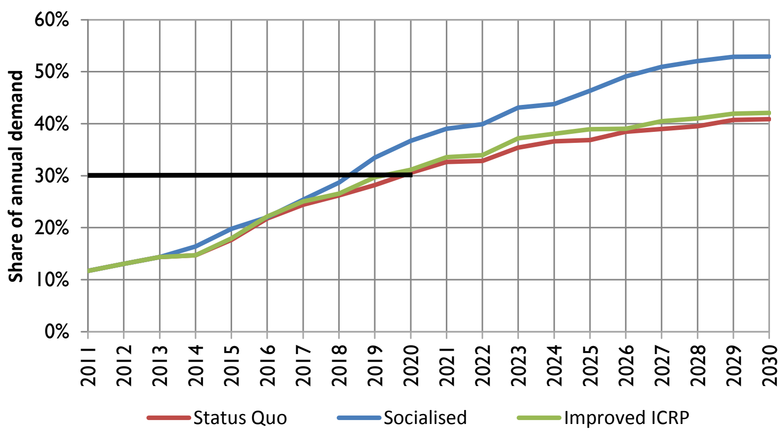
[37] We also included the sensitivity where local asset charges would be retained within a Socialised approach as presented below.

Impacts on sustainability goals

Overview

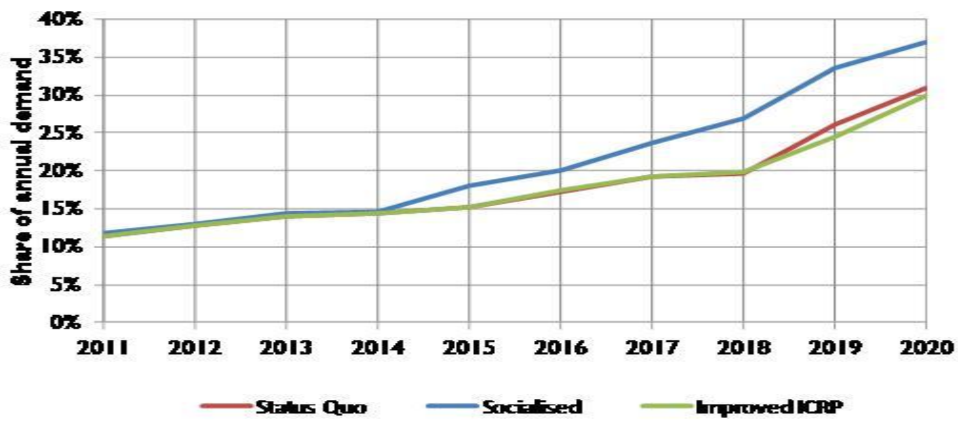
4.20. The impact of the different charging approaches on the sustainability goal is best assessed using the stage 1 modelling. This involves setting low carbon support under the status quo to deliver renewable generation and carbon intensity targets and then applying the same level of support to the other options. The results of this are summarised in figure 4.

Figure 4: Renewable generation, 2011 – 2030 (stage 1 modelling)



4.21. We have also tested the impact on deployment of retaining the levels of support at levels consistent with those in the recently announced Renewables Obligation re-banding review. The stage 1 modelling results suggest that all base case charging approaches meet the legally binding 2020 target. However, socialised charging could be expected to result in the most renewable generation (hitting 30% of total demand one and a half years early and 37% of total demand in 2020 versus the target of 30%).

Figure 5: Renewable generation, 2011-2020 (assuming existing levels of low carbon support)



4.22. The following sections consider the effects on sustainability of both the improved ICRP and socialised charging approach in more detail.

Sustainability: improved ICRP

4.23. The modelling suggests that, for the same level of low carbon support, improved ICRP could somewhat increase the probability of hitting the 2020 renewables target, relative to the status quo, by increasing the deployment of onshore wind in Scotland. For the same level of support, renewables output hits 30% of total demand in mid to late 2019 and is 0.6 percentage points higher than the status quo by 2020.

4.24. In terms of capacity mix, the key difference between improved ICRP and status quo by 2020 is an additional 1.5 GW of onshore wind built under improved ICRP as a consequence of reduced wider TNUoS tariffs for low load factor generators in positive TNUoS zones. Accordingly, slightly less baseload generation is required to meet demand.

Sustainability: socialised

4.25. Under socialised, the modelling results indicate that renewable output is 6.2 percentage points higher by 2020 relative to the status quo, thereby reducing the risk of missing the 2020 target if the levels of low carbon support do not deliver.

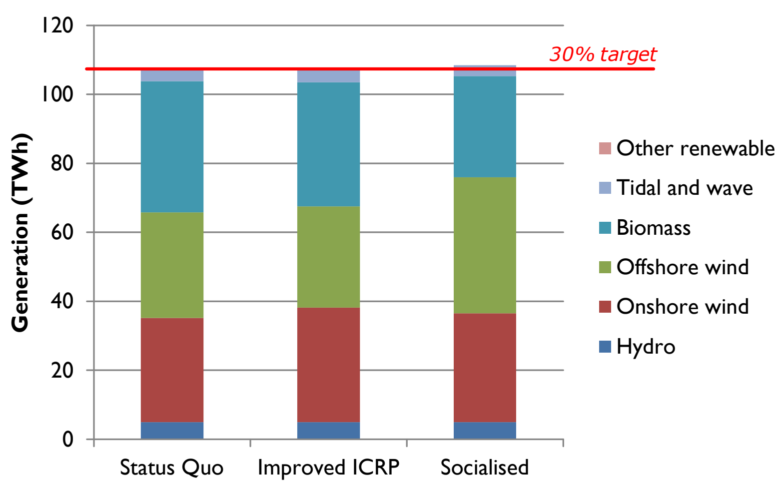
4.26. In terms of capacity mix, the modelling suggests that there are more significant differences under socialised charging relative to status quo. In particular, the modelling suggests that socialised charging would further facilitate the deployment of new renewables, resulting in an additional 1.5 GW of onshore and 6.8 GW of offshore wind by 2020 compared to the status quo, due to lower charges for low load factor generators in the north and offshore. As a result, the bulk of the additional renewable generation in 2020 under socialised charging would come from offshore wind.

4.27. The modelling also suggests less nuclear capacity by 2030 and slightly less biomass generation compared to the status quo. Both effects are the result of load factor influences on charging. As a baseload generator with a high load factor, nuclear would be expected to pay an increased level of charge under the socialised approach. The effect is exacerbated by the fact that many of the pre-designated nuclear sites are in the south of England and would otherwise have benefitted from low or even negative locational charges under the status quo. High load factors are also associated with biomass plant and the location of most available projects in the south, where transmission charges are relatively low under the status quo, and would rise under a socialised approach.

Sustainability: stage 2 modelling

4.28. In the stage 2 modelling low carbon support levels are adjusted to ensure that each charging approach delivers broadly the same level of renewable output. Even so, the change in capacity mix observed in the stage 1 results carries through to the stage 2 results, with socialised charging involving a greater reliance on offshore wind. This effect is highlighted in the figure below.

Figure 6: Renewable generation deployment to meet 2020 target – stage 2 modelling



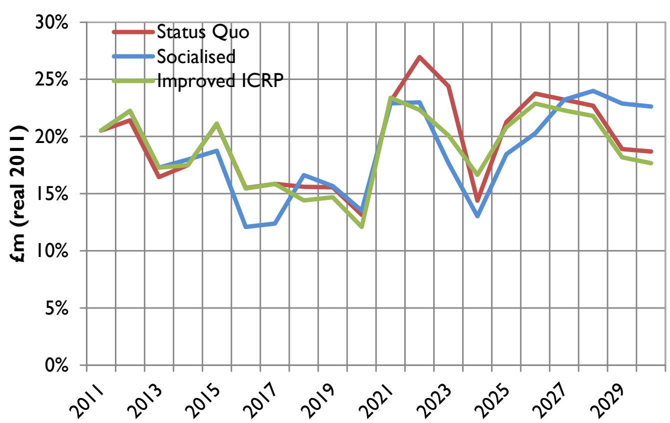
Impacts on security of supply

4.29. Redpoint's analysis assumes a simple capacity mechanism is implemented to reflect the policy intention of the EMR. With this mechanism in place security of supply is similar across all three options (and their variants). Modelled de-rated capacity margins (see figure 7 below) are similar across the three base case options to 2020 and do not drop below 12%.

4.30. In general, de-rated capacity margins are slightly lower under the socialised approach, which in the near term is the result of more rapid retirement of older gas plant currently benefiting from low or negative TNUoS charges. In the longer term this reflects slightly delayed new Combined Cycle Gas Turbine (CCGT) investment for similar reasons.

4.31. Removing the capacity mechanism assumption would reduce the de-rated capacity margin across all options and possibly lead to regional security of supply issues under all options. Nonetheless, we consider it is robust to assume that the EMR work will develop a capacity mechanism to continue to ensure security of supply across the modelling horizon.[38]

Figure 7: De-rated capacity margins (Stage 2 modelling)



Impacts on overall costs

Overview

4.32. Overall cost impacts are compared using the stage 2 analysis, which adjusts levels of low carbon support so that each charging approach results in broadly equivalent levels of renewable generation, facilitating comparison on a 'like with like' basis. All results in this section are based on the Stage 2 modelling.

4.33. The assessment focuses on the impact of socialised and improved ICRP charging versus the status quo on avoidable 'power sector costs' and 'consumer bills'. Power sector costs are used as a welfare measure as they represent the change in total cost to society of meeting electricity demand. Consumer bill impacts are not an overall welfare measure, but rather the impact on just one part of society. The difference between impacts on power sector costs and on consumer bills is

[38] On 16 December 2011, the UK government announced its intention to bring in a market-wide power capacity mechanism. More information is available from DECC's website: http://www.decc.gov.uk/en/content/cms/news/emr_wms/emr_wms.aspx

producer surplus, which represents earnings by generators and transmission owners above their long-run cost of delivering electricity (i.e. changes in profits in the power sector).

Impact on overall costs

4.34. Table 2 shows the impact on total power sector costs relative to status quo for the period to 2020 under the improved ICRP and socialised charging options.

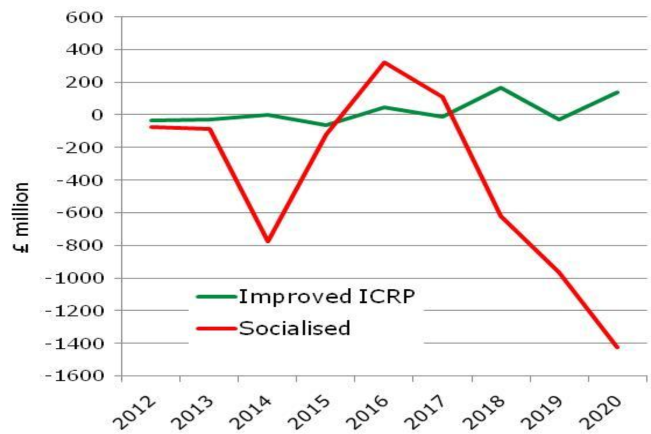
Table 2: Power sector cost analysis (Stage 2 modelling)[39]

NPV 2012 to 2020 (at 3.5%) - £mn real		
	Improved ICRP	Socialised
Generation costs	-313	-453
Transmission costs	8	1,569
Constraint costs	171	1,452
Carbon costs	11	201
Total impact on power sector costs	**-122**	**2,769**

4.35. This shows a small net benefit of £122m for improved ICRP, accruing mostly towards the end of the period, and significant net costs for socialised of £2.8bn (largely due to high transmission and constraint costs). The year by year numbers are illustrated in figure 8.

[39] Positive figures represent cost increases relative to the status quo. Negative numbers represent cost decreases (savings) relative to the status quo.

Figure 8: Net benefit of total power sector cost analysis



4.36. Between 2021 and 2030 power sector costs under improved ICRP are projected by the model to be slightly higher (~£500m) overall relative to the status quo. This is explained by increased penetration of low load factor generation, the majority of which will connect at more peripheral locations, placing an upward pressure on the current level of constraint costs, which, in turn, will drive future decisions on when and where to reinforce the transmission network. This feedback loop is seen to increase transmission costs to a level where they ultimately offset the low generation costs observed up to 2020. However, the differences with the status quo are small relative to the overall cost of supplying electricity in this period.

4.37. For socialised charging power sector costs between 2021 and 2030 continue to rise, totalling £10.8bn over this period, driven by transmission costs of £7.9bn and constraint costs of £4.5bn due largely to the increasing volume of offshore wind generation.

Generation costs

Improved ICRP

4.38. Generation costs are forecast to fall by £300m in the period to 2020 because of increased deployment of renewable generation and reductions in fuel and fixed operating costs as a result. There is also a geographical shift in the location of onshore wind towards northern Scotland, saving generation costs through a higher average load factor.

4.39. After 2020, generation costs follow a similar trajectory under improved ICRP. The analysis indicates that there is a saving of £965m in generation costs under improved ICRP up to 2030.

Socialised

4.40. With socialised charging, generation costs are expected to fall by £453m in the period to 2020, compared to the status quo. This effect is the result of a shift in location of renewable build to exploit higher resource sites. In particular, onshore wind moves to northern Scotland, exploiting the higher average load factor available there, and offshore wind build moves from the Irish Sea and Moray Firth zones to relatively shallower locations at Dogger Bank and Hornsea, resulting in savings in generation costs. The resulting fuel and operating cost reductions are partly offset by higher capital costs, but overall savings remain.

Transmission costs

Improved ICRP

4.41. Transmission reinforcement decisions respond to the volume and location of generation capacity based on the economic trade-off between expected constraint costs on different boundaries and the cost of new transmission reinforcements. In the case of improved ICRP, transmission costs are forecast to rise slightly versus under the status quo, by £8m in the period to 2020 (see table 2 above).

4.42. The increase in transmission costs under improved ICRP (and socialised) charging is driven in particular by the increase in onshore wind build in the North of Scotland, which brings forward the build of new HVDC links that reinforce boundaries between northern Scotland and demand centres further south. Figure 9 shows that onshore transmission reinforcement costs are higher than those under socialised between 2018 and 2021 as a result of these relatively high capital cost investment projects being brought forward.

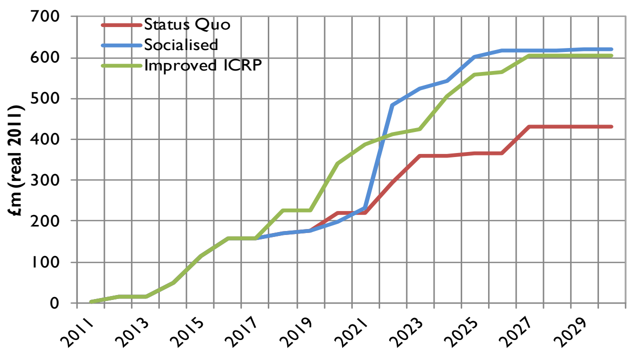
Socialised

4.43. Transmission costs under socialised charges are expected to be considerably higher than under the status quo, totalling an additional £1.6bn in the period to 2020 (see table 2 above). This is a consequence of the significant increases in onshore wind in North Scotland and offshore wind in locations that are shallow (and therefore lower cost to build) but further offshore, such as Dogger Bank. This additional capacity remote from the MITS infrastructure brings forward the need for costly radial offshore connections and increased reinforcement onshore.

4.44. Figure 9 shows that onshore transmission reinforcements are brought forward (relative to the status quo), but at a slower rate than that observed under improved ICRP. However, the reduced level of transmission cost relative to improved ICRP up to 2021 is eradicated after this time because the wider geographical spread of build under socialised triggers a need for earlier build of additional reinforcement projects, for example the Humber-Walpole HVDC link.

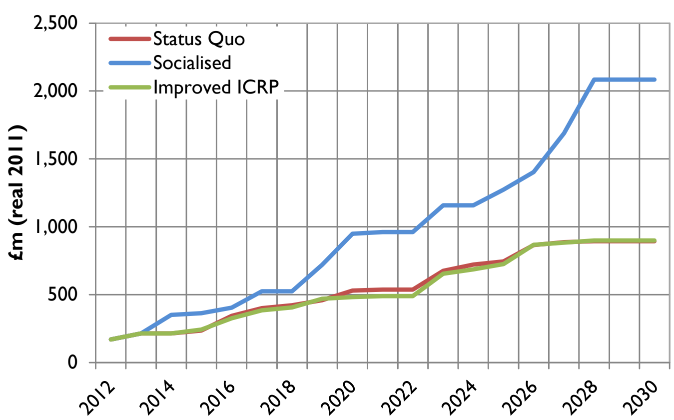
4.45. The impact on cumulative transmission investment is shown in figure 9.

Figure 9: Modelled reinforcement costs to the MITS



4.46. Offshore transmission build is also important to total transmission costs. There are further increases in transmission costs under socialised charging due to an increase in offshore wind build, at sites that are further offshore (for example, Dogger Bank is developed under socialised, but not under the other policy options). Under improved ICRP, on the other hand, offshore transmission costs are slightly lower than under the status quo (see Figure 10), offsetting additional costs from onshore reinforcement. The overall costs of onshore, offshore and island transmission are reflected in differences in the maximum allowed revenue for transmission owners.

Figure 10: Offshore and island transmission: cumulative investment costs



Constraint costs

Improved ICRP

4.47. Redpoint's analysis suggests that constraint costs are similar between improved ICRP and status quo until 2020, rising by £170m. This indicates that additional transmission reinforcement under improved ICRP is sufficient to relieve most of the additional transmission constraints associated with more onshore wind in northern Scotland.

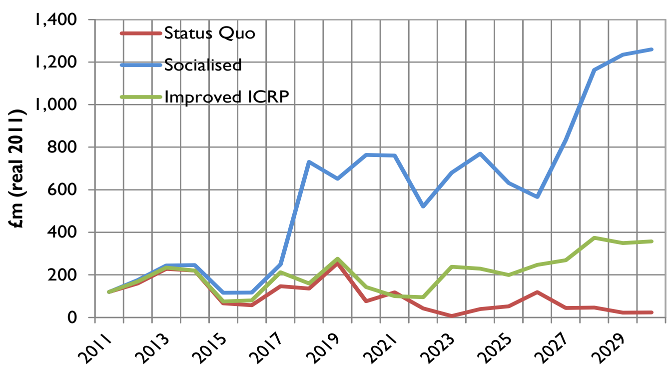
4.48. After 2020, the level of reinforcements does not quite keep pace with the greater levels of renewable deployment in Scotland and constraint costs rise as a result relative to the status quo.

Socialised

4.49. Constraint costs under socialised are forecast to be £1.5bn higher than under the status quo in the period to 2020, with costs rising rapidly after 2017.

4.50. These increased costs are explained by the different locational pattern of build, of both renewables and CCGT. The analysis suggests that the rate of transmission reinforcement does not keep pace with the increase in constraint costs caused by this generation pattern. By 2025, the possible reinforcements assumed in the model (based on available data) are exhausted and hence constraint costs continue to increase after 2025. It is possible that some of these constraints could be reduced if more transmission reinforcement options were available, but this would require additional spend on transmission reinforcement, which would itself impose more cost. Figure 11 illustrates the trajectory of constraint costs under each of the alternative charging options.

Figure 11: Constaint costs (£m)



Consumer bills

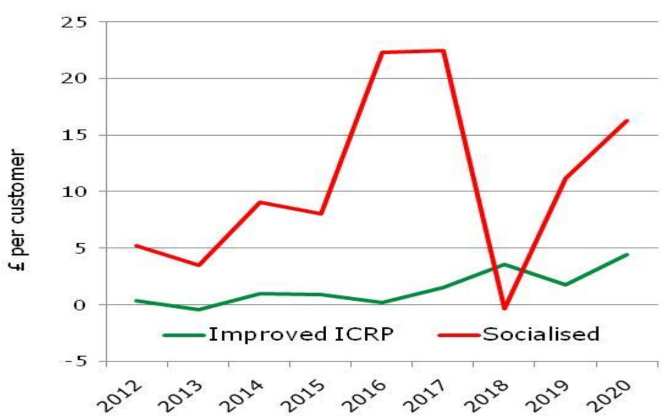
4.51. The impact of improved ICRP and socialised charging relative to the status quo on consumer bills from 2012 to 2020 is summarised in table 3. This shows costs for consumers of £0.9bn for improved ICRP and £6.9bn for socialised.

Table 3: Consumer bill cost analysis (Stage 2 modelling)

NPV 2012 to 2020 (at 3.5%) - £mn real		
	Improved ICRP	**Socialised**
Wholesale costs (inc BSUoS, losses & capacity payments)	1,436	7,433
Demand TNUoS charges	-98	849
Low carbon support	-441	-1,406
Total impact on consumer bills	**897**	**6,876**

4.52. The year to year impact on average bills is set out in figure 12. Socialised charging has a significant impact on consumer bills from the outset, whereas under improved ICRP the bill impacts are close to zero in the early years, before rising after 2017. However, in the context of total costs, these improved ICRP bill increases are small. Moreover, we note that higher prices could result in a more efficient market outcome if they more accurately reflect all the relevant costs. Whilst a suppressed price is better for consumers in the short-run, it is inefficient and may ultimately damage consumer interest in the long-run. As such we would have to consider the increase in consumer bills with market efficiency in mind.

Figure 12: Change in average consumer bills versus status quo



Wholesale costs

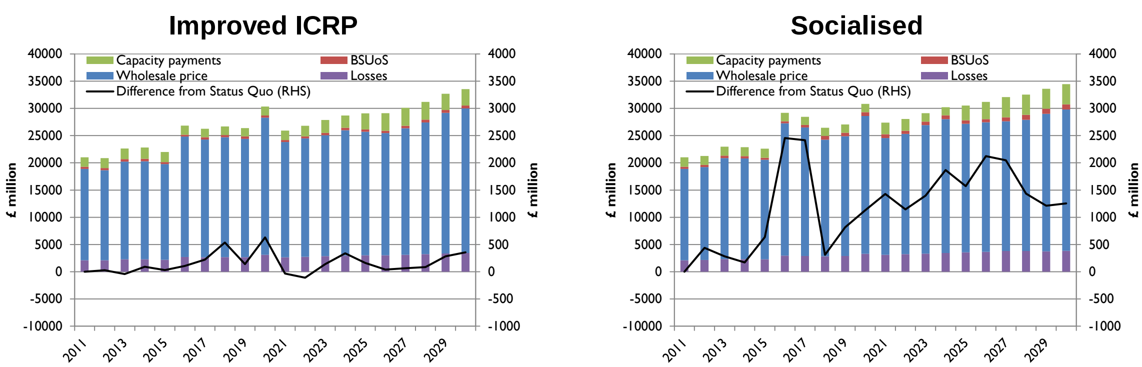
4.53. The relationship between power sector costs and consumer bills is complex. The main driver of increased bills is higher wholesale prices caused by small reductions in capacity margins between 2016-2020 due to earlier retirements of some plant that benefit from negative TNUoS charges under the status quo.

4.54. In addition, under socialised charging there is an immediate increase in wholesale costs due to an increase in the short-run marginal cost element of market prices as a result of introducing energy based (£/MWh) transmission tariffs. The combination of these factors results in consumer bills increasing by more than the increase in power sector costs under socialised. After 2020, these effects become less important and the higher consumer bills under socialised broadly reflect the higher power sector costs.

4.55. A component of the increase in wholesale costs under the alternative charging options is also due to higher Balancing Services Use of System (BSUoS) charges due to higher constraint costs, and higher transmission losses. The latter increases as a result of increased generating capacity in northern GB.

4.56. The impact on wholesale costs of both improved ICRP and socialised charging is summarised in figure 13.

Figure 13: Impact on wholesale costs



Demand TNUoS charges and low carbon support

4.57. The analysis suggests lower demand TNUoS charges of £98m under improved ICRP in the period to 2020 relative to the status quo. By contrast, with socialised charging demand TNUoS charges are expected to rise by £849m versus status quo, because of the higher MAR resulting from the greater transmission investment under this option.

4.58. Both charging options have lower low carbon support requirements than status quo (£400m for improved ICRP, £1.4bn for socialised), but these are not sufficient to offset higher wholesale costs and demand TNUoS charges.

Consumer bills: regional impacts

4.59. Regional impacts on consumers will be driven by differences in demand TNUoS charges. Under the status quo, demand charges vary by location for 14 different charging zones. They are highest in the south and lowest in the north and Scotland.

4.60. Differences in demand TNUoS charges between the status quo and improved ICRP are relatively minor, driven entirely by differences in generation and transmission backgrounds. This is because the methodology for calculating demand charges is the same across these two charging approaches.

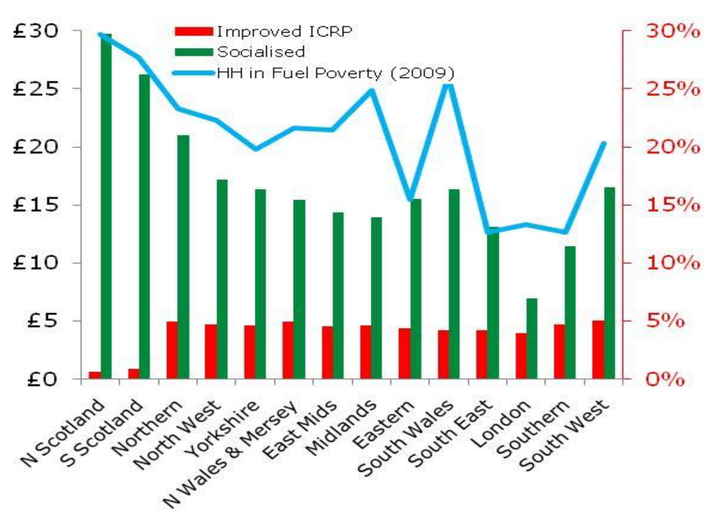
4.61. By contrast, differences between the status quo and socialised are significant. Under socialised charging demand TNUoS charges do not vary by location, and so compared to the status quo would increase in Scotland and the north and fall in the south. The impact of this for an average customer is shown in table 4.

Table 4: Change in demand TNUoS component of consumer bills for average domestic consumer, relative to the status quo in 2012

	Improved ICRP	Socialised
	£/year	**£/year**
N Scotland	£0.43	£11.24
S Scotland	£0.11	£7.37
N England	-£0.15	£2.26
Midlands & N Wales	-£0.28	-£0.38
S England & S Wales	£0.16	-£2.33

4.62. Assuming other consumer costs – wholesale costs, BSUoS costs, transmission losses and low carbon support – are passed through to customers equally, these regional TNUoS changes will feed through to final bills. The impact of this in 2020 is illustrated in figure 14, which also shows the correlation between regional bill increases under socialised and existing regional patterns of fuel poverty.

Figure 14: Change in average bill vs status quo – 2020 (£/customer)



4.63. Under socialised charging increases in customer bills would be highest in Scotland and the north (which currently benefit from low locational demand charges), areas with the highest incidence of fuel poverty currently. Consumer bill increases under improved ICRP are more consistent, except in Scotland where they are lower once the HVDC "bootstraps" have been commissioned (phase one of the Eastern HVDC link is anticipated to commission in 2018/19 under the improved ICRP approach).

Policy sensitivities

4.64. As noted above, two policy variants were modelled. The quantitative results are set out in Appendix 2. The key results are briefly summarised below.

- The improved ICRP variant further lowers tariffs for generators in the north of Scotland relative to the base case (and status quo), but does not have a significant impact on renewable deployment or accelerate commissioning of the HVDC links compared to improved ICRP.

- The socialised variant delivers some benefits over the base case socialised approach, but costs to consumers still rise by £4.8bn, or £8 per annum for the average domestic customer relative to the status quo by 2020.

5. Wider sustainability assessment

Question box

Question 1: Do respondents consider that we have appropriately identified and taken account of the key sustainability issues?

Question 2: Do you think there may be long term and strategic benefits associated with the development of HVDC technology, in particular the treatment of converter station costs for links that parallel the AC network, which Project TransmiT modelling has not fully considered because of the timeframe of the modelling (i.e. 2030) and the limited nature of the bootstrap options?

Question 3: Do you have any supporting evidence for a different treatment of the converter station costs for the planned bootstrap HVDC options?

Introduction

5.1. Our duties require us to have regard to the need to contribute to sustainable development. The quantitative analysis and results described in chapters 3 and 4 already take account of key sustainability issues. In particular, we have taken a long-term view and taken account of the potential impacts on depletable assets by:

- Modelling to 2030.
- Discounting costs and benefits using the Social Time Preference Rate of 3.5% real, as recommended by HM Treasury[40].
- Ensuring that all options deliver the 2020 renewable energy target and are consistent with the UK government's broader decarbonisation goals.

5.2. We have also taken account of the benefits of 'learning by doing' by including exogenous learning rate assumptions in the modelling (for example assuming a learning rate of 12% for offshore wind) and by including technology specific limits on the overall and annual build of new generation to proxy the impact of supply chain constraints.

5.3. This chapter reviews wider sustainability issues not included in our modelling. We have not identified any factors that point decisively to one charging approach or another, although improved ICRP would appear to be more consistent with the direction of travel of European policy. We are of the initial view that more consideration should be given to the treatment of HVDC converter costs and that if

[40] http://www.hm-treasury.gov.uk/d/green_book_complete.pdf

changes to TNUoS charging are appropriate that any proposals take into account long-term and strategic sustainability issues.

HVDC benefits from greater "learning by doing"

5.4. The cost of new technology can, at the outset, be high and this can limit its uptake, even though with sufficient deployment and volume it might become more cost effective. This is a particular challenge if the technology is essential to unlocking other strategic benefits.

5.5. HVDC technology, and the treatment of converter station costs, may be an example of this. Our modelling work identifies seven potential HVDC transmission reinforcement projects totalling 12.6GW. The modelling indicates that under status quo four of these projects (8GW) are commissioned before 2030, whereas all but one (Wylfa-Pembroke) are commissioned under both the alternative charging approaches, although with slightly earlier commissioning dates for improved ICRP.

5.6. However, our model may be failing to capture fully the long-term strategic benefits associated with the development of HVDC technology. This could be because the time horizon of the modelling exercise is too short to realise the impact of long-term learning rates and because of the limited nature of the planned bootstrap options considered.

5.7. Treatment of HVDC was discussed by the WG, with members recognising the benefits to generators of removing the costs of HVDC converter stations (for parallel links only) from the expansion factor calculation, thereby reducing the effect on locational tariffs. The impact of this was modelled as a variant of improved ICRP, which demonstrated no impact on HVDC deployment but did increase power sector costs and consumer bills relative to the improved ICRP base case.[41]

5.8. We recognise that this is an area where there is still a lot of scope for technological innovation and cost reduction. It is possible that the development of this technology could deliver additional benefits over the long term which might help unlock valuable wind resources in peripheral areas, and that the scale of this long term benefit might justify greater support in the short term.

5.9. However, support for HVDC technology through the TNUoS charging mechanism is only one possible option, and one that risks undermining locational charging signals which do give incentives for a more efficient system, with both economic and environmental benefits. Alternatives would be to rely on explicit external support (similar to the Renewables Obligation or CfD's) and to recognise the potential for a proportion of the construction costs of the transmission reinforcement

[41] We have not considered offshore DC transmission disaggregated in this way, which could be expected to increase assessed costs (lower NPV) but may also increase strategic benefits associated with learning, pathways and optionality. However, as noted in chapter 3, the treatment of HVDC converter station costs under the offshore transmission regime is not within the scope of the TNUoS SCR.

necessary to connect generation technology at remote locations to be incentivised under the price control.

5.10. We consider it important to guard against a charging approach which could potentially discourage the uptake of HVDC technology. We therefore consider that the treatment of the converter station costs for the planned bootstrap HVDC options should remain open and we invite feedback and supporting evidence on the appropriate approach as part of this consultation process.

Policy lock-in

5.11. All of the charging options we are considering are consistent with deployment of significant amounts of onshore and offshore renewable generation. Socialised charging would result in most offshore generation, which whilst avoiding the issues of planning constraints and public objections would present more supply chain and technical capability issues than onshore wind. Nonetheless, none of the charging approaches risk locking the UK in to unsustainable patterns of generation.

5.12. Possibly more important is the risk of regulatory or policy lock-in. In particular, it is important to avoid locking transmission charging into an approach which is inconsistent with the direction of travel of the European Target Model and the potential requirement for market splitting. The full implications of market splitting are unclear, but it will result in locational charging for energy and/or transmission in some form. Arguably the status quo and improved ICRP approaches are more consistent with this direction of travel than socialised charging, which would result in completely non-locational charging for energy and transmission.

Diversity

5.13. We have assessed the impact of the different charging approaches on the technology and geographical diversity of the generation sector using the Shannon-Wiener index[42]. All show reasonable levels of diversity, with the status quo scoring highest on technological diversity (1.91 by 2030) and socialised highest on geographical diversity (1.99 by 2030) and overall (2.91 by 2030). Improved ICRP is mid-range for both categories and ranks second overall (2.72 by 2030).

Optionality

5.14. Given the resources expended by both the regulator and key industry players throughout the Project TransmiT process (e.g. responding to consultations, attending stakeholder events, participation in the Technical Working Group), retention of the

[42] Shannon-Wiener index (D) is calculated as $D=-\Sigma(p_i \ln p_i)$ where p is proportion of a system accounted for by each participant and ln in the natural logarithm. A result below 1 indicates that the system is highly dependent on a single source (likely to around 70% depending on the number of participants). A system with a diversity value above 2 will include a substantial number of participants and a significant contribution from each.

status quo may rule out further examination of improvements to the existing charging methodology in the near term (i.e. there is an opportunity cost associated with a 'no change' recommendation). However, this is not in itself a reason to introduce change.

5.15. The socialised option arguably presents more constraints on optionality because of the nature of transmission reinforcement it requires. Much of the new network capacity developed to accommodate its large quantity of offshore wind would provide fewer options in terms of infrastructure sharing compared to onshore wind. This would potentially narrow future options for connecting new generation into existing capacity.

6. Ofgem's initial views

Assessment

6.1. The objective of Project TransmiT is to ensure that arrangements are in place to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers. We have therefore assessed the different transmission charging options against three primary criteria:

i) Deployment of low carbon generation across GB and the impact on achieving the UK government's renewable energy target of 30% of generation from renewable sources by 2020.

ii) Quality and security of supply across GB.

iii) Overall cost of the system as a whole and customer bill impacts.

6.2. We have also considered the strategic and sustainability implications of the different options, as well as a number of practical issues.

Deployment of low carbon generation

6.3. Transmission charging alone cannot deliver the government's environmental targets. Subsidy from government is also required. Our analysis assumes that DECC's EMR work sets support for low carbon generation to ensure that the binding 2020 renewable target is met under any charging approach, which DECC has confirmed is an appropriate assumption for the purposes of our modelling. However, we have also established that all three charging approaches are consistent with delivery of the 2020 target even if levels of support are maintained at levels equivalent to those in the recently announced Renewables Obligation re-banding review. Socialised charging does, however, reduce the risk of failing to meet the 2020 target for any given level of low carbon support.

Security of supply

6.4. We have assessed the impact of each charging approach on de-rated capacity margins, assuming that a simplified form of capacity mechanism is in place, in line with government proposals. Capacity margins remain at acceptable levels in all cases and the modelling results do not suggest any specific locational security of supply issues under these margins and with the transmission reinforcements modelled.

Overall costs and customer bill impacts

6.5. Differences between the alternative charging approaches are more marked for overall costs and customer bill impacts. The stage 2 analysis (i.e. assuming that DECC adjusts support for low carbon generation so that the 2020 target is met in all cases) suggests that a socialised approach has net costs of £2.8bn to 2020 compared to status quo, pushing up consumer bills by £6.9bn, equivalent to £11 a year on average, and exacerbating existing regional patterns of fuel poverty.

6.6. The socialised variant (where wider costs only are socialised) delivers some benefits over the 'full' socialised approach, but costs to consumers still rise by £4.8bn, or £8 a year relative to the status quo.

6.7. Improved ICRP delivers overall cost savings of £122m to 2020 (made up of small cost increases totalling £58m NPV to 2014 followed by cost savings between 2015 and 2020 of £180m). Customer bills would be largely unaffected in the early years but would rise after 2017, totalling £0.9bn in the period to 2020, equivalent to £1.50 a year on average. However, in all cases the impacts are small in the context of total costs and, unlike under socialisation, broadly regionally consistent.

6.8. The improved ICRP variant (where a proportion of the HVDC converter costs are socialised) makes generation in the north of Scotland more attractive relative to the base case but does not have a significant impact on renewable deployment or accelerate commissioning of the HVDC links. It does, however, further increase costs to consumers to £1.2bn, or £2 a year on average relative to status quo.

Other issues

Sustainability

6.9. All charging approaches meet the 2020 renewable generation target. However, stage 1 modelling indicates that socialised charging could be expected to result in the most renewable generation (hitting 36% of total demand in 2020 versus the target of 30%) for any given level of low carbon support, thereby potentially reducing the risk of not meeting the UK government's 2020 target.

6.10. We also note that the socialised approach has a lower trajectory of carbon intensity up to 2025 - a function of the higher renewables deployment, thereafter, the lower deployment of nuclear and CCS under this option leads to a higher carbon intensity than under the status quo or improved ICRP.

6.11. Our wider sustainability assessment does not point decisively to one charging approach or another, although it does highlight the potential long term benefits from alternative treatment of HVDC converter costs under improved ICRP.

Europe

6.12. Improved ICRP appears more consistent with the direction of travel of EU policy. Socialised charging may be at odds with this, raising the potential for significant costs for transitioning back and forth.

Practical issues

6.13. We have also considered a number of practical issues relating to the applicability of the charging approaches, including simplicity, transparency and compatibility. The key points to note are:

- Socialised charges are easy to understand, calculate and levy. Improved ICRP may be marginally more complex.
- Step changes to charging arrangements (ICRP to socialised) pose a greater risk of unintended consequences than incremental changes to well-understood arrangements (status quo to improved ICRP).

Our conclusions

6.14. Based on the evidence collected and our assessment of it, **our initial view, on which we are consulting, is that we should rule out socialised charging**. This is because:

- Although the socialised approach reduces the risk of not meeting the UK government's 2020 renewable generation target for any given level of low carbon support, it does so at disproportionate cost.
- Cost increases for consumers would not be equal throughout GB and would exacerbate existing regional patterns of fuel poverty. Average bills would rise most in north Scotland where fuel poverty is highest and least in London where fuel poverty is lowest.
- Socialising just the wider asset charges reduces costs and customer bill impacts compared to full socialisation, but they are still significantly higher than for the status quo and improved ICRP.
- It risks straying into areas of government policy around the degree of subsidy for low carbon generation, which could cause confusion.

6.15. If we do rule out socialised charging we consider it is important to reaffirm the principle of cost reflectivity in transmission charging. However, the choice between improved ICRP versus retaining the status quo is not clear cut.

6.16. Under improved ICRP society would benefit from a small reduction in power sector costs compared to status quo, customer bills would be largely unaffected in the early years and whilst they rise after 2017 the effects are small when measured against total costs. Notwithstanding this, we consider that improved ICRP better reflects the costs intermittent generators impose on the need for transmission investment and more accurately reflects the economic trade-off each Transmission Owner makes between expected constraint costs and the cost of new transmission reinforcements when planning investment activity. Improved ICRP would also appear to be more consistent with the direction of European policy and would represent a relatively low risk evolution of the existing approach.

Based on the evidence collected and our assessment of the potential options for change, our initial view therefore is that improved ICRP is the right direction for transmission charging arrangements.

6.17. The work of the technical working group and our analysis suggests that we can be confident about the approach to some of the elements of improved ICRP, but less confident in other areas. Where we are less confident and we believe further work is required, we expect this to be carried out by the CUSC Modification Panel as part of any CUSC modification process. Specifically:

- Our view is that the treatment of islands that, over time, become connected to the wider transmission system should be as we have modelled for improved ICRP.
- We do not think it is necessary to alter the G:D split at this stage. However, NGET should keep the G:D split under review and make proposals for change as and when necessary through the normal modification process.
- Our view is that the broad approach to reflecting the different characteristics of generators modelled in improved ICRP (dual backgrounds with a peak security and year round wider charge) is appropriate, but that more work is needed on exactly how the year round charge is calculated and how it should be levied. This work should build on the work in Project TransmiT to date.
- We recognise there are arguments for and against the different options for dealing with HVDC "bootstrap" converter costs, including the possibility of greater uptake and higher learning rates for this technology if these costs are socialised. Industry should consider this further and advise accordingly.
- In addition, we think it would be helpful to be clear to NGET that it should take account of potential long-term and strategic sustainability benefits when reviewing its charging methodology in future, alongside power sector and consumer costs.

7. Next steps

7.1. This consultation seeks views on the charging options discussed, their impacts and our initial views on the way forward.

7.2. ***Responses to our consultation should be submitted to us by 14 February 2012.*** All non-confidential responses will be published on our website.

7.3. We intend to hold a stakeholder event during the consultation period, to provide an opportunity for stakeholders more widely to comment on the outcomes of the modelling work and our initial views on which we are consulting. The details of this event will be communicated in early January 2012.

7.4. More detail on the modelling approach is available from Redpoint's report. Additional numerical results of the modelling are included in an associated Excel file, published alongside the Redpoint report.

7.5. We also propose to hold an open session to allow Redpoint to demonstrate the analytical model. This will provide an opportunity for stakeholders to comment on the detail of the modelling work and the opportunity to receive a demonstration on the operation of the model. This demonstration session will take place during the consultation period. The details of this event will be communicated in early January 2012. ***We invite expressions of interest from stakeholders with relevant technical expertise to participate in the session. Please email your expression of interest to Project.TransmiT@ofgem.gov.uk by Wednesday 11 January 2012.***

7.6. To ensure that the modelling demonstration session is productive, we think it is important that a broad range of stakeholder interests are represented. However, due to the technical nature of the model, attendance at the session will be limited. Ideally, therefore, participants will be able to represent groups of stakeholders with common interests, rather than individual organisations. We will seek to accommodate all requests.

7.7. Subject to, amongst other things, responses to this consultation, we currently expect to publish our final recommendations in spring 2012. Should our final recommendations identify a change, we will issue a direction to NGET to bring forward an appropriate modification to the TNUoS charging methodology. Where there is a case for reform, we urge stakeholders to implement any appropriate changes as quickly as practicable after we issue our final recommendations. However, following the recent Code Governance Review, industry is responsible for deciding the manner and timing of the process to develop a modification proposal.

7.8. Ultimately, our role is to approve (or reject) modification proposals to the TNUoS charging methodology developed by NGET and industry. The Authority will only make a final decision on the transmission charging methodology when it approves or rejects any forthcoming modification proposal.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by midday Tuesday, 14 February 2012 and should be emailed to Project.TransmiT@ofgem.gov.uk or sent to:

Anthony Mungall
Electricity Transmission Team
Ofgem
3rd Floor
Cornerstone
107 West Regent Street
Glasgow
G2 2BA

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Following responses to this consultation, we currently expect to issue our final recommendations in spring 2012. Any questions on this document should, in the first instance, be directed to Anthony Mungall (Anthony.mungall@ofgem.gov.uk, tel: 0141 331 6010).

CHAPTER: Four

Question 1: Do respondents consider that we have appropriately identified and where possible quantified the impacts of the Project TransmiT options?

Question 2: Do respondents consider that there are additional impacts which we should take into account in the decision making process and, if so, what are these?

Question 3: Do respondents consider that we have appropriately identified the potential interactions of the Project TransmiT options?

Question 4: Do respondents consider that we have appropriately identified the likely impacts and consequences of these interactions?

CHAPTER: Five

Question 1: Do respondents consider that we have appropriately identified and taken account of the key sustainability issues?

Question 2: Do you think there may be long term and strategic benefits associated with the development of HVDC technology, in particular the treatment of converter station costs for links that parallel the AC network, which Project TransmiT modelling has not fully considered because of the timeframe of the modelling (i.e. 2030) and the limited nature of the bootstrap options?

Question 3: Do you have any supporting evidence for a different treatment of the converter station costs for the planned bootstrap HVDC options?

Appendix 2 – Policy sensitivities

1.1. Two policy variants were modelled. These were:

- **Improved ICRP**: the removal of all converter station costs of applicable HVDC links that run parallel to the onshore AC network (i.e. 'bootstraps') from the expansion factor calculation (a proportion would be recovered from the residual element of TNUoS).[43]

- **Socialised**: The retention of local asset charges in the generation TNUoS calculation (only the wider tariff would be uniform).

1.2. Results for these policy sensitivities are based on Stage 2 modelling.

1.3. In addition two input assumption scenarios were modelled. These were:

- An **RO-banding sensitivity** was constructed after the launch of the Government's consultation of revised Renewables Obligation banding levels. In response to stakeholder feedback, it was considered important to rerun the Stage 1 modelling under these assumptions to understand better the impact of the charging options assuming no further changes to existing levels of renewables support before 2020.[44]

- A **low gas price sensitivity** which is based on a 15% reduction in gas prices in all years, relative to the base case assumptions. This sensitivity was chosen in recognition of the uncertainty surrounding future gas price and the importance of coal and gas differentials in driving constraint costs.

Improved ICRP: HVDC variant

1.4. HVDC converters are a significant part of the cost of HVDC links. Removing them from the expansion factor calculation further compresses regional charges under improved ICRP charging (i.e. it further lowers tariffs for generators in the north of Scotland relative to the improved ICRP base case).

1.5. Tariffs produced by the model are slightly higher for zones that do not use HVDC links to export their power (due to an increase in the residual). Conversely, tariffs in zones that rely on HVDC links to export power (for example, charges in North

[43] Under this approach, the expansion factor (i.e. multiple of 400kV OHL costs) for HVDC links was to be re-calculated to exclude the costs of the converters, thereby reducing the effect on locational tariffs, but not completely removing the cost from the locational signal. Hence, wider tariffs do not increase to the same extent as they would under the base case Improved ICRP option.

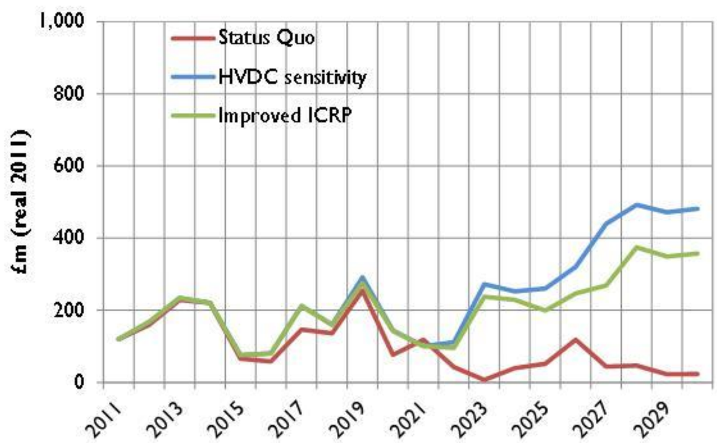
[44] In this sensitivity, the proposed RO bands contained in the UK government's consultation on the Renewables Obligation banding review, published in October 2011, have been applied until31 March 2017. From 1 April 2017, CfDs are set at levels equivalent to the remuneration under the RO (including power and LEC revenues). All results are based on imperfect foresight.

Scotland with build of Caithness-Moray link in 2020) do not increase to the same extent as they would under the base case improved ICRP option.

1.6. The change in tariffs does not have a significant impact on renewable deployment or accelerate commissioning of the HVDC links compared to improved ICRP. Relative to base case improved ICRP there is a small increase in build in offshore Scotland (additional 500 MW) and onshore North Scotland (additional 150 MW) by 2030, with slightly less build offshore in the Irish Sea (reduction of 575 MW).

1.7. Transmission constraint costs to 2020 are similar under the HVDC sensitivity as under base case improved ICRP. The increase in build of renewables in Scotland leads to higher constraint costs in the period after 2020. This movement is illustrated in the figure below.

Figure A1: Constraint costs: HVDC sensitivity



1.8. The CBA results to 2020 (set out in the tables below) are similar to base case improved ICRP, with little change in power sector costs relative to status quo. The slight change in tariffs does, however, further increase costs to consumers to £1.2bn, or ~£2 pa (instead of £0.9bn/£1.50 pa under the full approach) relative to status quo by 2020. The increase in consumer bills relative to improved ICRP is due to the pass through of higher transmission and constraint costs to consumers.

1.9. Results to 2030 show an increase in power sector costs and consumer bills relative to both status quo and base case improved ICRP.[45] More detail on the cost benefit analysis beyond 2020 is available in Redpoint's report.

[45] Note: negative numbers represent a cost decrease relative to the status quo. Positive numbers represent a cost increase. Hence, the cost benefit analysis suggests that the socialised base case results in a net increase in a power sector costs.

NPV 2012 to 2020 (at 3.5%) - £mn real	Improved ICRP variant	Improved ICRP base
Generation costs	-332	-313
Transmission costs	225	8
Constraint costs	183	171
Carbon costs	5	11
Total impact on power sector costs	**82**	**-122**

NPV 2012 to 2020 (at 3.5%) - £mn real	Improved ICRP variant	Improved ICRP base
Wholesale costs (inc BSUoS, losses & capacity payments)	1,640	1,436
Demand TNUoS charges	82	-98
Low carbon support	-458	-441
Total impact on consumer bills	**1,265**	**897**

Socialised: socialising wider charges only

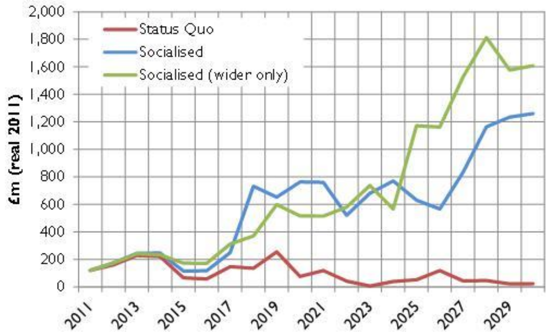
1.10. Retaining local charges leads to an increase in tariffs for those generators with large local tariffs, specifically offshore wind. Generators with low or zero local charges see a reduction in their total tariff, relative to full socialisation.

1.11. Under this variant, offshore wind is exposed to the same high local tariffs as under status quo, but the wider onshore element of the tariff would be the same wherever they connect. As a result, compared to 'full' socialisation there is less offshore wind in total and deployment moves from areas offshore of south and east England towards the Irish Sea and offshore Scotland, where sites are nearer to shore and local charges are lower. The result is a pattern of offshore wind build more similar to status quo.

1.12. In the period to 2020 both transmission and constraint costs for the socialised variant are lower than for 'full' socialisation, reflecting the reduction in remote offshore wind. After 2025 constraint costs under the sensitivity are higher, reflecting more generation from renewables in Scotland as a result of the additional onshore and offshore wind built their under the socialised (wider only) variant.

1.13. The CBA results to 2020 (set out in the tables below) show that the socialised variant delivers some benefits over the base case socialised approach. However, power sector costs still rise by £1.4bn to 2020 relative to status quo, and costs to consumers rise by £4.8bn, or £8 pa (instead of £6.9bn/£11 pa under the full approach).

Figure A2: Constraint costs: socialised sensitivity



NPV 2012 to 2020 (at 3.5%) - £mn real		
	Socialised variant	Socialised base
Generation costs	-313	-453
Transmission costs	559	1,569
Constraint costs	1,089	1,452
Carbon costs	101	201
Total impact on power sector costs	**1,424**	**2,769**

NPV 2012 to 2020 (at 3.5%) - £mn real		
	Socialised variant	Socialised base
Wholesale costs (inc BSUoS, losses & capacity payments)	5,286	7,433
Demand TNUoS charges	107	849
Low carbon support	-621	-1,406
Total impact on consumer bills	**4,772**	**6,876**

RO banding sensitivity

1.14. This sensitivity uses the latest proposed RO bands for the period 2013 to 2017 (as published in the RO banding consultation in October 2011) plus CfDs from 2017 that are structured to provide the same levels of support. The results are produced for Stage 1 modelling.

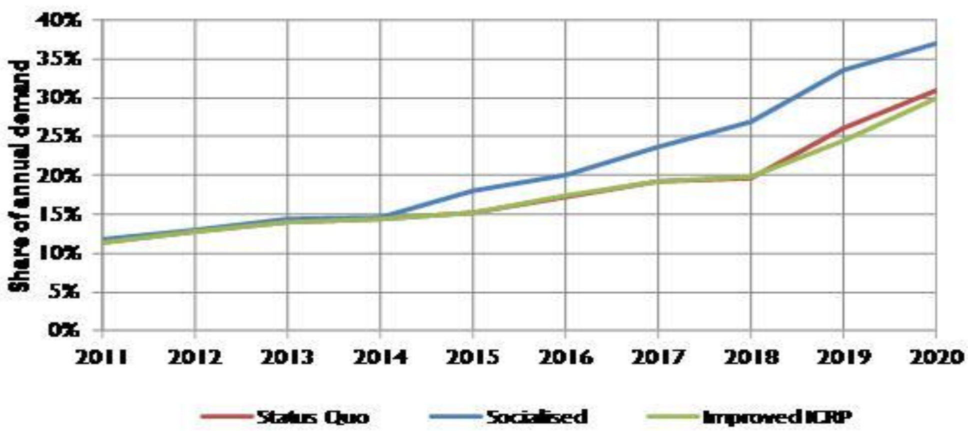
1.15. All three options meet the 2020 renewable targets (~30%), with socialised achieving a 37% renewable share by 2030.

1.16. Under status quo and improved ICRP, a significant proportion of the renewables that contribute to the target are built under CfDs once the RO has closed to new accreditations. The major difference between the options is that there is no offshore wind plant commissioned between 2013 and 2018 under status quo and improved ICRP, whereas there is rapid deployment under socialised base case.

1.17. Improved ICRP base case charging is no longer as effective in bringing forward renewable deployment in this sensitivity because all the available onshore wind projects in mainland GB are already built under status quo. There is also a slight delay in offshore wind build in regions with negative TNUoS and therefore less favourable tariffs under improved ICRP.

1.18. Socialised charging (base case) brings forward significant additional renewables (in particular offshore wind) because it removes the offshore local tariff, which for most projects is a significant cost.

Figure A3: Renewables generation: RO banding sensitivity



Low gas price sensitivity

1.19. The low gas price sensitivity reduces gas prices by 15% in all years. This has the effect of reversing coal and gas in the merit order to 2020. A similar effect could have been achieved by a sensitivity run that increased the carbon price.

1.20. The low gas price scenario leads to some changes which are consistent across the transmission charging options:

- Wholesale prices are lower across all three policy options
- Coal generators are less profitable and retire earlier across all three policy options
- Low carbon investment is insensitive to gas prices due to the CfDs (however payments under CfDs do increase significantly). Hence, there is very similar renewables deployment as in status quo.
- There is additional new CCGT investment
- Constraint costs are lower in the near term under this scenario, for two reasons:
    - More CCGTs are dispatched and these are generally located further south than coal generators, requiring fewer interventions by the system operator to relieve congestion
    - Bid offer spreads are set as a multiplier on the SRMC of each thermal generator, and so CCGT bid offer spreads decrease by 15%
- Socialised de-rated capacity margins are higher from 2020 due to additional CCGT build

1.21. The impact on power sector costs to 2020 is summarised below. For both improved ICRP and socialised reductions in generation cost are more than offset by higher transmission and constraint costs (and in the case of socialised, carbon costs too), resulting in broadly similar overall cost impacts.

1.22. The impact on consumer bills is more marked. Under improved ICRP bills rise by £2.1bn, equivalent to £3 a year. Under socialised renewable target are met with less low carbon support, but overall consumer bills still go up by £5.4bn, or £8 a year for an average domestic consumer.

NPV 2012 to 2020 (at 3.5%) - £mn real		
	Improved ICRP	**Socialised**
Generation costs	-302	-2,009
Transmission costs	299	1307
Constraint costs	316	697
Carbon costs	3	327
Total impact on power sector costs	**316**	**322**

NPV 2012 to 2020 (at 3.5%) - £mn real		
	Improved ICRP	**Socialised**
Wholesale costs (inc BSUoS, losses & capacity payments)	2,541	7,483
Demand TNUoS charges	98	751
Low carbon support	-526	-2,806
Total impact on consumer bills	**2,112**	**5,428**

Appendix 3 – Impact assessment

1.1. This impact assessment builds upon the discussion of impacts in the main body of this consultation document. The appendix should not be viewed as a standalone impact assessment – instead it should be read in conjunction with the remainder of this consultation. This document in its entirety forms our assessment of the impacts of the Project TransmiT options.

1.2. This impact assessment considers the following factors:

- Impact on consumers
- Impact on competition
- Impact on sustainable development
- Impact on health and safety
- Risks and unintended consequences
- Impact on trade between European Community Member States

Assessment[46]

1.3. In considering the implications of the Project TransmiT options, we have taken into account, amongst other things, the analysis undertaken by Redpoint Energy for Ofgem.

Impact on consumers

1.4. The Authority's principal objective is to protect the interests of existing and future consumers, wherever appropriate through the promotion of effective competition[47]. These interests are taken as a whole including interests in emissions

[46] The Authority must assess and make a decision on the Project TransmiT proposals within the prescribed framework of the SCR process. Ultimately, if it directs NGET to raise a modification proposal, the Authority's final decision on whether that proposal should be implemented will be based upon:
- whether the proposal better fulfils the achievement of the relevant objectives as compared with current arrangements, and
- whether the proposal is consistent with its wider statutory objectives and duties, including those under European law.

That final decision is taken in the light of a formal assessment by the modification panel.
In order not to encroach upon the modification panel's assessment of any potential modification proposal arising out of this SCR, the Authority does not consider that it is appropriate at this stage for it formally to assess the various TransmiT proposals against the relevant objectives in this Impact Assessment. This Impact Assessment instead is focussed on performance of the proposals against criteria derived from the Authority's wider statutory objectives and duties, in the normal way.
[47] Before deciding whether to promote competition, the Authority should consider whether consumer interests would be protected and whether there is any other approach that could carry out those functions which would better protect those interests.

reduction and security of supply and fulfilment of the Authority's objectives under Article 36 (a) to (h) of the Electricity Directive.

1.5. Customer bill impacts and security of supply impacts are both discussed in Chapter 4 (see paragraphs 4.51 to 6.63) and summarised in Chapter 6 (see paragraphs 6.5 to 6.8 and paragraph 6.4). Consumer interests in terms of emissions reduction are also discussed in Chapter 4 (see paragraphs 4.20 to 4.27) and summarised in Chapter 6 (see paragraph 6.3) but we provide further analysis of sustainability impacts later in this appendix.

Impact on competition

1.6. We consider that the options could impact on competition by:

- Altering the competitive balance in the market.
- Having a distributional impact on participants.
- Impacting on consistent and non-discriminatory treatment of users.
- Increasing regulatory uncertainty, leading to barriers to entry.
- Increasing the complexity of the charging methodology.

Market competition

1.7. The introduction of a new approach to transmission charging would alter, to some extent, the economics of generating electricity for sale in the wholesale market. Therefore it would impact on the terms on which generators compete against each other.

1.8. In general, the effect of the Improved ICRP approach is to 'compress' locational variations in generation TNUoS charges, particularly for intermittent renewables. Hence, zones which currently have high TNUoS charges, such as North Scotland, become relatively more attractive for locating plant and zones which currently have low, or negative TNUoS charges, such as South of England, become relatively less attractive. We think that improved ICRP would assists in creating a more level playing field on which generators would compete insofar as it would more accurately reflect the costs that different types of generators impose on the system.

1.9. There is no impact on demand TNUoS charges, other than as a consequence of different levels of Maximum Allowed Revenue (MAR), which may result from different patterns of investment in response to the changing price signals on the generation side.

1.10. The improved ICRP variant could have significant tariff benefits for generators on the exporting side of the bootstrap links in the north of Scotland, as it accentuates the compression of charges under improved ICRP charging.

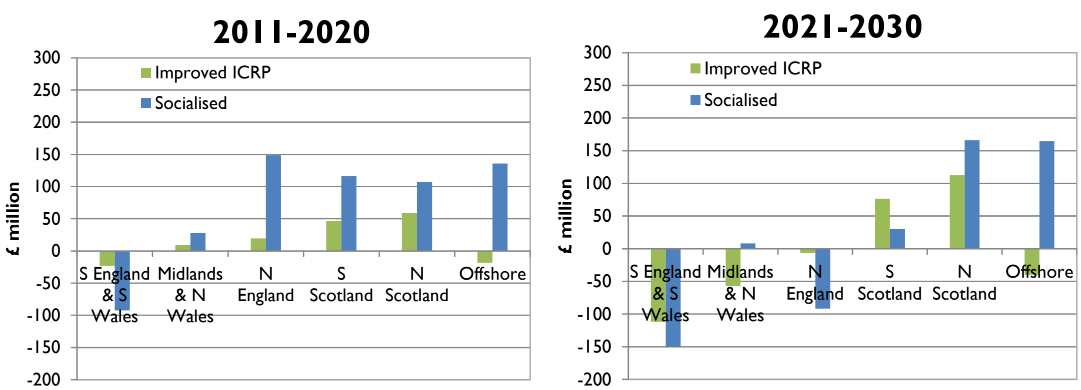
1.11. By making all charges uniform, the Socialised approach has a significant impact on locational price signals for generators. Offshore generators are the biggest beneficiaries of this approach. Companies would not need to take into account the associated transmission costs when deciding whether to invest or not. We think that this would affect the playing field on which generators would compete as they would not be exposed to the costs that they impose on the system. On the demand side, the current differences in demand TNUoS would be removed.

1.12. Modelling indicates that there would be a change to the balance of competition in the wholesale market to some extent. This is particularly the case under the Socialised approach, where there is tighter capacity margin and in the long term a larger change in the capacity mix. The modelling suggests that such an approach is likely to change the merit order more considerably than an improved ICRP (or its variant) approach.

1.13. For example, modelling indicates that improved ICRP, and its variant similarly, will result in more onshore wind capacity, less biomass and marginally less offshore wind than under status quo. Under Socialised charging it indicates significantly more offshore wind and less biomass than under either status quo or improved ICRP (or it's variant). Similar results are projected under the Socialisation variant, although this is shown to favour offshore wind closer to the shore than under Socialised.

1.14. For both improved ICRP and socialisation, generators on the whole are estimated to make higher profits between 2011 and 2020 as a consequence of higher wholesale prices, these are higher for socialisation than improved ICRP as shown in the figure below. During the period 2021 to 2030, total generator profits are similar across the three charging options.

Figure A4: Average annual change in total generator profits, relative to Status Quo



1.15. Both improved ICRP and socialised relatively favour generators in high TNUoS charging zones under status quo although to differing degrees as shown. Specifically, under improved ICRP generator profits are higher in Scotland, at the expense of generators in south England, the Midlands and Wales. Socialised charging increases overall generator profits in Scotland and offshore, but profits are lower in South England and Wales and (after 2021) in North England.

Distributional impacts

1.16. Distributional impacts are discussed as part of Chapter 4 and summarised in Chapter 6 (see paragraphs 6.5 to 6.8).

Discrimination

1.17. The Authority is mindful of the possibility that various elements of the proposals under consideration might be argued to result in discrimination, whether through treating like cases differently or treating different cases alike, in either case without objective justification.

1.18. First, to the extent that proposals promote or further cost reflectivity, they can be said to reduce the risk of an element of possibly discriminatory treatment in the current system by increasing the extent to which a relevant difference between customers – the costs that they impose on the network – results in differential treatment as between those customers. It could be argued, for instance, that the current charging methodology results in discrimination to the extent that it fails to reflect, by not taking into account load factors , the lower costs imposed by intermittent generation

1.19. On the other hand, it can be argued in favour of the socialised options and the socialised variant that they remove differential treatment based on location, which treatment tends to impose higher costs on renewable generation (because it is typically sited further from areas of high population density and demand). We think it is appropriate that status quo, improved ICRP and improved ICRP variant distinguish between generators based on location, with the latter two including the type of generation as a distinguishing aspect. These ICRP based proposals provide for differential treatment of various generators insofar as some will be allocated higher tariffs than others. It can, however, equally be argued that *not* reflecting in charges relevant differences in the costs imposed on the network (as certain costs vary in accordance with distance) would itself amount to discriminatory treatment.

1.20. The dominant issue is whether the differences in treatment under each proposal are capable of objective justification, which turns on the matters discussed elsewhere in the consultation document, including as to overall costs and benefits.

Increasing regulatory uncertainty, leading to barriers to entry

1.21. We consider that consumers' interests are not served by requiring industry to incur unnecessary costs of change, and effective competition is best furthered through a high degree of regulatory certainty against the background of which industry players can make efficient long-term choices.

1.22. However, the need for change was underlined by responses to our September 2010 call for evidence. Our work has focused on addressing these issues and concerns directly and hence our initial view is that the status quo may lead to a barrier to entry for intermittent generators whose impact on the network and hence the investment costs are not reflected by the transmission charging tariff they receive.

1.23. As such, a move to an improved transmission charging regime is likely to increase regulatory certainty and hence remove barriers to entry. Our initial view is that it would be appropriate to direct NGET to raise the improved ICRP proposal as part of the CUSC process for industry to consider and assess this in more detail.

Increasing the complexity of the charging methodology

1.24. It could be argued that socialised charges are easy to understand, calculate and levy (although the Socialisation variant is relatively more complex) whereas improved ICRP may be marginally more complex.

1.25. We must weigh any increased complexity of the charging structure against the overall benefit.

Overall

1.26. Overall our initial view is that the improved ICRP option is likely to better facilitate competition than both status quo and Socialised since it is more cost reflective and to that extent may reduce some discrimination within the charging arrangements. In addition, improved ICRP has a lower re-distributional effect relative to socialisation. Whilst the improved ICRP option is more complex than the status quo and socialisation options it has a higher overall benefit in terms of cost to the power sector although a negative impact on consumer bills relative to the status quo (note the socialisation option is considerably more negative). These reasons contribute to our initial view is that the improved ICRP proposal is worth considering further as part of the CUSC modification process.

Impact on sustainable development

1.27. There are several aspects of sustainable development to be considered. Chapters 4 and 5 of this consultation cover a range of sustainability impacts. In this section we add further assessment of the following issues:

- Managing the transition to a low carbon economy
- Promoting energy savings
- Eradicating fuel poverty and protecting vulnerable customers
- Ensuring a secure and reliable gas and electricity supply
- Supporting improved environmental performance.

Managing the transition to a low carbon economy

1.28. In addition to the relative attainment of the 2020 government renewable generation targets mentioned in the consumer section above, we should also consider the speed of deployment of renewables and other forms of low carbon generation assuming the same level of low carbon support across the different TransmiT options.

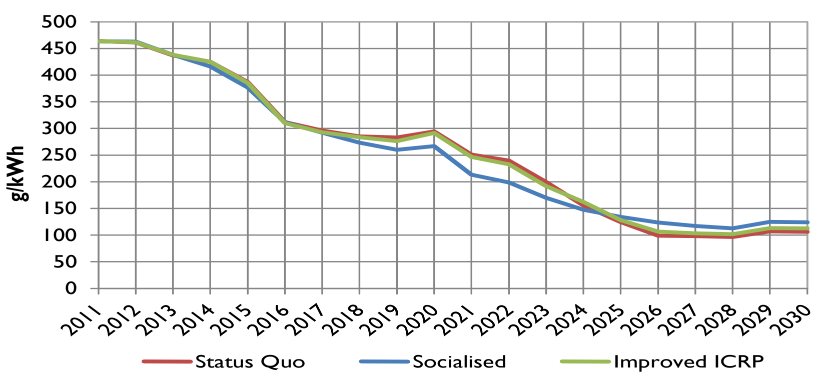
1.29. Both improved ICRP and socialisation options take account of the features of intermittent generation and hence would reflect developments of the transmission licensees' transmission businesses.

1.30. Our assessment of the Project TransmiT options included an assessment of the deployment of low carbon generation across GB and impact on achieving the government's Renewable Energy Strategy target of 30% of generation from renewable by 2020. All charging approaches are capable of meeting the 2020 renewable generation target. Stage 1 modelling indicates that socialised charging could be expected to result in the most renewable generation (hitting 36% of total demand in 2020 versus the target of 30% if current levels of subsidy are applied, and the 30% target in 2018), thereby potentially reducing the risk of not meeting the UK government's 2020 target for any given level of low carbon support. However, Government has indicated that it will take into account the effect on low carbon deployment of the result of the TransmiT project in setting subsidy levels. We therefore expect such subsidies to be "flexed" in the light of adoption of any of the options so that the target is met in 2020 but not before.

1.31. In general it appears that the socialised option favours increased renewable deployment especially offshore and onshore wind. A further significant difference in the capacity mix under Socialised is the lower volume of nuclear capacity by 2030 and lower CCS capacity.

1.32. This suggests that there could be benefit in the socialised approach as measured by the speed of renewables deployment relative to a charging approach based on the current ICRP methodology, assuming that the level of low carbon support is fixed.

Figure A5: Carbon intensity of generation as produced by the Redpoint model



1.33. However, as figure 2 above shows although the socialised approach has a lower trajectory of carbon intensity up to 2025 - a function of the higher renewables deployment, thereafter, the lower deployment of nuclear and CCS under this option leads to a higher carbon intensity than under status quo or improved ICRP.

1.34. Thus in the short to medium term the Socialised approach manages the transition to a low carbon economy better than an ICRP type proposal but in the long term this trend reverses.

Promoting energy savings

1.35. In general transmission losses are greater the greater the average distance that power needs to be transported to reach the demand centres. Hence, transmission losses are greater under improved ICRP than status quo, with the higher deployment of onshore wind in Scotland, and significantly greater under Socialised driven to a large part by the greater proportion of offshore wind further from shore.

Eradicating fuel poverty and protecting vulnerable customers

1.36. This is discussed as part of Chapter 4 (see paragraphs 4.59 to 4.63) and summarised in Chapter 6 (see paragraphs 6.5 to 6.8). In summary our initial view is that the socialised options may exacerbate existing regional patterns of fuel poverty. Although improved ICRP has a smaller but still negative effect on consumer bills, it is less regionally focussed.

Ensuring a secure and reliable gas and electricity supply

1.37. This issue is discussed in Chapter 4 of this consultation (see paragraphs 4.29 to 4.31) and summarised in Chapter 6 (see paragraph 6.4). In summary our initial view is that security of supply implications are similar across all modelled options.

Supporting improved environmental performance

1.38. To the extent that the proposal would lead to more efficient use of the transmission system, we consider that this would lead to more efficient investment and operation decisions by the TOs. Given the carbon footprint and impact on visual amenity of the transmission system, this should ultimately lead to a better trade-off between all aspects of transmission and hence better environmental performance.

1.39. For the Project TransmiT options, the material impact is likely to be low.

Impact on health and safety

1.40. We have not identified any health and safety implications related to the Project TransmiT options.

Risks and unintended consequences

1.41. We consider that any risks or unintended consequences resulting from the Project TransmiT options have been identified elsewhere in this consultation. For example, we discuss risks to security of supply and impacts on fuel poverty which could be impacted under the modelled options. However, we would welcome any parties views on other potential risks and unintended consequences associated with the Project TransmiT options that we have not identified.

Impact on trade between European Community Member States

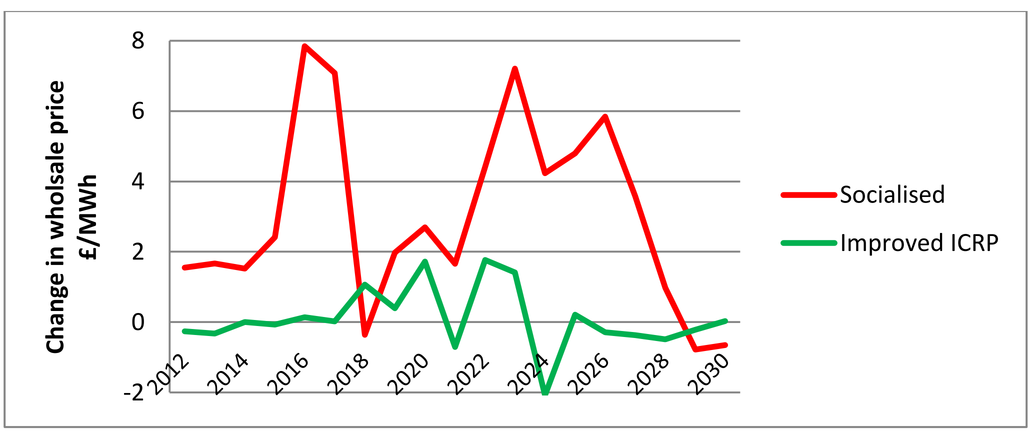
1.42. Since 2010, interconnectors and importers have not paid TNUoS charges, and so their transmission charges will not be affected by the Project TransmiT options.

1.43. The impact of the three base case options considered on cross-border trade is split between the following short-term and long-term effects.

- **Short-term:** trade between interconnected markets is driven by the wholesale market price differential, with electricity flowing from the low-price to the high-price market. The impact of the three options considered on the GB wholesale price has been modelled. Over the 20-year period considered, the average difference between the three options in terms of their impact on the GB wholesale market price is between £3/MWh and £1/MWh.

- As you can see in figure A6 below, the modelled price wholesale price changes under Project TransmiT indicate that prices under the Socialised option generally increases by more than under improved ICRP where there are often decreases in wholesale price. The price changes are limited but on average, as GB is increasingly coupled and interconnected with other markets, if the GB wholesale price increases this will likely reduce export/increase import and if GB wholesale price decreases this will likely increase export/reduce import.

Figure A6: Change in wholesale price relative to the status quo



- **Long-term:** the options will impact on generator investment decisions, whether to locate new generation in GB or in interconnected markets, which in turn will have an impact on the transmission network flows and constraint costs. Project TransmiT has not considered these impacts.

Appendix 4 – Overview of WG discussion

1.1. Section 11 of the Report of the Technical Working Group summarises the WG's recommendations for the technical detail of the different charging approaches, highlighting where consensus was reached and where options remain. The summary tables from that report, setting out the areas of consensus and areas where Ofgem were required to make a decision, are reproduced below.

Status Quo (ICRP extended to 2030)	
Theme	**Outcome**
1	- no change
2	- no change
3	- no change - noted that some island connections could be classed as wider for charging purposes and would therefore have a security factor of 1.8
4	- model HVDC links that parallel the onshore network as an equivalent AC circuit by: i) determining impedance from an HVDC power flow calculated as the average of a ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses ii) **No consensus** on calculating expansion factor for the HVDC link; choice of either: a) excluding convertor costs or b) including all costs
5	- no change
6	- move from a G/D revenue collection split of 27/73 to 15/85 from 2015

Improved ICRP	
Theme	**Outcome**
1	- Dual background approach to the Transport Model used in calculating locational differentials (Peak Security and Year Round backgrounds) - Background scaling factors for plant types consistent with NETS SQSS proposals under GSR009 - The use of a two part tariff commensurate with the dual backgrounds - **No consensus** on plant contributing to tariff elements; choice of: i) Intermittent plant only contributes to Year Round element; or ii) All plant contribute to both Peak Security and Year Round element - **No consensus** on tariff calculation for Year Round element; choice of: i) TEC only ii) TEC x specific historic (ex ante) load factor iii) TEC x generic load factor for plant type iv) TEC x specific forecast load factor (with reconciliation) v) TEC x ex-post MWh
2	- no change to zoning criteria or local/wider boundary definition

3	- no change - for island connections that would be classed as wider for charging purposes and that have significant sections of single circuit (i.e. islands with single circuit sub-sea connections) a security factor of 1.0 will be applied to that section.[48]
4	- focus on HVDC link technology only - model HVDC links that parallel the onshore network as an equivalent AC circuit by: i) Determining impedance from an HVDC power flow calculated as the average of a ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses ii) **No consensus** on calculating expansion factor for the HVDC link; choice of either: a) excluding convertor costs or b) including all costs
5	- no change
6	- move from a G/D revenue collection split of 27/73 to 15/85 from 2015

Theme	Socialised Outcome
1	- **no consensus** on reflecting user characteristics; choice of allocating charges based on: i) MW or ii) MWh
2	- **no consensus** on differentiation of costs; choice of: i) maintain existing local/wider boundary ii) remove local/wider boundary and socialise all costs iii) continue to calculate an ICRP based demand charge iv) charge demand on the same basis as generation (i.e. socialised)
3	- only relevant if maintaining local wider boundary - no change for local if maintaining local/wider boundary
4	- not relevant for a postage stamp model
5	- only relevant if maintaining local wider boundary - no change for local if maintaining local/wider boundary
6	- move from a G/D revenue collection split of 27/73 to 15/85 from 2015

1.2. Further detail on the modelling approach we instructed Redpoint to adopt for each charging option is set out below.

Status quo

1.3. A specific challenge that the WG faced with the development of the technical detail associated with the status quo approach to be modelled was the proposed length of the modelling exercise - developed to consider a time horizon that extends to 2020, and then 2030. It became clear that there are some areas of planned network development where the treatment of a particular technology or a category of user is not currently codified (i.e. treatment is not considered in the current ICRP methodology). Therefore clearly establishing the 'baseline' was problematic.

[48] The methodology will reflect this in the zonal tariff calculation by modifying the expansion factor applicable to this section of single sub sea section of the island connection by dividing the expansion factor value for the single cable link by the average level of security across the main MITS system (currently 1.8). This will produce a zonal tariff reflective of the specific security characteristics of the island connection and the single sub sea link included as part of the wide network.

1.4. Consequently, one of the decisions made by the WG was whether to treat areas of predictable development the same for both the current ICRP and improved ICRP or devise alternative arrangements for each modelling approach.

1.5. Some members of the WG were of the opinion that the status quo 'baseline' should simply reflect the current scope and text of the TNUoS methodology, and for this to be extended across the modelling period. In areas where the methodology is silent their preference was for the modelling exercise to produce no input to the production of analytical results. These areas would instead be reflected in the improved ICRP modelling approach. Another view put forward was that, in the absence of formal methodology framework, the modelling exercise should make some simplifying assumptions where treatment is not currently codified and where the particular treatment has been highlighted as an area of immediate concern to be addressed as part of the SCR process by respondents.

1.6. We were of the opinion that the purpose of the modelling is to enable Redpoint to conduct a comparable modelling exercise over the full modelling horizon. To meet this aim we considered it necessary to make some simplifying assumptions relating to areas of 'predictable development' where enough stable information is available to predict with a degree of certainty that it is relevant to the practical application of the charging arrangements (such as the bootstrap HVDC projects identified by the ENSG work). This category can also apply areas of the current regulatory framework where continued compliance of the charging methodology arrangements is required (e.g. the legally binding requirement to comply with the EU Tariffication Guidelines arising from the Regulation on Cross Border Electricity Exchanges[49]).

1.7. This approach is based on the view that it is sensible to assume that, consistent with NGET's licence obligation to make modifications to the use of system charging methodology so as better to meet the relevant objectives, the TNUoS methodology would be extended to take account properly of the developments in the transmission licensees' transmission businesses. Hence, the modelling exercise was formulated to make some simplifying assumptions where treatment is not currently codified and where the particular treatment has been highlighted as an area of immediate concern by respondents and/or areas of predictable development.

1.8. Under the status quo 'baseline' approach, it was therefore necessary to make decisions in relation to three specific themes:

- **Treatment of islands**: the current TNUoS methodology does not consider the treatment of transmission links to island users. In particular, the manner in which an appropriate charging signal will be provided to users to reflect the level of security provision associated with an economic connection design (theme 3)[50] is not considered.

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[49] These guidelines require that the value of the 'annual national average G' within Great Britain, Republic of Ireland and Northern Ireland should not exceed a value of €2.5/MWh. Currently GB generators contribute approximately €1.5/MWh.

[50] It was noted that, under the current MITS boundary criterion, if the planned reinforcements linking the Scottish islands to the mainland transmission network were to proceed the transmission link between local substation of connection located on the island and the first MITS substation located on the mainland could form part of the wider transmission network. This would likely lead to the creation of an additional generation TNUoS zone for each link due to the significant cost of sub sea cable connections. While this

- **Bootstrap HVDC links**: the current TNUoS methodology does not recognise the treatment of integrated HVDC links that parallel the main onshore AC network (or the expectation of network technology change in general) (theme 4) and

- **Europe**: based on the technical advice of NGET in its role as System Operator (SO) for the NETS, it will be necessary to change the G:D split to remain compliant with European tariffication legislation in the next few years (theme 6).

1.9. It was necessary to make decisions in relation to the same three themes, amongst other things, under an improved ICRP charging approach.

1.10. The rationale underpinning the development of simplifying assumptions applicable to the status quo 'baseline' modelling approach was that the modelling approach should reflect, where practical and appropriate:

- a straight extrapolation of what the Connection and Use of System Code (CUSC) currently defines as 'wider' transmission infrastructure and/or
- an extension of the principles behind the regulation of the current TNUoS electricity transmission network to facilitate areas not currently included in the methodology and charging model.

1.11. The key parameters of the status quo charging approach we asked Redpoint to model are set out below.

Theme	**Status quo**
1	• No change from the existing TNUoS methodology
2	• No change from the existing TNUoS methodology
3	• *Sub-sea cable linking a substation located on a Scottish island group to a MITS substation on the mainland*: Noting the WG agreement that the Scottish islands are part of the geographic area of the existing transmission and distribution licences, we instructed Redpoint to adopt an approach that will: o Retain a network average security factor (currently 1.8) in the TNUoS tariff calculation when circuits meet the wider MITS boundary criteria.[51] o Retain a specific local security factor (at a value of 1.0) in the TNUoS tariff calculation for island links connected to the onshore network that do not meet the wider MITS boundary criteria.[52]
4	• We instructed Redpoint to determine impedance from an HVDC power flow as the average of a ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses. This reflects the consensus

would result in identical locational differentials between the island and mainland connection points determined under a local circuit charge, the tariff calculation would not be multiplied by a specific local security factor (i.e. 1.0), but the global security factor (currently 1.8) applied to all wider infrastructure assets.

[51] As defined in 14.15.54-6 of NGET's Methodology Statement.

[52] As defined in 14.15.57 of NGET's Methodology Statement.

	approach put forward by the WG. • The WG was unable to agree whether HVDC converter station costs should be included in the calculation of the expansion factor for both links that parallel the onshore AC transmission network and radial links used for offshore Transmission (and proposed links to the Scottish islands). We instructed Redpoint to include all costs (cable and converters at each end of the link) in the calculation. This was applied to all planned HVDC reinforcements, both parallel and radial links. This reflects the position previously consulted upon and endorsed by the Authority under GB ECM-08 and ECM-24[53] and reflected in 14.15.50 in NGET's Methodology Statement.
5	• No change from the existing TNUoS methodology
6	• Change the G:D split from 2015/16 from 27:73 to 15:85 in order to remain compliant with the European Tariffication Guidelines. This approach will be applied across all three charging approaches.

Improved ICRP

1.12. Improved ICRP charging aims to improve (hence *improved* ICRP) the accuracy of cost targeting by taking into account the fact that differences in the characteristics of generation drive different investment costs on the transmission network.

1.13. The WG considered the technical detail of a potential improved ICRP modelling approach based on the six themes noted above.

1.14. Similar to the status quo modelling, debate amongst WG members about what would constitute an Improved ICRP model. Reflecting the status quo 'baseline' discussion (noted above), the WG discussion noted that to inform Redpoint's modelling exercise it was necessary to make decisions in the following areas (the remainder were deemed to require no change from the existing ICRP methodology):

- The current TNUoS methodology does not recognise that low load factor, intermittent generation requires less transmission investment to accommodate its output pattern than a conventional generator at a particular location (theme 1). A model put forward by NGET was used as a starting point for discussion for the debate.
- Security provision associated with island links (theme 3).
- Treatment of HVDC links that parallel the NETS (theme 4)
- G:D split and compliance with European legislation (theme 6)

1.15. These are discussed in turn below.

Theme 1

1.16. The current charging methodology is based on the principle of ICRP. Behind the current ICRP methodology (and modelled under the status quo approach) is an

[53] para 4.30 of NGET's conclusions report ECM-24.

implicit assumption that transmission expansion is driven by conditions around peak demand as historically most investment has been required to meet peak demand conditions. This aligns with the traditional SQSS deterministic assessment[54] which, whilst including year round analysis, historically has been peak based as this has been the main driver for incremental capacity, i.e. the level required at peak is generally sufficient year round. Investing to meet peak demand was therefore assumed to trigger sufficient transmission capacity to avoid excessive constraints at other times of the year.

1.17. While a large number of combinations of generator output are possible under peak demand conditions, the current Transport model (of the ICRP methodology) uses only one, based on a uniform scaling, i.e. all contracted generation is uniformly scaled to match the peak MW demand based on the total level of access right (TEC)[55]. The scaling factor is to approximate a uniform level of load factor[56] across the system to ensure that total generation in the load flow matches peak demand. The uniform scaling approach intrinsically assumed that all generation is equally likely to be running at system peak, reflecting the equal right that all contracted parties have to export to the maximum value of their TEC. Further detail on the current Transport model is set out in appendix 6.

1.18. However, due to the changing generation mix, the NETS SQSS requirement to consider the year round use of the transmission system in the design of the MITS is becoming increasingly significant (i.e. while transmission investment for conventional plant is mostly driven by the need to meet peak demand, due to the variability of its fuel source, less reliance can be placed on wind generation contributing to meeting peak demand).

1.19. It is also recognised that intermittent generation (and renewable generation more generally) requires less transmission investment to accommodate its output pattern than a conventional generator at a particular location.[57]

1.20. To reflect these factors, we instructed Redpoint to model (reflecting the consensus of the WG) an incremental change to the ICRP methodology to reflect the year round requirements of the system, and also account for demand security requirements recognising the reduced ability of intermittent generation to be relied upon to secure demand.

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[54] The assessment was based on the assumption that the transmission system will not unduly restrict generation from contributing to demand security.

[55] TEC is a financially firm product and gives Users full access to the level of capacity reservation for the full financial year.

[56] The amount of power a generator produces over a period of time, quoted as a proportion of the maximum amount of power it could produce during that period, is referred to as the generator's load factor.

[57] For example, in areas of the system dominated by wind, power flows will be highest at the windiest times of the year rather than at times of peak demand (i.e. the output at other 'non-peak' times to the year are the main driver for investment). It follows that the network will be sized to consider these higher capacity requirements. However, it does not necessarily follow that the network will be sized to accommodate the full capacity of wind. This is because such a high level of wind output would only be realised for a relatively small period during a year of operation. The cost of investment needs to be balanced against the risk of increased, year round operational costs of the system.

1.21. As a proxy for this effect, it is proposed to utilise a year round background within the existing TNUoS Transport model, alongside the existing system peak (demand security) background for assessing the incremental transmission network costs imposed by generators. This is achieved through charging for two separate components of wider system use: a Peak Security charge for network capacity requirements driven at peak demand conditions and a Year Round charge for network capacity requirements driven throughout a year of operation.

1.22. The other key features of the improved ICRP policy option (Theme 1) are:

- the application of fixed percentages per generation technology under each assessment background (instead of a uniform scalar under a single scenario) in the background setting process to reflect a reasonable proxy for economic investment in the transmission system, and

- The use of individual generator load factors in the year round transmission charge calculations.[58] The modelling has applied NGET's suggestion that a suitable proxy that is representative of the long term year round impact of the user on the transmission system is an annual load factor (ALF) specific to each individual generator (its historical output over the last five financial years).

1.23. In essence, there would be two wider locational tariffs; one reflecting those generators that meet the demand criteria and one for those that do not (i.e. wind generators in wind dominated areas).

1.24. It is important to clarify that the improved ICRP modelling approach does not seek to change users' transmission access rights, with generators continuing to have firm transmission access rights in accordance with their TEC. The implicit assumption of transmission network capacity sharing by generators of different characteristics is reflective of the assumptions made in the network capacity investment decision.

Theme 3

1.25. The issue of security provision applicable to island links was debated at length by the WG (theme 3). A key area of discussion was that, under the current MITS boundary criterion, if the planned reinforcements linking the Scottish islands to the mainland transmission network were to proceed the transmission link between local substation of connection located on the island and the first MITS substation located on the mainland would form part of the wider transmission network. This would likely lead to the creation of an additional generation TNUoS zone for each link due

[58] It is proposed that a generator's specific output, within the same generation class, over an extended period of time is reflective of assumptions made about a generators' operating regime in transmission planning timescales, and therefore its effect on transmission investment it triggers for year round operation of the system. It follows that the year round locational tariff for a generation user should be based on the specific output of that generator over time. It is not intended as accurate reflection of a generators actual output over a particular twelve month charging period.

to the significant cost of sub-sea cable connections. While this would result in identical locational differentials between the island and mainland connection points determined under a local circuit charge, the tariff calculation would not be multiplied by a specific local security factor (i.e. 1.0), but the global security factor (currently 1.8) applied to all wider infrastructure assets.

1.26. The WG debate noted that by applying a 'baseline' status quo approach the island link may therefore not benefit from the application of a specific security factor reflecting the actual security provision of the link, which has the effect of reducing tariffs for less secure connections (reflecting the likely situation that the loss of a single circuit would result in complete loss of access to the network). As such, generators would not have firm access to the wider network and would not receive compensation for loss of transmission access due to loss/unavailability of the single circuit sub sea section of the link.

1.27. To remedy this, the discussion identified a potential improvement to the application of the 'baseline' methodology to better reflect the level of redundancy associated with a single circuit cable link in the wider zonal tariff calculation.

1.28. The key parameters of the improved ICRP charging approach we asked Redpoint to model are set out in the table below.

Theme	**Improved ICRP**
1	• We instructed Redpoint to model on the basis of a dual background approach to the Transport Model, background scaling factors consistent with NETS SQSS proposals under GSR009 and a two part tariff ('peak security' and 'year round'). This reflects the consensus approach put forward by the majority of the WG. • The WG was unable to agree whether intermittent plant should contribute only to the year round tariff element or both the year round and peak security elements. We instructed Redpoint to model on the basis that intermittent plant contributes to the year round element on the understanding that this approach most accurately reflects the transmission investment planning process, and therefore the costs of transmission investment (i.e. TO's costs) built in accordance with the NETS SQSS. We consider that under this approach the TNUoS charges would be more reflective of the incremental impact that users of the network at different locations and of different characteristics would have on the costs of transmission investment (i.e. TO's costs) relative to the status quo. We note the view that network investment would be required to accommodate intermittent generation at peak if it is located in an area with low generation diversity. We recognise that there are areas of the NGET's proposals that require further examination, but we consider that the current proposal represents an acceptable improvement for the purposes of modelling.

	• Peak security tariffs will be charged on the basis of capacity (as exists under the current TNUoS arrangements) reflecting the highest TEC (MW) applicable to that power station for that Financial Year [59] • The WG was unable to agree the basis on which the year round element of tariffs should be charged. We instructed Redpoint to base year round tariffs on TEC x specific historic annual load factor (historical output over the previous 5 years) on the basis of the supporting analysis provided by NGET demonstrated a reasonable level of correlation between load factor and constraints that can positively assist in the determination of the future level of transmission investment required over time and better reflects the impact on investment requirements of network users with different characteristics than the status quo (i.e. those who utilise the network less generally require less investment on a 'year round' cost benefit basis).
2	• No change from the existing TNUoS methodology.
3	• No change from the existing TNUoS methodology for zoning criteria[60] for the wider network and for the definition of the local/wider boundary[61]. • No change from the status quo model defined above for the local network for the following categories of "local" connection: (i) Onshore, (ii) Island link connected to the onshore local network (iii) Offshore • We instructed Redpoint to model island connections that would be classed as wider for charging purposes but which have reduced security due to reliance on a single sub-sea circuit as if the sub-sea circuit had a security factor of 1 (and not the global average security factor, currently 1.8). This would mean that the global security factor (1.8) would be used for all circuits that meet the MITS boundary criteria except for the single sub-sea circuit between the island group and the mainland that would have a specific factor of 1.0 for this section of cable.[62]
4	• We instructed Redpoint to determine impedance from an HVDC power flow as the average of a ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses. This reflects the consensus approach put forward by the WG. • As for the status quo charging approach defined above, and for the same reasons, we instructed Redpoint to include all costs (cable and converter) in the calculation of the expansion factor. • In addition, we instructed Redpoint to conduct a policy option sensitivity around applying a different cost treatment based on consideration of whether the link will parallel the onshore transmission network or not. The proposed approach involved the removal of all converter station costs of applicable HVDC links that run parallel to the onshore AC network (i.e. 'bootstraps') from the expansion

[59] The chargeable capacity for power stations with negative wider generation tariffs would continue to be the average of the capped metered volumes during three settlement periods of the highest and next highest metered volumes which are separated from each other by at least 10 Clear Days, between November and February of the relevant Financial Year inclusive.
[60] As defined in 14.15.26 of NGET's Methodology Statement.
[61] As defined in 14.15.17 of NGET's Methodology Statement.
[62] The methodology will reflect the level of redundancy associated with the single sub-sea link in the zonal tariff calculation by modifying the specific expansion factor applicable to the sub-sea cable section of the island connection included in this part of the wider network. This would be done by dividing the expansion factor by the prevailing global security factor (i.e. the expansion factor for the sub-sea section would be calculated by dividing the unit cost by the applicable global security factor, currently 1.8).

	factor calculation (and recovery from the residual element of TNUoS). The costs of converter stations associated with all radial HVDC links - that do not parallel the onshore network - would be included in the expansion factor calculation. [63]
5	• No change from the existing TNUoS methodology
6	• No change from the status quo model defined above

Socialised

1.29. This option relates to possible changes to replace the current locational TNUoS charging arrangements with a non-locational transmission charging model that spreads (or socialises) the costs across all users through a uniform charge (a socialised approach).

1.30. Key issues with this approach concern the basis on which charges should be levied (and therefore the extent to which they reflect the characteristics of different generators – theme 1), whether only wider or all costs should be socialised (i.e. apply a uniform tariff throughout and remove local infrastructure asset charges; relevant for themes 1 and 2) and whether demand charges should be socialised also (theme 2).

1.31. Of all its discussions, the WG had most difficulty arriving at consensus and providing robust justifications in these areas. We have therefore had to make more decisions for this charging approach for the purposes of modelling, including the introduction of a variant put forward by a group of WG members (discussed below). In doing so a key consideration has been the desire to avoid the introduction of a charging approach that would differentiate costs between generation users of the network on the basis of a specific geographical location or topological situation where it could not be robustly justified.

1.32. A group of WG members proposed a modelling approach that would retain the current local differentiation distinction within a socialised charging approach. Under this approach it was proposed that the defining feature of the socialised approach, a uniform tariff, would apply only for use of the MITS network and proposed to retain the cost reflective tariff (as established under ECM-11) for infrastructure assets that do not meet the MITS boundary criteria (e.g. radial offshore connections, radial island links and radial connections in specific geographical areas of Scotland). One justification for this view was the belief that the removal of a cost reflective signal in the local network would reduce the incentive on potential users seeking connection to the network to make efficient choices in local transmission connection designs (the rationale for its original introduction under ECM-11).

1.33. Another group of WG members presented the view that, as uniform charges have been proposed as a means of supporting renewable generation generally and of improving the business case of large number of sites where there is the high resource more specifically (and location is relatively inflexible), an approach that

[63] For the avoidance of doubt, the costs of converter stations associated with all radial HVDC links - that do not parallel the onshore network - would be included in the expansion factor calculation.

assumes that the costs of local assets is recovered through a uniform tariff to all infrastructure assets is the most appropriate modelling solution to adopt in for a socialised charging approach.

1.34. The same WG members raised concerns that the retention of a local differentiation within a socialised charging approach increases the risk of inefficient choices being made by generators seeking connection in a local context, i.e. "over engineered" solutions may become more prevalent to ensure that local transmission connection design purposely meets the MITS boundary criteria to avoid exposure to a sharper/higher local cost signal (and guarantee exposure to a lower uniform tariff). Some members highlighted the risk that such an approach may also influence the commercial siting decisions of potential generators towards locating in areas of the network where connection to the MITS was more likely.

1.35. Following on from this some WG members made the further point that the rationale for identifying a more accurate impact on relevant assets by splitting out a local network (ECM-11), particularly for those generators seeking to connect with less secure designs at the periphery of the MITS network (comprised of intermittent, renewable generation technologies[64]) seems at odds with an approach that in principle is seeking to spread the cost impact arising from siting decisions of generators connecting into areas of the network that impose the greatest cost in terms of network flows and associated investment across all users of the system. Members of this group also presented the view that there does not seem to be the same requirement to improve the cost reflectivity of charging for local assets under a socialised charging approach as this would appear to be against the central aim of socialised tariffs which was on ensuring accurate cost recovery rather than signalling the cost of transmission investment at any particular location on the network.

1.36. In terms of theme 2, we instructed Redpoint to remove the local/wider boundary and model on the basis that all costs are socialised under the 'base case' approach. However, we understand the argument that local cost signals where generators have choice about their connections need not be inconsistent with socialised charging on the wider network. Hence, we considered it appropriate for Redpoint to conduct a policy option sensitivity around retaining the local/wider boundary and socialising only wider charges.

1.37. The key parameters of the socialised charging approach we asked Redpoint to model are set out in the table below.

[64] Prior to the ECM-11, while individual generators were fully exposed to the consequence of access restrictions that result from their design variations there was no direct reflection in their TNUoS charges of the capital costs (or savings) associated with variations to connection designs.

Theme	Socialised
1	• The WG was unable to decide whether charges should be levied on a capacity (MW) or energy (MWh) basis. We instructed Redpoint to model socialised generator charges on a £ per MWh basis. Either approach is feasible, but we consider £ per MWh is more consistent with the principle that generators who use the system more should pay more (i.e. a MWh charge is more reflective of an individual user's operating behaviour than a MW charge). • We instructed Redpoint to model demand charges as the existing mix of MW and MWh/kWh charges in order to maintain the Triad signal. The Triad plays an important role signalling to demand users the cost of transmission at peak and no strong arguments were put forward for removing it. We also recognise the practical billing and implementation issues that would accompany any change to the Triad.
2	• The WG was unable to agree whether to retain the local/wider boundary or socialise all costs, or whether to continue calculating demand charges using the existing ICRP approach or socialise these too. • We instructed Redpoint to remove the local/wider boundary and model on the basis that all costs are socialised under the 'base case' approach. • We understand the argument that local cost signals where generators have choice about their connections need not be inconsistent with socialised charging on the wider network. Hence, we considered it appropriate for Redpoint to conduct a policy option sensitivity around retaining the local/wider boundary and socialising only wider charges. • In the case of demand charges we instructed Redpoint to model these on the basis they are socialised also, so that demand users pay the same MW or MWh/kWh rate irrespective of location.[65]
3	• Base case: Not relevant since removing the local/wider boundary distinction • Sensitivity: no change from the local security factors applied under the status quo model defined above.
4	• Not relevant
5	• No change from the existing TNUoS methodology
6	• No change from the status quo model defined above

[65] We note the divergent views of the WG on this issue; some raised concerns about removing the locational signal from generator transmission charging but leaving it in place for demand charging and others believing that the existence of differences in aspects of the current methodology between generation and demand (i.e. infrastructure / connection asset boundary is different for demand where charges are levied on the demand of the supplier across a whole GSP group) meant that there was sufficient precedent for a different treatment for demand. On balance we consider it is inconsistent to remove locational charging from generators but retain it for demand users.

Appendix 5 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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