Promoting choice and value
**for all gas and electricity customers**

# Electricity transmission charging arrangements: Significant Code Review conclusions

## Conclusion

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**Overview:**

The aim of Project TransmiT is to ensure that appropriate 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.

Ofgem has completed its review of TNUoS charging arrangements as part of Project TransmiT and this document sets out our conclusions. We will issue a direction to National Grid Electricity Transmission plc (NGET) later this month to give effect to our decision. This will require NGET to raise a Connection and Use of System Code (CUSC) Amendment Proposal to amend the TNUoS charging methodology to address the issues within the charging methodology that we have identified.

We note the high level of industry engagement and contribution in the Project TransmiT process to date. We value this input and consider the consultative nature of the process has been instrumental in contributing to the development of our thinking.

# Context

Great 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, with the electricity generation mix changing rapidly.

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. It has been 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

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

Modelling the Impact of Transmission Charging Options – A report by Redpoint Energy Limited, December 2011
http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

Project TransmiT - Electricity transmission charging: assessment of options for change, December 2011
http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Project%20TransmiT%20Dec11.pdf

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

# Contents

# Executive Summary

The current electricity transmission charging regime has served customers well by promoting the efficient use and development of the network. This has helped to avoid unnecessary costs to consumers. However, the mix of electricity generation is changing rapidly, with more renewable and low carbon generators connecting to the network. It has therefore been right for us to step back and review the approach.

Project TransmiT is Ofgem's independent and open review of electricity transmission charging and associated connection arrangements. We considered three main charging options:

- **Status Quo** (Investment Cost Related Pricing (ICRP)): retaining the existing Transmission Network Use of System (TNUoS) charging methodology.
- **Improved ICRP**: incrementally changing the current charging approach to improve the accuracy of cost targeting for generation charges.
- **Socialisation**: recovering transmission costs through a uniform £/MWh tariff applied to all generation users, whatever their type and location.

We 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 goals 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 would 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 were observed through the impacts on power sector costs and consumer bills, especially between the Status Quo and Socialisation approaches. However, the choice between Improved ICRP and retaining the Status Quo was not clear cut.

Based on our assessment of the evidence, we consulted in December 2011 on:

- Not progressing socialised charging as an option for transmission charging.
- Improved ICRP being the right direction for transmission charging.

Since publication, we have also been engaging with stakeholders to answer queries on our consultant's (Redpoint Energy Limited) modelling and our consultation.

In March 2012, we identified an issue with Redpoint's modelling results that we used to inform our December consultation. Following investigation of the issue with Redpoint, we do not consider the issue materially alters our conclusions.

Taking into consideration the responses to our proposals and our further analysis, **we are confirming the view set out in December that we should not progress a socialised approach to charging**. Whilst the socialised approach reduces the risk of not meeting the UK government's 2020 renewable generation target for any given level of government support, our analysis indicates that:

- It would do so at disproportionate cost to consumers and the power sector.
- It would exacerbate existing regional patterns of fuel poverty.
- It risks straying into areas of UK government policy around the degree of support for low carbon generation, which could cause confusion.

The modelling results suggest that the choice between Improved ICRP and the Status Quo is not clear cut. However, we remain of the view that **an improved form of ICRP is the best way forward** because:

- Charging arrangements need to evolve and better reflect the changing electricity generation mix and the impact different users have on transmission investment decisions.
- Our analysis shows that cost reflectivity drives more efficient decisions by market participants and policy makers which creates value for consumers.

As part of Project TransmiT we have only modelled one form of Improved ICRP and we expect that the approach can be improved further. Given that much of the work has now been done, we think industry is best placed to further progress this work to consider alternatives that best deliver the Project TransmiT objectives and drive further benefits for consumers in conjunction with developing the detailed changes to the relevant industry codes.

Alongside this, industry will also need to progress changes consistent with the improved form of ICRP to reflect impending issues such as the development of potential island connections and High Voltage Direct Current (HVDC) technology.

We are therefore directing National Grid Electricity Transmission plc (NGET) to raise an amendment proposal to ensure that the TNUoS methodology:

- Better reflects the costs imposed by different types of generators (in particular renewable generators) on the electricity transmission network.
- Appropriately takes into account the potential Scottish island links that are currently being considered.
- Takes account of the development of HVDC links that will run parallel to the onshore network.

This decision will not result in any changes to transmission charges at this stage but will start **an industry led process to further develop an improved form of ICRP**. Once this industry process is complete we will then be presented with the industry's amendment proposal, which we will decide whether to approve for implementation.

# 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. Our work on electricity connection issues (such as timely connections and user commitment) under Project TransmiT has been progressed separately. This work recently concluded with a decision on industry proposals on new enduring electricity user commitment arrangements[1] and the introduction of an electricity transmission licence reporting obligation to gather further information in support of arrangements to facilitate timely connections[2].

1.3. This document focuses on the electricity transmission charging issues that we have considered under the Significant Code Review (SCR) process[3]. It also signals the end of the SCR and initiates an industry led process to further develop the Transmission Network Use of System (TNUoS) charging methodology. Our decision will be given effect by issuing a direction to National Grid Electricity Transmission plc (NGET) to raise an amendment proposal under the Connection and Use of System Code (CUSC), which we plan to do later this month.

1.4. It is important to note that while this signals the end of the SCR component of Project TransmiT, it does not signal the end of the process or our involvement. The SCR direction will initiate the normal CUSC governance process, which will involve a further stage of industry led work and consultation before a final CUSC amendment report is sent to us for decision. As part of this assessment, parties to the CUSC will be able to suggest alternatives that would provide potential improvements to the current methodology in a manner consistent with the Project TransmiT principles for us to assess.

1.5. The CUSC panel will send an amendment report to us once the industry process has run its course. This will set out the panel's recommendations on the proposal(s) (and any alternatives) and provide evidence assessing these amendments against the relevant objectives of the CUSC. Industry will decide the manner and timing of the industry process, but we note that the standard CUSC

[1] http://www.ofgem.gov.uk/Licensing/ElecCodes/CUSC/Amend/Documents1/CMP%20192%20D.pdf

[2] http://www.ofgem.gov.uk/Licensing/Work/Notices/ModNotice/Documents1/Modification%20of%20SLC%208%20and%20SLC%20D4A.pdf

[3] An SCR is a holistic review of a code based issue, and can, if appropriate, result in changes being brought forward to more than one code.

process to advance and develop amendment proposals takes approximately six months to complete. We note that there is scope for this to be extended if necessary to allow further assessment and consultation of the issues within the charging methodology that we have identified. However, we continue to urge industry to expedite this process and submit a final CUSC amendment report, with all the requisite justification and evidence, in a timely manner to ensure benefits are realised as quickly as possible. Our role then will be to approve or reject the proposed changes to the charging methodology.

1.6. We note the high level of industry engagement and contribution in the TransmiT process to date. We value this input and consider the consultative nature of the process has been instrumental in contributing to the development of our thinking.

## Structure of this document

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

- Chapter 2 – contains our summary of the developments following our December 2011 consultation
- Chapter 3 - sets out a summary of the views expressed by respondents on charging models and our views on the issues raised
- Chapter 4 – sets out a summary of the views expressed by respondents on the treatment of High Voltage Direct Current (HVDC), islands and other policy issues and our views on the issues raised
- Chapter 5 – sets out our conclusions
- Chapter 6 – sets out the next steps
- Appendix 1 – summarises the responses to the December 2011 consultation questions and provides a summary of the views expressed by respondents on the modelling approach
- Appendix 2 – sets out our wider sustainability assessment.

# 2. Our December 2011 consultation and subsequent developments

2.1. This chapter sets out:

- A summary of the assessment presented in our December 2011 consultation.
- Our subsequent engagement with the wider stakeholder community.
- Developments since the publication of our assessment of the impacts of each of the options.

## Our December 2011 consultation

2.2. We developed with industry potential options for changes to the TNUoS charging arrangements as part of the Project TransmiT SCR. The December 2011 consultation set out our assessment of the impacts of the potential options, and our initial views on the way forward.

2.3. As part of the SCR we assessed three main options:[4]

- **Status Quo** (Investment Cost Related Pricing - ICRP): retaining the existing TNUoS charging methodology and making incremental changes to reflect impending issues (e.g. island connections and HVDC technology - "the bootstraps").
- **Improved ICRP:** incremental changes to improve the accuracy of cost targeting for generation charges. This does not include any changes to the arrangements relevant to the calculation of demand charges across GB.
- **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.

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

2.5. Based on the evidence collected and our assessment of it, the December 2011 consultation sought views on:

[4] We also modelled variants of the socialised and Improved ICRP approaches.

- Not progressing a socialised charging approach to transmission charging as an option.

- Our initial view that incrementally changing the current ICRP charging approach (hence "Improved ICRP") is the right direction for transmission charging and that further work should be carried out by industry to refine this approach.

2.6. Our analysis highlighted that all options examined are capable of meeting the binding 2020 renewable generation targets and maintaining security of supply. However, there are significant differences between the costs and consumer impacts of the different options.

2.7. The socialised charging approach was shown to be considerably more expensive in the period up to 2030 than the modelled form of the Status Quo, both in terms of the impact on power sector costs (£2.8bn to 2020 and £10.8bn for the period from 2021 to 2030) and on consumer bills (£6.9bn to 2020 and £12.9bn between 2021 and 2030). The increase in bills up to 2020 (~£11 per annum on average) was also shown to exacerbate existing patterns of regional fuel poverty. The approach did, however, reduce the risk of failing to meet the 2020 target should the UK government's Electricity Market Reform (EMR)[5] proposals not deliver. For any given level of government support the socialised approach reduced the risk of not meeting the UK government's 2020 renewable generation target. However we deemed the additional cost disproportionate and considered that formulating regulatory policy on the basis that the EMR does not deliver would be inappropriate based on our discussions with the UK government. For these reasons we considered it appropriate not to progress the socialised charging approach.

2.8. The choice between the Improved ICRP and Status Quo options was less clear cut.

2.9. Table 1 below shows the total impact on power sector costs and its main components for the modelled form of Improved ICRP versus the modelled form of the Status Quo as set out in our December 2011 consultation. The table shows this total net benefit to 2020 and for the period between 2021 and 2030[6].

[5] 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.

[6] This table reproduces Redpoint's analytical results published in December. Positive figures represent cost increases relative to the Status Quo. Negative numbers represent cost decreases (savings) relative to the Status Quo.

Table 1: Modelled form of Improved ICRP analysis (Stage 2 modelling)

| | | Improved ICRP (£m real 2011) | |
|---|---|---|---|
| | | NPV 2011-2020 | NPV 2021 - 2030 |
| | | | |
| *Benefit relative to Status Quo* | | | |
| **Power sector costs** | Generation costs | 313 | 965 |
| | Transmission costs | -8 | -418 |
| | Constraint costs | -171 | -1,089 |
| | Carbon costs | -11 | -2 |
| | **Impact on power sector costs** | **122** | **-543** |
| | | | |
| **Consumer bills** | Wholesale costs (inc capacity payments) | -1,227 | -182 |
| | BSUoS | -85 | -547 |
| | Transmission losses | -123 | -491 |
| | Demand TNUoS charges | 98 | 62 |
| | Low carbon support | 441 | 644 |
| | **Impact on consumer bills** | **-897** | **-512** |

2.10. The December 2011 consultation document in its entirety therefore formed our assessment of the impacts of the Project TransmiT SCR options, and was not solely based on the quantitative analysis presented above.

2.11. Our wider sustainability assessment reinforced the broad conclusions in relation to a socialised charging option. Our impact assessment also supported our initial view that security of supply implications are similar across all modelled options.

2.12. Overall, our initial view was that the Improved ICRP option is likely to better facilitate competition than both the modelled options of Status Quo and Socialisation since it is more cost reflective and to that extent may reduce some discrimination within the charging arrangements. In addition, the modelled form of 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 the modelling at that date indicated it had a higher overall benefit in terms of cost to the power sector but a negative impact on consumer bills relative to the Status Quo (but far less of a negative impact than the Socialisation option). These reasons contributed to our initial view that an improved form of ICRP is worth pursuing further as part of the CUSC amendment process.

## Developments since our December 2011 consultation

### Wider stakeholder engagement

2.13. We have continued to engage with the wider stakeholder community since the publication of our assessment and initial views on the way forward in December

2011. This reflects our continued commitment to conduct Project TransmiT in an open, inclusive and transparent manner.

2.14. 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. We held a further stakeholder event in January 2012, and a further modelling workshop in February 2012.

2.15. Since publication, we have also been engaging with stakeholders to answer queries on Redpoint's modelling and our consultation. This has included:

- The Scottish Government and representatives of the Highlands and Islands.
- The Welsh Government.
- Consumer Focus.

**Modelling error in our December 2011 consultation[7]**

2.16. In March, we identified an issue with the modelling results presented in Redpoint's report which were used to inform our December consultation. Redpoint reported the wrong transmission cost impacts by using an intermediate step in the model (a forecast figure) rather than the modelled outturn costs. When the corrected results are presented using the outturn costs the modelled form of Improved ICRP has a slightly negative business case versus the Status Quo for power sector costs as well as consumer bills. In particular, the small positive benefit of £122m for overall power sector costs becomes a small disbenefit of £141m.

2.17. For Socialised, the magnitude of the change is small in absolute terms.

2.18. Table 2 below highlights the total impact on power sector costs and its main components for the modelled form of Improved ICRP versus the modelled form of the Status Quo using Redpoint's corrected transmission costs. Similarly, Table 3 highlights the total impact on power sector costs and its main components for the modelled form of the Socialised option versus the modelled form of the Status Quo.

[7] A full explanation of the error is set out in the addendum to Redpoint's December report published in parallel to this document.

Table 2: Modelled form of Improved ICRP analysis (Stage 2 modelling)

| | | Improved ICRP (£m real 2011) | |
|---|---|---|---|
| | | **NPV 2011-2020** | **NPV 2021 - 2030** |
| | | | |
| *Benefit relative to Status Quo* | | | |
| **Power sector costs** | Generation costs | 313 | 965 |
| | Transmission costs | -271 | -1,300 |
| | Constraint costs | -171 | -1,089 |
| | Carbon costs | -11 | -2 |
| | **Impact on power sector costs** | **-141** | **-1,425** |
| | | | |
| **Consumer bills** | Wholesale costs (inc capacity payments) | -1,227 | -182 |
| | BSUoS | -85 | -547 |
| | Transmission losses | -123 | -491 |
| | Demand TNUoS charges | -126 | -688 |
| | Low carbon support | 441 | 644 |
| | **Impact on consumer bills** | **-1,120** | **-1,263** |

N.B. a positive number represents a benefit (cost saving), with a negative number indicating an increase in costs relative to the modelled form of Status Quo.

Table 3: Modelled form of Socialised analysis (Stage 2 modelling)

| | | Socialised (£m real 2011) | |
|---|---|---|---|
| | | **NPV 2011-2020** | **NPV 2021 - 2030** |
| | | | |
| *Benefit relative to Status Quo* | | | |
| **Power sector costs** | Generation costs | 453 | 1,803 |
| | Transmission costs | -1,484 | -7,856 |
| | Constraint costs | -1,452 | -4,535 |
| | Carbon costs | -201 | -218 |
| | **Impact on power sector costs** | **-2,684** | **-10,806** |
| | | | |
| **Consumer bills** | Wholesale costs (inc capacity payments) | -6,157 | -6,843 |
| | BSUoS | -723 | -2,276 |
| | Transmission losses | -553 | -2,693 |
| | Demand TNUoS charges | -776 | -4,388 |
| | Low carbon support | 1,406 | 3,342 |
| | **Impact on consumer bills** | **-6,803** | **-12,859** |

2.19. Table 4 below compares the analytical figures to illustrate the change in the Net Present Value (NPV) analysis using Redpoint's revised costs. The negative numbers indicate the additional costs relative to the December 2011 figures, while the positive numbers represent additional savings relative to the December 2011 figures.

Table 4: Change in NPV analysis using revised costs

| | NPV 2011-2020 | | Change in NPV 2011-2020 | NPV 2021-2030 | | Change in NPV 2021 - 2030 |
|---|---|---|---|---|---|---|
| *Benefit relative to Status Quo* | December | Revised | | December | Revised | |
| ***Improved ICRP*** | | | | | | |
| Power sector costs | 122 | -141 | -263 | -543 | -1,425 | -882 |
| Consumer bills | -897 | -1,120 | -223 | -512 | -1,263 | -751 |
| ***Socialised*** | | | | | | |
| Power sector costs | -2,769 | -2,684 | 85 | -10,823 | -10,806 | 17 |
| Consumer bills | -6,876 | -6,803 | 73 | -12,873 | -12,859 | 14 |

2.20. In absolute terms the change in NPV since December is small (of the order of 0.05% for power costs to 2020 in the modelled form of Improved ICRP). We therefore do not think that the modelling issue has changed circumstances materially since December. The costs of socialised charging remain disproportionately high, whereas the cost impacts suggest that the choice between the modelled forms of Improved ICRP and Status Quo is not clear cut.

# 3. Charging models

3.1. The December 2011 consultation set out two initial views. These were:

- That we should not progress socialised charging as an option for transmission charging and that we should reaffirm the principle of cost reflectivity.
- That the option of developing potential improvements to the current ICRP methodology (Improved ICRP) is the right direction for transmission charging arrangements and that further work should be carried out by industry to refine this approach.

3.2. Based on the evidence collected and our assessment of it, we have decided to confirm the position set out in our December 2011 consultation and direct industry to develop further and propose an improved form of ICRP.

3.3. This chapter sets out a high-level summary of the views expressed by respondents to the December 2011 consultation and our response to these.

## Not progressing Socialised charging

*Respondents' views*

3.4. The majority of respondents supported our initial view that a Socialised option should not be considered for implementation as part of the SCR process and agreed with the intention to reaffirm the principle of cost reflectivity for transmission charging. A small number of respondents queried the analytical results but did agree that improvements to the current methodology are required and were broadly supportive of the form of Improved ICRP used in the modelling exercise.

3.5. Conversely, a small number of respondents remained supportive of a socialised approach overall and rejected Ofgem's recommendation not to progress it. These respondents believed that a socialised approach would allow the UK to exploit more fully domestic energy sources and would facilitate faster achievement of strategic goals and renewable ambitions.

*Ofgem views*

3.6. Based on the evidence collected and our assessment of it, we have decided not to direct further consideration of 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 to consumers and the power sector.
- 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 the north of Scotland where fuel poverty is highest and least in London where fuel poverty is lowest.

- Socialising just the wider asset charges reduces costs and consumer bill impacts compared to full socialisation, but they are still significantly higher than for the Status Quo and Improved ICRP charging options.

- It risks straying into areas of government policy around the degree of subsidy for low carbon generation, which could cause confusion.

## Improvements to the current ICRP methodology

*Respondents' views*

3.7. Several respondents commented on the specific form of Improved ICRP used in the modelling and its merits as a basis for establishing the future direction of transmission charging. Their views were broadly split into three groups.

3.8. Firstly, a number of respondents supported proceeding with the form of Improved ICRP modelled on the basis that it produces a charging signal that better reflects the network investment cost impact of different generation technologies and the way in which transmission investment is evaluated relative to the current arrangements. They considered that a clear need had been established for the existing charging methodology to evolve and that an improved form of ICRP represented progress in the right direction.

3.9. Secondly, a number of respondents were in favour of proceeding with incremental changes to the current methodology but were concerned about the adoption of the specific form of Improved ICRP modelled. These respondents believed that further work is required to refine the approach through the industry-led stage of the process to ensure the best outcome.

3.10. A third group of respondents challenged the view that the modelled form of Improved ICRP is the right direction for transmission charging arrangements. The main concerns expressed by respondents unsupportive of the form of Improved ICRP modelled were:

- Its application to the islands of Western Isles, Orkney and Shetland may produce an "unacceptable solution".

- They considered that the current charging system, and not the modelled form of Improved ICRP, is the most efficient outcome when assessed against the SCR objectives and Ofgem's wider statutory duties, and pointed to the analysis which indicated that the modelled form of Improved ICRP might increase consumer bills in the longer term compared to the Status Quo.

*Ofgem views*

3.11. Our initial view in December that Improved ICRP is the right direction for transmission charging was not solely based on the quantitative analysis presented above. It was also because it is a more cost reflective methodology than the Status Quo which should, in principle, lead to more efficient decisions by market participants and policy makers and lower overall costs. Overall, we believe these considerations still apply.

3.12. In particular, there are two areas where we consider an Improved ICRP type approach to be more cost reflective:

- More accurately reflecting the economic trade-off each Transmission Owner makes between expected constraint costs and the cost of new transmission reinforcements when planning investment activity ("year round" considerations).

- Reflecting the fact that some transmission assets are provided to ensure peak security (which does not rely on intermittent generation).

3.13. The modelled form of Improved ICRP developed so far seeks to achieve this by having two separate tariff components: a peak-security charge (that intermittent generation does not pay), and a year-round charge (that takes into account how a plant uses the system through its load factor).

3.14. Moreover, there are many interactions within the electricity sector, e.g. between transmission and generator build decisions, transmission and balancing services charges, and the design of the EMR support mechanisms. We think that a cost reflective transmission charging methodology is less likely to create anomalies or distortions and is more likely to lead to an efficient decision making process and overall outcome. It also provides the foundation for other components of the electricity market to be developed in the knowledge that there is a cost reflective transmission regime in place.

3.15. We are also conscious of the fact that the modelling undertaken in December only considered benefits out to 2030. There may be benefits from some transmission investments that are not fully realised until after 2030 and are therefore not counted in the analysis. These benefits could include contributions to achieving the UK's 2050 Greenhouse Gas target. Assessment of the options against wider sustainability considerations and this analysis also supports improvements to the current ICRP methodology (see Appendix 2 for more details).

3.16. The modelling we undertook was based upon one formulation of Improved ICRP. There are complex interactions between the balancing mechanism and transmission under conditions of high intermittent capacity, and results may depend on the precise way these are modelled as well as a range of other assumptions. We are conscious that other formulations may have the potential of driving further benefits to consumers.

3.17. If we were to close the SCR by concluding that the Status Quo approach should be maintained then this may stifle further innovation and effort by industry to ensure that the charging methodology treats different users appropriately and delivers a good outcome for both the power sector and consumers. This would be despite broad acknowledgement that the Status Quo approach is becoming increasingly less analogous with how the network is planned - different generators do impose greater costs by triggering the build of more network assets, we consider that it is appropriate that the charging methodology reflects this.

3.18. Having considered all of the points raised above we think it remains appropriate to direct industry to further develop an improved form of ICRP and not to direct any further consideration of a socialised charging approach. In the section below we discuss our views on some of the issues around the modelled form of Improved ICRP which we will use to define the scope of our direction to help the industry process and maximise consumer benefits.

## Issues with the modelled form of Improved ICRP

3.19. Respondents that expressed concern about the adoption of the modelled form of Improved ICRP identified three central issues. These were:

- The proposed differentiation of circuits between "peak" and "year round" elements ("dual background" approach).
- How the year round charge is calculated and levied, and the assumed relationship between constraint costs and a historical Annual Load Factor (ALF).
- The proposed use of a 5-year historical ALF to determine future operating behaviour.

3.20. A summary of these views in each area, together with our views on the concerns expressed, are set out below.

**Dual background**

*Respondents' views*

3.21. Opinion differed on the application of a dual background approach in the calculation of transmission charges and the extension of the variable and flat scaling factors based on the recently modified the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS). The following range of divergent views was expressed:

- It is reasonable to introduce a form of 'improved' charging approach that reflects the introduction of a dual background based on the NETS SQSS.
- Transmission network investment is no longer solely being provided for peak requirements but also energy requirements driven by increasing renewable generation connecting to the transmission system.
- The modelling approach should seek to reflect the increasing trend of implicit sharing of network capacity amongst users with differing operating regimes within the charging arrangements.
- A movement towards the introduction of a dual background approach is reasonable if there is a robust justification that it better reflects the profile characteristics of system users and improves the accuracy of charges relative to the current approach.
- The differentiation between circuits is "artificial" and bears little relationship to the design of the system.
- Intermittent generation contributes more than 0% to peak demand security.
- A wider range of options for improvements than the version modelled should be considered.

*Ofgem views*

3.22. Based on our assessment of the views and evidence provided, we consider that mirroring the dual backgrounds applied in the NETS SQSS through application of a two part wider tariff in the Transport element of NGET's charging model should enhance cost reflectivity. We therefore consider that the industry assessment should investigate the merits of making a corresponding change to the TNUoS charging methodology to reflect the new NETS SQSS arrangements.

3.23. Taking forward this element in the development of an improved form of ICRP has the potential to deliver a solution that better facilitates the achievement of the relevant objectives as specified in NGET's electricity transmission licence[8] by enhancing cost reflectivity and better reflecting developments in the transmission business. In particular:

i. It better reflects the impact of different transmission users on network investment.

ii. It better reflects the fact that some transmission assets are provided to ensure peak security (which does not rely on intermittent generation).

[8] Standard Licence Condition C5 (5) of NGET's electricity transmission licence.

3.24. Some respondents were concerned that the dual background approach does not accurately reflect engineering reality. We recognise that this is a simplification, but is one that is also adopted in NGET's Transport model, which is only concerned with power transfers at each node. The intent of the proposed approach is therefore to provide a sharper correlation between the incremental flows identified with the resultant costs, not to replicate the engineering cost in the specific instance of an individual development.

3.25. Other respondents argued that the view that intermittent generation do not utilise the transmission system during peak periods required further testing. In response we note that the generation and demand background conditions are based on the recently modified NETS SQSS and were the subject of rigorous industry scrutiny. These discussions concluded that the NETS SQSS should consider transmission capacity requirements not only at peak demand periods, but also through the course of the year. The dual background approach provides a proxy of the required amount of transmission investment justified under cost-benefit analysis.

3.26. As a consequence, we consider the simplifying assumptions applied in the modelled form of Improved ICRP to be reasonable for the purposes of Redpoint's modelling exercise. However, we will direct NGET to further explore these issues through the CUSC process.

3.27. More generally, it is widely recognised that the cost-reflectivity of TNUoS is broadly based on the way users' impact on the need for transmission capacity stipulated by the deterministic rules[9] applicable to the planning and operation of the network (the NETS SQSS). The introduction of an explicit change to the NETS SQSS[10] therefore raises the expectation of a corresponding change to the TNUoS charging methodology. We also recognise that the charging methodology may need to make some simplifying assumptions when translating network planning rules into charges to ensure transparency, stability and practicality.

3.28. However, NGET's analysis showed an average wind load factor of 5% at peak, not 0%, suggesting that some network investment might be required to accommodate intermittent generation at peak, particularly if it is located in an area with low diversity in the generation mix. While we consider that the justification provided for the introduction of a dual background in NGET's Transport model is credible, there is a need for the CUSC process to further consider whether it is appropriate to further refine the arrangements on plant contributing to tariff elements, i.e. whether it is appropriate to assume that intermittent plant only contribute to the year round element. We encourage the industry process to seek to deliver arrangements that could represent an acceptable balance between increasing cost-reflectivity, simplicity and stability.

[9] Assessment is based on the assumption that the transmission system will not unduly restrict generation from contributing to demand security.
[10] NETS SQSS modification proposal GSR009 introduced changes to the transmission planning standards. Following GSR009, the NETS SQSS now obliges TOs to provide sufficient boundary capacity to fulfil two criteria: a demand security and economic (or 'year round') criterion.

## The proposed relationship between constraint costs and load factor

*Respondents' views*

3.29. A number of comments were received from a range of stakeholders in support of the proposed use of load factor in the form of Improved ICRP that has been modelled to derive the locational signals for the year round element of the tariff. These comments can be summarised in the following three broad statements.

- GB transmission licensees are justifying the funding of actual network build on the basis of year round considerations as well as peak requirements.
- The use of a load factor in transmission charging, although a simplification, could represent an acceptable balance between increasing cost-reflectivity and the resultant impact on the need for network investment.
- There is a clear correlation between plant load factor and its contribution towards constraint costs.

3.30. In contrast to the above points, there were several comments on the perceived weakness associated with the proposed use of historical ALF as a proxy of the broad impact of individual users on transmission investment requirements when planning network capacity. These respondents cited a range of factors in support of their view:

- It has not been robustly demonstrated that the modelled form of Improved ICRP is a more accurate reflection of network investment and the incremental cost of transmission.
- The premise that a generator's ALF is a reasonable proxy to reflect their use of the system in the future is flawed in its current form because (i) it relies on a sufficiently diverse plant mix in each charging zone[11], and (ii) there remains strong evidence that it is appropriate to continue to charge for transmission on a capacity basis only.
- Further work is required to consider alternative ways of charging by load that reduce the impact on overall network and generation costs, whilst ensuring we continue to meet energy deployment goals at the lowest cost to the consumer.
- The correlation between constraint costs and load factor degrades from 2016/17.

[11] For example, in an area dominated by wind generation a generator would have a locational signal derived to the same extent as one occupying an area where there is more sharing with conventional plant taking place, even though the impact on export flows from the areas could be very different.

- The present proposal appears to be better suited to intermittent generation than the plant required to provide the necessary backup on a continuous basis.

*Ofgem views*

3.31. We have sought to develop the ICRP methodology to improve the way users' impacts on the need for transmission capacity are reflected in the charging arrangements. The modelled form of Improved ICRP developed so far seeks to achieve this through the creation of two wider locational tariffs for generators: a peak-security wider tariff, and a year-round wider tariff.

3.32. The modelling has applied NGET's proposal that an ALF specific to each individual generator (its historical output over the last five financial years) is a suitable proxy for the long term year round impact of the user on the costs of the transmission system.

3.33. The intention of this approach is to deliver a more accurate signal of the costs imposed on the national transmission system and allow users to more accurately consider the economic costs of transmission to be factored into commercial decisions. Improvements in the accuracy of cost targeting would enable those who utilise the system less to receive reductions in the wider locational element of their year round tariff element. The general impact, indicated through Redpoint's modelling exercise, is that low load factor plant will pay less (or are paid less in negative charging zones) where they are deemed to share the network with counter-correlating plant (e.g. flexible thermal plant that can operate when there is no wind).

3.34. Evidence presented by NGET during the Project TransmiT technical working group discussions suggested that the correlation between load factor and constraint costs was better than the correlation observed between Transmission Entry Capacity (TEC) and constraint costs[12] and, over time, the former would provide a robust indication of the required amount of transmission investment justified under cost-benefit analysis.

3.35. However, the assumed relationship between load factor and constraint costs is a simplification as the generation mix within each charging zone also has an effect on the relationship. Furthermore, we recognise the concerns expressed that a completely linear relationship does not exist in all cases across many of the charging zones and NGET has shown that some degradation of the correlation is apparent as more wind generators connect to the transmission network in the medium to longer

[12] In the short term, without network reinforcement, increased levels of new generation connecting to the system can result in the potential for circuits to be overloaded in certain circumstances. Such overloads can be managed through operational intervention, requiring constraint payments to be made to affected generation parties. As more generation connects, there is a point when it becomes more economic to build additional transmission capacity to avoid increasing levels of constraints. This is a long run cost to the industry. TO investment planning decisions seek to balance these short and long term costs (i.e. determine an optimal level of constraints and beneficial reinforcement).

term. A more accurate reflection of this relationship may also drive further benefits to consumers. We agree that these concerns need to be explored further through the CUSC process.

3.36. We will therefore direct NGET to require the industry process to consider further the use of load factor to derive the locational signals which arise from the year round element of the tariff and other proxies, including whether the proposals:

- Better reflect the impact of different transmission system users on network investment and the incremental cost of transmission.
- Improve the accuracy of charges of different transmission users (e.g. between high and low load factor plants) across all areas of the network relative to the current methodology.
- Better achieve the relevant objectives as specified in NGET's electricity transmission licence.
- Would achieve a more favourable impact on consumers' bills relative to the current methodology.

3.37. The diversity of generation behind a given transmission boundary can have an impact on constraint costs. However, we also recognise that the inclusion of diversity considerations would increase the complexity of the proposal. We encourage the industry process to seek to deliver arrangements that could represent an acceptable balance between increasing cost-reflectivity, through taking into account the differing characteristics of transmission network users and resultant impact on the need for network investment, and the complexity of the arrangements.

3.38. We acknowledge the comment that the modelled form of Improved ICRP appears to allocate a higher share of network costs to generation technologies that are seen to provide peak security. In response, we point out that there is an ongoing requirement to ensure that there is sufficient transmission network capacity to ensure that demand at system peak can be met.

3.39. The modelled form of Improved ICRP seeks to ensure that the incremental cost of the required transmission network investment is charged appropriately. In line with this approach, the peak security element of the TNUoS tariff will be positive in some zones and negative in others. We think that it is reasonable that TNUoS charges signal the cost of transmission network investment and do not compensate generators for energy supplied at peak or any other time of year which we see as the role of the market arrangements.

**Use of 5-year historical ALF to derive a locational signal**

*Respondents' views*

3.40. The respondents who commented on this aspect of the modelled form of Improved ICRP were concerned that a generator would face future charges that are not based on their future use of the network but on previous operating behaviour. The key concern raised is that future, not past, behaviour drives efficient investment decisions.

3.41. Other respondents made the additional point that there are many variables that will determine the running profile of plant (such as cost of fuel, market conditions, etc.) each of which is likely to be outside of a generator's control and will increase the risk of an inaccurate proportion of charges being applied.

3.42. A few respondents highlighted that greater consideration is required on how the load factor of new plant (and thereby the application of charges) would be determined. One respondent questioned whether charges should be based on actual historical output or deemed historical output, noting that actual historical output may undervalue TO investment. Another respondent questioned whether it should be the lower, not the higher, of the dual background costs that determines the appropriate charging base to use.

3.43. One respondent expressed the view that the industry process should further consider use of a MW or MWh charge in the derivation of the year round tariff component.

*Ofgem views*

3.44. We acknowledge the comments received on the use of a historical load factor for the year round component. While we consider that the justification provided for elements of the form of Improved ICRP modelled that would convert the electrical power flow (measured in MWkm) from the Transport model into tariffs is credible (to produce a capacity based charge), we note that alternative approaches were raised in the technical working group discussion that merit further consideration as part of the CUSC amendment process. These alternatives may provide further benefits to consumers than the approach modelled so far. We will therefore direct NGET to require the industry process to investigate alternatives, including the four remaining options identified through the industry working group discussions:

- i) TEC only
- ii) TEC x generic load factor for plant type
- iii) TEC x specific forecast load factor (with reconciliation)
- iv) TEC x ex-post MWh

3.45. We will direct NGET to require the industry process to seek to deliver arrangements that could represent an acceptable balance between increasing cost-reflectivity, providing necessary information to NGET (in its role as System Operator), and simplicity and stability in tariffs.

3.46. One respondent suggested that the modelling should investigate charging using the lower of the year round or peak security electrical power flow to determine the relevant background in order to drive an 'economic' approach. In response, it is important to clarify that the transmission network is built to accommodate the greater of the requirements under the year-round and peak security criteria. We therefore consider it reasonable to charge on the basis of the higher flow as this is what drives the relevant investment and costs to be recovered through TNUoS charges.

3.47. The technical working group had detailed discussions on the form of the historical output to calculate a user's load factor in the year round tariff element (see section 4 of the Working Group Report)[13]. We accept that there are arguments in support of both the actual and deemed historical output[14], and conclude that this should be considered in the CUSC process along with the related points such as the historical period on which to base the load factor calculation.

3.48. It is important to clarify that the TransmiT SCR CUSC amendment process will not seek to change users' transmission access rights.

## Conclusion

3.49. For the reasons set out in this chapter, we have decided to direct industry to develop further and propose an improved form of ICRP further to ensure that the methodology appropriately reflects the costs that different users impose on the transmission system. We have also decided not to direct further consideration of a socialised approach to charging. More details of our direction to industry are set out in Chapter 5.

[13] http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/TransmiT%20WG%20Initial%20Report.pdf

[14] We note that Redpoint have separately confirmed that the annual load factors used in the calculation of the year round tariff element under the modelled form of Improved ICRP were unconstrained and therefore the equivalent of Final Physical Notifications rather than metered data. This is consistent with the discussions of the technical working group on this topic.

# 4. Treatment of islands, HVDC and other issues

4.1. This section sets out a summary of responses in relation to other key elements of the modelling work considered as part of our SCR work, namely:

- the treatment of potential transmission links to the Western Isles, Orkney and Shetland
- HVDC technology
- the split of revenue recovery between generation and demand[15]
- the need to take explicit account of potential long-term and strategic sustainability benefits when reviewing the charging methodology in future.

4.2. The section also sets out our views on these points.

## Treatment of the island links

4.3. Respondents with an interest in the development of generation on the Scottish islands were concerned that, while the approach modelled did reduce tariffs in mainland Scotland, the developments on the Western Isles, Orkney and Shetland still might not be economically viable and that the methodology should adjust accordingly. These concerns can be summarised in four broad categories:

  - Level of estimated charges.
  - Consistency with the modelling approach applied between mainland onshore generators and potential generators on the island groups.
  - Areas of potential definitional change to the TNUoS charging methodology.
  - Treatment of the island security factor.

4.4. A summary of the views in each area expressed by respondents and our views is set out below.

[15] The "G:D split" determines the share of network revenue recovered from generation and demand through TNUoS charges. This currently is set such that 27% of total revenue is recovered from generators and 73% is recovered from demand customers.

**Level of estimated charges**

*Respondents' views*

4.5. The majority of respondents with an interest in the development of generation on the islands commented that the analytical results appear to suggest that cost reflective charging would result in a level of transmission charge that would negatively impact on the viability of projects locating on the Western Isles, Orkney and Shetland.

4.6. Some suggested the following structural alterations to the TNUoS methodology:

- **Unit cost equalisation**: Adoption of a "notional" cost approach across the GB network, which is equivalent to assuming that all transmission circuits and voltages have the same unit costs. This would apply a single expansion factor (at a value of 1.0) across the entire network[16]. No underlying economic basis was provided for this approach.

- **Capping of island link unit costs**: Introduction of a cap to the value of the expansion factor applicable to each potential island link.

- **Application of a year round tariff element to island links**: This would allow potential island generators to receive a tariff that replicates a similar level of "load factor benefit" to generators located in existing charging zones by treating the island links as part of the Main Interconnected Transmission System (MITS) from a charging perspective.

- **External support**: The redistribution of subsidy levels that diesel power stations receive on some island groups[17] towards the cost of the proposed transmission links.

4.7. These changes would have the impact of further reducing the charges of potential generators locating on the three island groups under an Improved ICRP type approach.

4.8. A further group of respondents were of the opinion that the modelled form of Improved ICRP would make renewable generators seeking to locate on the islands

[16] The conversion rates are called Expansion Factors and are found by dividing the average cost of transmitting 1MW across 1km of each technology by the Expansion Constant, the weighted average unit cost of 400kV OHL circuits, i.e. the cheapest way to transport electricity in unit cost terms. The conversion rates apply to different technology sizes (i.e. 132kV) and types (i.e. underground cable) in both local and wider tariff calculations.

[17] Because of the low voltage (or non existent in the case of Shetland) nature of existing grid connections to the island groups, carbon intensive power stations are required to provide back up and baseload for a secure electricity supply on some islands. Government approved subsidy is provided to these power stations to ensure that the cost of power produced is affordable for end users.

served by such links comparatively 'worse off' relative to generation connected on the UK mainland (i.e. charge estimates produced are much larger than those on the Scottish mainland).

*Ofgem views*

4.9. The fundamental role of the charging arrangements is to recover the costs of providing transmission assets needed to transport electricity across the network. The economic rationale for cost reflective charging is that network costs should be borne by the users of the network who are responsible for imposing those costs. This principle currently applies across GB as a whole, including the Scottish islands.

4.10. Nonetheless, we have examined the impacts of adjusting the cost reflective principle through the charging options modelled. Our analysis has shown that increasing the extent to which costs are shared between users of the system would likely lead to less efficient transmission investment decisions over time and drive significantly greater costs to consumers and the power sector.

4.11. No evidence was provided in support of the view that it is appropriate for the charging arrangements to diverge from the current cost recovery function, or that the current principle of cost reflectivity should be altered to discriminate either in favour or against any class or type of generation user. We consider that in general Government is best placed to determine a preference or subsidy for one form of generation or one area of the country over another.

4.12. Even though it is more expensive to transport electricity over long distances to where it is consumed, Redpoint's modelling exercise adds to previous independent analysis[18] suggesting that it may still be economic to site generation in peripheral areas under a cost reflective charging approach. This position is supported by our modelling exercise.

4.13. We set out our views below on the alterations suggested by respondents.

Unit cost equalisation

4.14. No evidence was provided in support of the view that (through the effective removal of "expansion factors"[19]) all circuits and voltages should be assumed to have the same unit costs.

[18] Available from DECC's website: www.decc.gov.uk.
[19] There are three underlying reasons for the use of expansion factors in the current methodology: (i) as a proxy to reflect the higher cost per MW transported of lower voltage circuits, (ii) as a proxy to reflect the higher cost per MW transported of underground cable circuits, and (iii) as a proxy to reflect the expectation that, on average, a proportion of lower voltage circuits will not be uprated in the short to medium term.

4.15. Any change that seeks to reduce cost reflectivity introduces cross-subsidies which in turn could have a negative impact upon competition.

4.16. Furthermore, reducing (or effectively removing) expansion factors would increase the extent to which costs are shared between users. A charging methodology with a lower range of factors for all voltages and circuits would, all other things being equal, have a significantly narrower range of tariffs. At the extreme, an expansion factor set equal to one would be similar to a socialised form of charging as it would share cost differences between users of the system with no underlying economic basis and undermine the cost reflectivity of tariffs. Our analysis has shown that this would likely lead to less efficient transmission investment decisions over time. For the reasons set out above, we have decided not to progress such a charging approach.

Capping of island link unit costs

4.17. The application of an artificial cap raises similar concerns in relation to cost reflectivity and cross-subsidy as the option above on unit cost equalisation. It could, over time, distort decisions on the closure of older generation plant and the location of new plant, and lead to inefficient transmission investment.

4.18. The issue of the expansion constant (the weighted average unit cost of 400kV OHL circuits) and its use in the derivation of expansion factors (measures of costs relative to 400kV OHL circuits) was discussed at length by the industry as part of the technical working group discussions. These discussions reached the general consensus that the assumed unit costs of different costs could be updated following the RIIO[20] Transmission Price Control Review which will consider the issue. Based on the evidence presented, we do not consider this to be an issue that needs to be addressed by our direction as it would be more appropriate to consider it after the RIIO price control review has concluded under the CUSC's usual open governance arrangements.

Application of a year round tariff element to island links

4.19. We consider that there is justification for how we have treated the potential islands links under the form of Improved ICRP modelled. Nonetheless we acknowledge that there are alternative approaches that may merit further consideration as part of the industry process.

4.20. We consider that extending the charging methodology to islands should seek to reflect the following factors:

- The capital cost of the transmission links compared to other parts of the network (noting that they are subsea cables spanning long distances).

[20] Revenue = Incentives + Innovation + Outputs

- The variation in size, cost and design of potential links.
- The amount and type of generation in any new charging zones.

4.21. Some respondents argued that while the rationale behind the application of the year round tariff element, i.e. to reflect the level of implicit sharing of network capacity by stations with differing operating regimes, is not currently applicable on the islands there exists significant *potential* for such sharing. They argue this provides sufficient justification to apply the year round tariff element to all areas that meet the MITS charging criteria. NGET's proposal, and the modelled form of Improved ICRP used in our modelling exercise, was not based on the prospect of potential sharing and therefore did not apply this tariff element to the island links. This issue should be considered further under the CUSC process.

4.22. We will direct NGET to require the industry process to further consider whether the applicable generator locational tariff calculation for generators utilising potential island links should be consistent with the proposed application to the established mainland system (i.e. wider network tariff).

<u>External support</u>

4.23. We do not have sufficient evidence to suggest that the current methodology should be changed in order to ensure that charges are reduced in a particular area to a level that guarantees commercial viability of a particular development. We believe that the charging methodologies are not well suited to providing support to particular developments, technologies or areas of the network over others in an efficient and effective manner primarily because the methodologies have wider objectives. We consider that if financial support is required for the development of renewable generation in a particular region, then it is more appropriate for Government to take this action using what it considers to be a suitable mechanism.

4.24. Cost reflective charging also helps to ensure that consumers get the best value for the subsidy provided through the external support mechanism applied by Government. Once such a subsidy is in place it still makes economic sense to have cost reflective charging to ensure that cost differentials are taken advantage of and, whatever the target for renewable is, it is achieved at the lowest cost to existing and future consumers. Where particular schemes are deemed necessary to achieve the specified policy targets the value of the subsidy would be expected to rise to the level at which a more expensive scheme would also be viable.

4.25. We disagree with the view that the modelling exercise indicates that potential island generators will be "worse off" than mainland generators. A cost reflective charging approach will seek to reflect the economic costs of transmission to be factored into commercial decisions. One way it does this is through the use of factors that reflect the difference in unit cost between different circuit type and voltage. This is particularly important for the islands where the subsea connections are expensive cables (relative to the established network available on the mainland). Expensive connections will have a locational differential that is quite large when compared with a mainland point under the prevailing principles of the current ICRP model. If this approach is not applied, someone else has to fund these investments. If it is not generators requiring the new investment under network charges then it has to be suppliers, and ultimately electricity consumers, or taxpayers through a direct subsidy.

**Consistency - reflecting the unit cost of island infrastructure assets**

*Respondents' views*

4.26. Some respondents expressed a view that the treatment of costs applied by the modelling exercise is not consistent with the approach applied to the generality of the onshore transmission network. The main concerns expressed by these respondents were:

- The modelling approach applied to potential island links, utilising actual cost data and the application of a project specific circuit expansion factor, is qualitatively different to the structure used to determine the "local" TNUoS charges for mainland generation users, which is based on an average view of the unit costs to accommodate these flows.

- The modelling exercise used to provide an estimate of charges for the Western Isles, Orkney and Shetland is different to the methodology approach used to calculate charges for mainland transmission upgrades and for other islands (e.g. Skye or Anglesey). The cost approach applied for the generality of transmission infrastructure[21] should be extended across all island links.

- The modelling treatment of potential island links implied a similarity with the characteristics and charging treatment of radial offshore transmission system, which many respondents considered to be discriminatory because of the differences between them (i.e. island links will serve both generation and demand).

- The treatment of intermittent generation located onshore and connected to the MITS should be consistent throughout the UK. By not extending the established principles for charging onshore generators that are deemed to meet the MITS charging criteria to island generation may be in contravention of EU legislation, specifically Recital 63 of the Directive 2009/28/EC.

*Ofgem views*

4.27. The charging methodology should, where possible and practicable, seek to use the most accurate information available to determine charges to ensure cost-

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[21] The cost of expansion is subject to an averaging approach across all circuits by zone in the transmission licensees' areas.

reflectivity. This is something that NGET seeks to do already. Given the volume of assets commissioned on the system it is practical to group similar assets together. However, if significant variances arise that can be practically differentiated, NGET will consider moving to specific expansion factors for those assets. In the case of potential island connections, the cost of connection may be largely specific and practically identifiable and auditable. In those circumstances NGET may consider it reasonable to assume a specific expansion factor for the island connection. Our modelling approach sought to replicate this rationale.

4.28. We consider that an averaging approach and the application of a generic expansion factor across all potential links could inappropriately dilute the cost reflectivity of the resulting island tariff compared to a case-specific factor. We remain of the view that deriving an expansion factor using actual cost data is an appropriate way of achieving consistent cost-reflective tariffs. When considered in conjunction with the unchanged shallow charging boundary approach, we are satisfied that the modelled treatment provides a cost reflective signal of the costs that potential users impose at these particular points in the network (based on the best cost and design data available).

4.29. We agree that NGET's duty not to unduly discriminate in the application of its charging mechanisms is very important[22]. It requires NGET to consider the types and extent of services offered to different users, which will vary according to both the location and type of a particular user (i.e. generator or supplier). We think it is appropriate for each user of the system to pay charges which reflect the cost of an increment of usage of the system as far as reasonably practicable given the objectives of the charging methodology. As certain incremental costs will vary according to the location and the type of user involved, we think the current charging approach produces appropriate charges at a particular location reflecting the costs incurred by the relevant transmission licensee as a consequence of a change in demand or generation at each point on the system.

4.30. We therefore consider the modelling treatment applied to the potential island links, i.e. recovering the costs of potential island links via the prevailing methodology, is not unduly discriminatory. We have no evidence that the modelling treatment has been applied inconsistently or in a manner that discriminates either in favour or against any class or type of generation user.

4.31. We acknowledge the difference in modelling treatment of Orkney, Shetland and Western Isles to that used to calculate charges for mainland transmission upgrades and for other islands (e.g. Skye[23] or Anglesey[24]). The islands of Orkney,

[22] Standard Licence Condition C7(1) provides that NGET must not discriminate between any persons or class or classes of persons.
[23] The Isle of Skye is connected to the national transmission system by a short 132kV OHL line (over 500m of open water between an area north of Kylerhea on Skye and the mainland) and forms part of Generation TNUoS Zone 3. Zone 3 also includes the single transmission circuit on the Western Isles that connects into a GSP at Stornoway. However, the landmass of the Western Isles is not connected to the national transmission system; it is linked to Skye via a subsea distribution link. The Stornoway GSP has only one transmission circuit and therefore is not considered a MITS charging node.

Shetland and Western Isles are not currently captured within the prevailing methodology and the designs of the links themselves are not finalised. The Isle of Skye and Anglesey, on the other hand, have established overhead line transmission links to the mainland using the same assets that comprise the onshore networks. For this reason we think that it is appropriate to treat the relevant assets in the same manner as other onshore assets. There are discernible differences between these assets and the potential links to the islands (e.g. higher cost of assets as they are sub-sea and span long distances). We therefore consider it is appropriate to investigate the alternate methods through which to recover the costs of such potential links. We do not consider the modelling approach applied to date to be discriminatory.

4.32. We are not convinced that the existence of demand on the islands represents an obstacle to the introduction of arrangements that seek to create a more cost reflective signal of the costs that generators impose on the system. However, we do recognise that only one form of treatment has been modelled and will therefore direct NGET to require further work by industry to refine this approach and develop arrangements that better facilitate the achievement of the relevant objectives.

4.33. We are comfortable that the modelled form of Improved ICRP is compliant with EU legislation as it stands. That is to say, a cost reflective and non-discriminatory methodology attempts to reflect the cost of grid access as accurately and as fairly as practicable to incentivise users across GB to make efficient decisions about where they locate and about their connection security. This is particularly important for the islands where the proposed sub-sea links are of relatively high cost.

4.34. In terms of the specific comments received in relation to Directive 2009/28/EC, we note that Recital (63) refers to the production from peripheral regions being "unfairly disadvantaged", which it gives effect to through a prohibition on discriminatory tariffs (Article 16(3) and 16(6)).

4.35. We are content that the current cost reflective charging methodology is fully compliant with the above Directive and the Internal Market legislation, i.e. we think it does not unfairly disadvantage renewable generation in peripheral areas because it seeks to provide all users of the system with an accurate signal of the costs imposed on the national transmission system. Such signals when incorporated into the individual financial appraisals for market participants will assist in the development of a more economic and efficient transmission system. This minimises the costs that are ultimately borne by electricity consumers.

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[24] Anglesey is connected to the national electricity transmission system by a short 400kV OHL (over 200m of open water in parallel to the Britannia bridge) and forms its own generation TNUoS Zone (zone 11). This zone includes the double 400kV OHL circuits connecting the 960MW nuclear generation station at Wylfa to the 400kV Pentir substation (located on the mainland).

4.36. We also note that the Directive requires cost sharing rules to be based on objective, transparent and non-discriminatory criteria taking particular account of all the costs and benefits of the relevant type of production. Hence, the legislation permits (and does not prohibit) different charges to exist that reflect the existence of different costs for different producers.

4.37. We consider that the current TNUoS methodology is non-discriminatory, and is based upon a detailed analysis which takes proper account of the costs and benefits associated with the network costs imposed by different users. The cost sharing rules that underpin the modelled form of Improved ICRP seek to better reflect the different characteristics of generators, especially low load factor (which is the dominant generation source on the islands). We consider that this would assist in creating a more level playing field for generators relative to the Status Quo we have modelled.

**Definitional change - the local/wider boundary definition and its application to island links**

*Respondents' views*

4.38. A small number of respondents called for the CUSC amendment process to reconsider the charging definition and application of local and wider works in the context of island generation. One respondent considered that the MITS charging criteria underlying this approach is based on outdated definitions which are inappropriate for capturing the connection of renewable energy in peripheral areas.

4.39. A number of respondents with an interest in the development of generation on the islands thought that potential island links do not require a new definition for MITS (i.e. the local/wider boundary) but rather that the island links should be deemed MITS in advance of the criterion being met. These respondents noted that such an approach would anticipate island links becoming part of the MITS from a charging perspective before the design and cost of the transmission network capacity reinforcement has been finalised and approved by the Authority and before the investment work is complete by the relevant TO. Some parties considered that a revision of this nature would appreciably lower the tariff exposure for potential generators (relative to a non-MITS connection) for the entire project life and not just when the MITS boundary criterion is met.

*Ofgem views*

4.40. We believe that further work should be carried out by industry to consider whether it is appropriate to refine the application of the current MITS boundary definition to anticipate potential island links becoming part of the MITS from a charging perspective. However, this work must be mindful of not setting unintended precedents when developing policy and not being unduly discriminatory towards any particular users.

### Treatment of the island security factor

*Respondents' views*

4.41. The technical working group discussion noted a situation could arise where potential island connections for the Western Isles, Orkney and Shetland could shift from being a local circuit to being considered part of the wider transmission network under the existing charging methodology, due to the application of the local/wider boundary criteria. Generation connections that are deemed to meet the MITS boundary criteria are subject to the GB global security factor (currently 1.8), which is used in the calculation of a generator's TNUoS wider tariff. For generators connected at non-MITS nodes, the current charging arrangements identify the local network[25] to which a generator is connecting and apply a "local security factor" in the calculation of a local circuit tariff.

4.42. Onshore, the local security factor is specific to each generator and is set at either 1.0 (reflecting the likely situation that the loss of a single circuit in the local network would result in complete loss of access to the network) or equal to the wider factor (currently 1.8) for all other instances.[26]

4.43. The group agreed that it would be appropriate to reflect the reduced security that potential generators locating on the island groups when connected via a potential island link consisting of a section of single circuit would receive. This would mean that the global security factor (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.[27] This approach was applied in the modelled form of Improved ICRP.

4.44. The majority of respondents on this issue noted that reducing the security factor applicable to island links (forming part of the wider network) is a pragmatic development to the existing ICRP charging methodology to reflect the lack of redundancy in the subsea cable link. Some parties thought it was never a realistic prospect that potential island links would be charged a tariff comprising the wider security factor, and suggested that the modelling exercise had "disingenuously" modelled Status Quo in order to favourably portray the improved ICRP indicative tariff estimates.

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[25] Those assets whose primary purpose is to facilitate the connection of a generator to the transmission network.

[26] This approach does not provide further differentiation for the capacity between the extremes of single circuit and fully compliant designs. It therefore exposes all partially redundant (i.e. export capacity is not sufficient to allow full export during a single circuit outage) users to the costs of additional redundancy, up to the maximum level represented by the global factor.

[27] 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).

4.45. Another respondent considered that the process of consultation had not adequately acknowledged that they were critical of Ofgem's modelling decision on the applicable security factor for the islands that become part of the wider network or have single circuit links under the modelled form of Improved ICRP.

*Ofgem views*

4.46. Under the current prevailing methodology, if potential island links were to become part of the wider transmission network (e.g. if a Grid Supply Point was built in addition to two transmission circuits under the current methodology) this would likely lead to the creation of additional TNUoS zones due to the significant cost of sub-sea cable connections. This would result in similar locational differentials between the island and mainland connection points as the local circuit approach except that the tariff would no longer be multiplied by a specific local security factor (i.e. 1.0), but the wider security factor (i.e. 1.8), thus significantly increasing tariffs. Under the modelled form of Improved ICRP, a lower security factor was applied to the subsea cable link to reflect actual resilience.[28]

4.47. It is appropriate to reflect the reduced security that potential generators locating on the islands groups would receive when connected via a potential island link consisting of significant sections of single circuit, i.e. a security factor of 1.0 should be applied to those assets.[29] We conclude that this proposed treatment should be considered in the CUSC process (i.e. islands with single circuit sub-sea connections).

4.48. In exploring this further, it is important to be mindful of the risk of setting unintended precedents for dealing with a lack of redundancy on a radial piece of the transmission network. Any principles developed through the industry process should aim to be enduring universal principles. This will require careful consideration to ensure that the arrangements would only apply to other circuit links where it is appropriate to do so.

4.49. We disagree with the claim that our modelling exercise sought to portray favourably the island charge estimates produced under the modelled form of Improved ICRP relative to the Status Quo. The rationale underpinning the development of simplifying assumptions applicable to the Status Quo approach was that the modelling approach should reflect, where practical and appropriate:

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[28] 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.

[29] The methodology will reflect this in a potential zonal tariff calculation by modifying the expansion factor applicable to this section of single subsea 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 subsea link included as part of the wider network.

- a straight extrapolation of what the 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.

4.50. We believe this approach was applied throughout the methodology including to the proposed island links.

4.51. In response to the criticism of one respondent who felt that their involvement in this aspect of the working group debate had been omitted, we point out that the difference of opinion in question featured as part of the formal minutes of the working group and was referenced again in the final working group report, both of which are available from our website. We therefore disagree with the suggestion that the difference of opinion was not acknowledged.

**Ofgem conclusion on the treatment of islands**

4.52. We have decided to direct industry to consider further the treatment of island links within the charging methodology. This will require consideration of:

- The applicable expansion factor reflecting the unit costs of the links.
- Whether a year round tariff element should be applied.
- The island security factor to reflect the lack of redundancy provided by a single circuit.

4.53. Chapter 5 sets out more details on what will form our direction.

## Treatment of HVDC 'bootstrap' converter station costs

*Respondents' views*

4.54. Many respondents on this issue expressed the view that when HVDC equipment is used in parallel with the AC network, the converter stations will provide a significant amount of flexibility to the System Operator (SO) when operating the network. It was suggested that this flexibility is similar to that provided by comparable onshore equipment, the cost of which is recovered through the residual element of tariffs. The inference being that, because of this comparable utilisation, the recovery of costs associated with HVDC convertor stations should be through the residual element of tariffs.

4.55. Others respondents believed that HVDC converter stations for links that parallel the AC network had similar functionality to onshore AC substations in that they effectively link different elements of the transmission system and are likely to result in lower levels of cable losses compared to the situation in which the generation was connected by onshore link. These respondents considered this equivalent functionality to onshore AC substations provides a sufficient basis to justify the recovery of HVDC converter station costs through the residual element of tariffs.

4.56. A small number of respondents held a strong opinion that converter stations for all HVDC projects should be 'socialised' within the residual tariff and that this should apply as a general rule across both onshore and offshore investment (including radial links that do not parallel the onshore network). Some respondents noted that removing these converter costs from the capital cost of the island links would trigger a suitable reduction in the level of indicative charges for Scottish islands.

4.57. Others respondents expressed caution in determining an approach based on limited information and evidence. A few parties considered that there is a strong case that HVDC bootstrap converter stations should be charged locationally, but provided no quantitative evidence in support of their view.

4.58. One respondent commented that the modelling results indicate no material benefit from and no current justification for recovering the cost of HVDC bootstrap converter station costs through the residual element of tariffs. They were concerned that such an approach could lead to overinvestment.

4.59. Another respondent considered that the only difference between converter stations needed for HVDC lines and substations needed to link AC network is the increased expense of HVDC equipment. This led the respondent to conclude that substation costs (HVDC and AC) should be treated consistently, hence, either the costs of the assets should both be in the locational part of the charge, or both should be within the residual element of the tariff.

4.60. One respondent commented that removing the cost of HVDC converters stations for parallel links only from the expansion factor calculation appeared to be a reasonable way of reflecting some long term strategic sustainability issues. Another respondent set out its view that there are likely to be long term benefits from removing the costs of the converter stations from the costs of the transmission links in addition to "learning rates", but provided no detail on the nature and scope of these additional benefits. A further respondent set out its view that the adoption of HVDC technology provides a significant learning opportunity for the UK system, potentially to the benefit of all consumers, but provided no evidence to support this view.

*Ofgem views*

4.61. Several respondents commented on the treatment of HVDC converter station costs and the merits of consistency in the future direction of transmission charging, although there was no consensus on the appropriate treatment for the recovery of HVDC converter stations costs.

4.62. We agree that there are functional similarities between HVDC converter station assets and non-locational substation assets that exist onshore, and that the use of HVDC technology may have the potential to provide system operation advantages. However, we also note that the converter assets are an inherent component of a HVDC circuit, whose capacity and therefore cost is directly matched to capability of the link.[30]

4.63. Our modelling suggested very little difference in system costs between the modelled form of Improved ICRP and Status Quo, whilst the sustainability assessment suggested some possible benefits of recovering a proportion of the convertor stations in the residual element of tariffs due to their broad system functionality, optionality and innovation characteristics.

**Ofgem conclusion on the treatment of HVDC converter station costs**

4.64. We are therefore directing NGET to:

- Explore the alternate options to recover the costs of HVDC converter station costs that parallel the AC network (at each end of the circuit).
- Consider the extent to which the method of cost recovery through the charging methodology would deliver additional benefits in terms of its impact on renewable deployment, the achievement of long term policy goals and the impact on consumer costs. This also applies to the treatment of island links that use radial HVDC technology.

## Split of revenue recovery between generation and demand (the G:D split)

*Respondents' views*

4.65. Our December consultation set out an initial view that we do not think it is necessary to alter the G:D split at this stage, but that NGET should keep it under review and make proposals for change as and when necessary through the normal amendment process. This question was posed against the backdrop of our decision to model a reduction in the 'G' proportion in 2015 (G 15% : D 85%)[31] to reflect the assumed change in the G:D split to remain compliant with EU Tarification Guidelines.

4.66. Respondents were broadly split between those who believed that a decision on the potential proportions of G:D split should be taken more immediately, and those that thought a change was not necessary at this time. Respondents in this latter

[30] It is worth noting that the modelling error referred to in chapter 2 had the effect of reducing the apparent cost difference between the modelled form of Improved ICRP and a variant in which a proportion of converter station costs were recovered from the residual element of tariff.
[31] The "G:D split" is currently set such that 27% of total revenue is recovered from generators and 73% is recovered from demand customers.

group believed that any proposals for change should be progressed through the normal amendment process.

4.67. Of those that disagreed with Ofgem's view, their reasons fell within two broad categories. First, there was a concern that the lack of firm policy could lead to regulatory uncertainty and negatively affect the required adjustment of wholesale market contracts. Second, advocates of a reduction in the generator share towards zero argued that such a change would better align the UK with its European counterparts, thereby levelling the transmission charging playing field and improving the competitiveness of GB generation in Europe. No quantitative evidence was provided in support of these views.

4.68. Of those respondents that were supportive of our position to keep this issue under review, the following additional points were raised:

- If a change was agreed then a transition period of two full charging years would be required to accommodate this change within contracting arrangements.
- A reduction in the generator contribution could lead to inefficient generation decisions which would be passed through to consumers in the form of increased costs. This would require further consideration in advance of any potential change.
- Further clarification is required of the rationale for any change and a full assessment of the material impact upon consumers must be undertaken in advance of any potential change.

4.69. A respondent considered that it is vital that Ofgem provides independent scrutiny of any future proposals as there is a natural bias in the nature of stakeholder representation which may make it easier to progress proposals that seek to alter the split in favour of generators.

*Ofgem views*

4.70. Based on our assessment of the views and evidence provided, we still consider that it is not necessary to alter the G:D split at this stage and that NGET should keep this issue under review and make proposals for change as and when necessary through the normal amendment process. As part of this process we expect NGET to consider the EU Tarification Guidelines and the impact on trade between Member States.

4.71. We agree that further clarification is required of the rationale for any change and that there should be a full assessment of the material impact upon consumers in advance of any potential change. The CUSC process will consider the appropriate transitional arrangements associated with any potential change and will ensure that appropriate stakeholder consultation is conducted which should counteract any perceptions of "bias" within the governance process.

**Ofgem conclusion on the split of revenue recovery**

4.72. We have decided not to direct any changes to the G:D split as part of the SCR for the reasons stated above.

## Wider sustainability issues

*Respondents' views*

4.73. Two respondents commented that there may be value in NGET taking long term sustainability benefits into account, in addition to the current charging objectives, when reviewing the charging methodology. One respondent noted Ofgem's duty to have regard to the need to contribute to sustainable development, but expressed caution on 'overplaying' this consideration in matters of transmission charging where economic considerations are more important.

*Ofgem views*

4.74. We received limited response on this issue and no detailed comment on the form of any potential objective. Consequently, we do not propose changing the licence or directing changes to be made to the CUSC in relation to the current charging objectives at this stage.

**Ofgem conclusion on wider sustainability issues**

4.75. We will require due consideration to be given to the interests of present and future consumers, including in relation to the achievement of sustainable development, in formulating the amendment proposal so that these issues are considered as part of the CUSC process. We also encourage the CUSC panel to keep the Code's relevant objectives under review, e.g. to respond to any licence change by us in this policy area, and to give due regard to the need to contribute to sustainable development including the achievement of legally binding commitments and long-run sustainability goals.

## Other issues raised by respondents

4.76. Other substantive points raised in the responses include:

- **Model input assumptions:** Many respondents expressed the view that the modelling approach was generally appropriate, but some parties raised concerns that some of the input assumptions were, in their view, sub-optimal or erroneous.
- **Modelling parameters:** Some respondents raised concerns that some of the modelling parameters were sub-optimal. For example, a number of respondents were dissatisfied with the configuration of some aspects of the charging options

modelled, or the extent to which we had sufficiently quantified and assessed certain impacts.

- **Wider interactions:** A small number of respondents who commented on the analytical approach adopted and our interpretation of the results expressed the view that the CBA of the policy options was too narrow and/or did not sufficiently explore relevant interactions with other major policy or legislative developments.

4.77. Further detail of the views expressed by respondents, and our response in each of these areas, is summarised in appendix 1.

# 5. Our conclusion

5.1. This chapter sets out our conclusions of the SCR.

## Overview

5.2. Based on the evidence collected and our assessment of it, we have decided to confirm the position set out in our December 2011 consultation and direct industry to develop further and propose an improved form of ICRP.

5.3. We consider that it is appropriate to conclude the SCR now and direct that further work should be carried out by industry to refine this approach. Given that much of the work has already been done, we think that the technical expertise that resides in the industry governance process is best placed to progress this work and consider alternatives that best deliver the Project TransmiT objectives and drive further benefits to consumers in conjunction with developing the detailed changes to the CUSC. We expect the proposals developed through the CUSC process to be supported by a robust cost benefit analysis.

5.4. This decision will not result in any changes to transmission charges at this stage but will start an industry led process to further develop an improved form of ICRP through the CUSC process.

5.5. For the avoidance of doubt, we do not expect the industry process to consider a socialised option further.

5.6. Our detailed conclusions are summarised below.

## An improved ICRP type approach

### Dual background

5.7. The current ICRP methodology seeks to derive TNUoS tariffs that reflect incremental transmission costs. The existing model applied by NGET (the Transport Model) estimates how flows on the network change with incremental changes to generation and demand for each point on the network[32]. This uses only one background to reflect the assumption that all generation is equally likely to be running at system peak.

[32] In general, generators' charges are positive and demand charges are negative for areas which export power, and the converse is true for areas that import power.

5.8. The use of a loadflow model is robust if the incremental flows identified closely correlate with the resultant costs. The impact of this would be to promote more efficient decision making by parties using or considering using the transmission system. If, however, the relationship between costs and charges is more complex, then the retention of the existing ICRP methodology could have the effect of blunting the signals relating to the need for incremental requirements at particular points on the network (and therefore the underlying costs of providing transmission capacity for different users at different locations). This would lead to a sub optimal relationship between costs and charges for different users.[33] Over time, this would distort decisions on the closure of existing plant and the siting decisions of new plant and the costs associated with the operation of the network, leading to inefficiency more generally.

5.9. We will therefore direct NGET to further develop an improved form of ICRP that recognises the dual background approach of the recently modified NETS SQSS.

**Use of load factor**

5.10. We will direct NGET to require further exploration of exactly how the year round condition might best be structured and levied, so as to reflect accurately the incremental costs of transmission from a particular plant on the costs of efficient year round operation of the transmission system. This work will need to be informed by analysis of the relative costs and benefits of infrastructure investment as against operational expenditure, including, but not limited to, consideration of the following options:

- Ex-ante:
    - TEC x generic historical load factor for plant type
    - TEC x background generation scaling factors within the SQSS only
    - TEC x specific historical annual load factor.
- Ex-post:
    - TEC x requested load factor plus cash out reconciliation
    - TEC x ex-post MWh.

5.11. The industry's assessment would need to include whether the proposals:

- Better reflect the impact of different transmission system users on network investment and the incremental cost of transmission reinforcement.

- Improve the accuracy of charges for different users (e.g. between high and low load factor plants) across all areas of the network.

[33] Windfarms have traditionally expressed the view that that they are not capable of exporting to full capacity reservation due to the nature of their technology, and that a uniform scaling of all generation to meet demand overstates the likely contribution at system peak of intermittent generation, and is "biased" in favour of conventional plant. The argument is that appropriate scaling factors should be applied to generation reflecting their ability to meet peak demand, in particular renewable generation.

- Better achieve the relevant objectives, including a more favourable impact on consumers' bills in the medium to long term.

- Give due regard to the need to contribute to sustainable development including the achievement of legally binding commitments and long-run sustainability goals.

**Use of 5-year historical ALF to derive a locational signal**

5.12. We accept that there are arguments in support of both the actual and deemed historical output[34], and conclude that this should be considered in the CUSC process along with the related points such as the historical period on which to base a potential load factor calculation.

## Treatment of islands

**Unit cost equalisation**

5.13. No evidence was provided in support of the view that it is appropriate to introduce arrangements to artificially reduce to an arbitrary level the degree to which the prevailing methodology seeks to reflect the costs of different circuits and voltages.

5.14. Given the wider variability of high costs between proposed island links and the lack of data and experience of this technology at this time, we consider that an averaging approach and the application of a generic expansion factor across all potential links could inappropriately dilute the cost reflectivity of the resulting island tariff compared to a case-specific factor. We remain of the view that deriving an expansion factor using actual cost data is not an inappropriate modelling approach.

5.15. The industry-led process should however seek to investigate the practical ability to introduce a generic cost approach for the proposed island links upon which to utilise in an applicable expansion factor calculation. This work must not set unintended precedents when developing policy.

**Application of a year round tariff element**

5.16. While we consider that the justification provided for the treatment of potential islands links under the form of Improved ICRP modelled could be appropriate, we note that there are alternative approaches that merit further consideration as part of the industry process.

[34] We note that Redpoint have separately confirmed that the annual load factors used in the calculation of the year round tariff element under the modelled form of Improved ICRP were unconstrained and therefore the equivalent of Final Physical Notifications rather than metered data. This is consistent with the discussions of the technical working group on this topic.

5.17. Extending the onshore transmission charging arrangements to islands would seek to reflect the following characteristics of the islands:

- The capital cost of the transmission links compared to other parts of the network (noting that they are subsea cables spanning long distances).
- The variation in size, cost and design of potential links.
- The amount and type of generation in any new charging zones.

5.18. We will direct NGET to further consider whether it is appropriate to refine the arrangements on the dual wider tariff elements, and in particular whether the applicable generator locational tariff calculation for generators utilising potential island links should be consistent with the proposed application to the established mainland system (i.e. wider network tariff).

5.19. Any principles developed through the industry process should fall within universal principles that will be enduring and would therefore have to be carefully considered to ensure that the arrangements would not apply unintentionally to other circuit links where it would not be appropriate to do so.

**Treatment of island security factor**

5.20. We remain of the view that is appropriate to reflect the reduced security that potential generators locating on the islands groups when connected via a potential island link consisting of significant sections of single circuit would receive, i.e. a security factor of 1.0 should be applied to those assets.[35] We conclude that the proposed treatment of this should be considered in the CUSC process (i.e. islands with single circuit sub-sea connections).

## Treatment of HVDC 'bootstrap' converter station costs

5.21. We conclude that the proposed treatment of HVDC converter station costs that parallel the AC network in the expansion factor calculation should be considered in the CUSC process. This work will focus on establishing whether HVDC converter stations used for links are intrinsically linked to a specific line and are fundamentally locational in nature. This work should also seek to include an assessment of the materiality of all associated benefits (e.g. utilisation, system operation and strategic sustainability benefits) where possible.

5.22. This work must not set unintended precedents when developing policy, especially in relation to the existing treatment of HVDC converter station costs

[35] The methodology will reflect this in a potential zonal tariff calculation by modifying the expansion factor applicable to this section of single subsea 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 subsea link included as part of the wide network.

endorsed by the Authority under previous charging decisions (GB ECM-08 and ECM-24[36]) and reflected in 14.15.50 in NGET's TNUoS Methodology Statement. We require further exploration of the issue through the amendment process. The industry-led process should therefore seek to group similar assets together where practical and appropriate, and clarify variances in treatment where they can be practically differentiated and justified. This also applies to the treatment of island links that use radial HVDC technology.

5.23. We conclude that the proposed treatment for determining electrical impedance[37] from an HVDC power flow should be considered in the CUSC process. We note the working group consensus to calculate the average ratio of total network boundary rating versus HVDC link rating for all boundaries that the link crosses.

## Split of revenue recovery (the G:D split)

5.24. We remain of the view that it is not necessary to alter the G:D split at this stage and that NGET should keep this issue under review and make proposals for change as and when necessary through the normal amendment process. As part of this process we expect NGET to consider the EU Tarification Guidelines and the impact on trade between Member States.

[36] para 4.30 of NGET's conclusions report ECM-24.
[37] Electrical impedance is the measure of the opposition that a circuit presents to the passage of a current when a voltage is applied. The Transport model derives a pattern of flows based on network impedance. HVDC links are not currently catered for in the Transport model.

# 6. Next steps

6.1. This document focuses on the electricity transmission charging issues that we have considered under the TransmiT SCR process. It also signals the end of the SCR and initiates an industry led process to further develop the charging methodology. Our decision will be given effect by issuing a direction to NGET to raise an amendment proposal under the CUSC which we plan to do later this month.

6.2. It is important to note that while this signals the end of SCR component of Project TransmiT, it does not signal the end of the process or our involvement. The SCR direction will initiate the CUSC governance process, which will involve a further stage of industry led work and consultation before a final CUSC amendment report is sent to us for consideration. As part of this assessment, parties to the CUSC will be able to suggest alternatives that would provide potential improvements to the current methodology in a manner consistent with the Project TransmiT principles for us to assess.

6.3. The CUSC panel will send an amendment report to us once the industry process has run its course. This will set out the panel's recommendations on the proposal(s), and any alternatives, and provide evidence assessing these amendments against the relevant objectives of the CUSC. Industry will decide the manner and timing of the industry process, but we note that the standard CUSC process to advance and develop amendment proposals takes approximately six months to complete. We note that there is scope for this to be extended if necessary to allow further assessment and consultation of the issues within the charging methodology that we have identified. However, we continue to urge industry to expedite this process and submit a final CUSC amendment report, with all the requisite justification and evidence, in a timely manner to ensure benefits are realised as quickly as possible.

6.4. Ultimately, our role is to consider amendment 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 amendment proposal.

6.5. In March, we identified an issue with an element of the modelling results presented in Redpoint's report. Additional investigations required Redpoint to undertake more work. This work was preliminary and high level and did not impact on our conclusions. However, we will make the paper they produced as part of this available to the CUSC working group in any event.

6.6. We understand that making the model available to the CUSC working group process might be helpful. We are currently unable to publish the model itself because it contains Redpoint's intellectual property. To facilitate access to the model we are happy to waive our copyright over the model so that external parties can access it with agreement from Redpoint – this is a matter for these parties and Redpoint to resolve if they wish to pursue this path. In particular, if NGET would find using the model beneficial as part of the process we encourage them to engage with Redpoint.

# Appendices

**Index**

# Appendix 1 - Summary of Responses

1.1. Our December 2011 consultation asked respondents to consider our assessment of the impacts of each of the options and our initial views of the way forward. We received 47 responses to the consultation.

## Responses to the consultation questions

1.2. Our December consultation asked respondents to consider seven primary questions which corresponded with the two general themes of our analysis: i) four questions concerned with our quantitative modelling work, our cost-benefit analysis of the charging options, and how they interact with other policy initiatives; ii) three further questions dealing with our wider sustainability assessment, and the potential treatment of new HVDC technology within the charging arrangements. As a general point, the vast majority of respondents were generally satisfied that the modelling approach taken, the cost-benefit analysis of the charging options and the assessment of the relevant policy interactions, was broadly appropriate.

1.3. The following sections summarise the views received in response to each question.

**Chapter four**

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

- Many respondents signalled they were generally satisfied that we have appropriately identified and where possible quantified the impacts of the Project TransmiT options.
- Notwithstanding this, respondents also noted aspects or specific impacts of the policy options that they considered had not been sufficiently identified or quantified, in particular::
    - A need for further consideration or quantification of non-cost elements e.g. environmental impacts, community benefits, risks of not meeting targets, *etc*.
    - Concerns about the accuracy or validity of certain input assumptions or certain modelling parameters e.g. costs associated with particular generation types, modelling of transmission reinforcements, constraint costs, *etc*.
    - Concerns that the full range of potential consumer impacts have not been fully quantified.
    - Concerns about the use of ALF, how it is derived and its efficacy in cost targeting.

  - Concern that there is insufficient analysis of the effects of the treatment of island links in the modelling and the potential impact it could have on island-based generation.

*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?*

- In their responses, many/most respondents noted additional impacts they believed we should take into account in the decision-making process. These included:
  - More analysis or greater consideration to be given to transitional issues e.g. appropriate lead times for suppliers to incorporate changes into customers' contracts in a timely manner which minimises disruption and transaction costs.
  - Under Improved ICRP, more analysis of the impacts on zones with little diversity of plant type i.e. zones dominated by renewable or conventional plant.
  - Further exploration of re-distributional effects, such as the consequential effects of having winners and losers e.g. unexpected plant closures.
  - Reconsideration of the proposed treatment of island generation in the charging arrangements, both in terms of its potential effects on island-based generation, and island communities more broadly.
  - Deeper, more granulated, analysis of consumer impacts e.g. more localised analysis of fuel poverty.

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

- A number of respondents intimated they were broadly satisfied we had appropriately identified the potential interactions of the charging options.
- Nonetheless, some respondents identified a range of potential interactions which they believed had not been considered, or those which could have been explored in more detail in our analysis. These issues primarily related to the following areas:
  - Insufficient 'stress testing' of the charging options and their potential interactions or consistency with the EMR, review of SQSS, RIIO or EU developments.
  - The proposed treatment of island links in the charging arrangements and its consistency with EU legislation.
  - The interactions with support mechanisms (e.g. ROCs, FiT, CfD) have not been assessed with sufficient depth or rigour.

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

- Several respondents noted they were broadly happy that we have appropriately identified the likely impacts and consequences of the interactions within the charging options.
- However, some respondents noted aspects of the likely impacts and interactions of the charging options which they believed had not been adequately identified. These broadly related to the following two areas:
    - Requirement for more in-depth or greater disaggregated analysis of the impact of each charging option on different generation types, or more analysis of potential location shifts.
    - Requirement for more detailed analysis of the potential effects of charging options on island generation, including the legalities of the proposed island treatment.

**Chapter five**

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

- Some respondents intimated they were, by and large, satisfied we had appropriately identified and taken account of the key sustainability issues.
- Conversely, slightly more respondents noted aspects of the sustainability analysis which they believed had not been sufficiently considered. These areas of concern generally fell within the following categories:
    - Greater analysis of ecological impacts of each charging options required.
    - Greater consideration and quantification of the potential economic and environmental benefits of exceeding renewable targets required.
    - Benefit in further investigating the impacts and interactions within each charging option in relation to their effects on the development of renewable technologies e.g. energy storage.

*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?*

- The vast majority of respondents who commented on this question supported the development of HVDC technology, noting the long-term strategic benefits it could potentially offer in principle.

- At the same time, several respondents also expressed caution in developing new HVDC technology either because of its expense, or because they believed its necessity as a means of reinforcing the onshore AC network in the near-term had not been convincingly proven.
- With regard to the potential treatment of HVDC technology in the charging methodology, opinion was split between those who favoured the socialisation of HVDC converter station costs, and those who favoured recovering the costs through the locational element of the charge.

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

- No evidence for any specific treatment of converter station costs was submitted.

## Respondents' views on the modelling approach

1.4. The majority of respondents were generally satisfied that the modelling approach taken, and the assessment of the relevant policy interactions, was appropriate.

1.5. Many respondents also commented positively on what they perceived to be the extensive and transparent nature of the stakeholder engagement and modelling work conducted through the TransmiT process to date. Notwithstanding this, a number of respondents expressed the view that there was a lack of opportunity to interrogate the input assumptions and stress test the impacts of the charging options. These respondents' went on to highlight areas where they considered certain aspects of the modelling work, or our interpretation and consultation of the cost-benefit analysis, could have been improved. These views can be broadly captured within the following three categories:

- Model input assumptions.
- Modelling parameters.
- Wider interactions.

1.6. The next sections set out a high-level summary of responses in each of these areas and our views on the issues raised.

*Respondents' views on model input assumptions*

1.7. Many respondents expressed the view that the modelling approach was generally appropriate, but some parties raised concerns that some of the input assumptions were, in their view, sub-optimal or erroneous, in particular:

- General cost and load factor assumptions are too simplistic, particularly offshore, and lead to an overestimate of costs across each of the charging options.
- Capital costs assumptions for transmission expansion, and for certain transmission reinforcements are understated. For example, the ICRP model uses an assumption of ~£11.5/MWkm for generic incremental reinforcement, which is less than that used in the NETS SQSS analysis.
- Unrealistic assumptions are used for power station build (e.g. 5 year timescale for nuclear plant), which are likely to lead to an unrealistic generation background
- 50g/kWh, not 100g/kWh is the 2030 goal at which the modelling should have been set.

*Ofgem views*

1.8. We note the detailed and constructive debate on the issues of cost and other operational assumptions throughout the technical working group and consultation process. The analysis conducted for Project TransmiT had the objective of comparing different charging options on costs, sustainability and security of supply. This in turn required a review of all the potential new generating stations across GB, differentiated by technology and location. Creating this project resource dataset for the whole of GB in reasonable timescales required set limits on the level of detail that was appropriate for general projects. However, care was taken to ensure that Redpoint's modelling exercise was based on the best publicly available data sources (see appendix B of Redpoint's December report for more information), and this was largely driven by input from industry.

1.9. Our response to each of the individual comments is set out below.

- We acknowledge that further granularity is possible, and accept that a further level of detail might change deployment of specific projects across the time horizon for each of the three charging options. However, we do not consider that changes to the inputs of particular projects are likely to substantively improve the accuracy of the modelling results for the purpose of comparison of charging options.

- It is also important to clarify that the modelling exercise was not a comment on the financial viability or strength of specific projects; there are bespoke factors which could not be reflected in Redpoint's modelling work that would be taken into account for an individual project appraisal.

- In our view the level of detail was the best representation of current factors that Redpoint could produce in reasonable timescales and was appropriate for the requirement of the modelling exercise. We would stress that the analytical model is organic and could evolve to better account for investment and generation characteristics and reflect better information, if such was made available, for instance, in the CUSC process.

- In response to the concerns raised about the cost of transmission expansion, it is important to first clarify that the full magnitude of any increases in transmission reinforcement costs was included in the calculation of power sector costs in the modelling exercise. We also note that within the charging model applied by NGET all transmission circuits are treated equally (despite actual networks comprising different circuits and voltages). To ensure such equality NGET makes a number of adjustments to the physical circuit lengths for modelling purposes. The adjustments are made by applying expansion factors based on estimates of costs of different circuits compared to the average unit cost of the most efficient medium to transport electricity in unit cost terms (i.e. 400kV overhead line circuits). Hence, it is clear that actual system reinforcement will have a range of costs which when converted into expansion costs will be different from the expansion constant used in NGET's charging model (currently £11.14/MWkm). We recognise that a single expansion constant will not represent the actual cost of expanding a particular boundary, but consider it to represent a suitable approximation that is consistent with ensuring that appropriate electricity transmission charging arrangements are in place.

- Furthermore, we note the constructive debate on the issue of the unit cost of transmission capacity in the technical working group and the conclusion not to propose adjustments for the modelling exercise. Given the lack of quantitative evidence provided in support of an increase in the costs of expansion, we remain of the view that this aspect of the modelling exercise is robust.

- In terms of plant build assumptions, we note that lengthening the assumed years for nuclear planning and build, for example, would lead to a significant delays for the first new nuclear generators compared to the published TEC dates. We remain of the view that the build assumptions, based on the best publicly available data sources and consulted thoroughly with stakeholders, are the best representation that Redpoint could produce in reasonable timescales. We also note that those respondents that disagreed with this general approach provided no quantitative evidence in support of their view that the assumptions underpinning the current unit cost approach are unrealistic.

- Some parties questioned the choice of a five year look ahead in the modelling of generator new build decisions, raising a concern that the profitability of a generator is not reassessed during its lifetime. In response, we note that a major driver of profitability for low carbon generators will be the level of CfD that the plant is entitled to. The modelling exercise illustrates that revenues do not diverge from expectation over the lifetime of the projects. For new thermal generation, the profitability assessment at project commitment includes capital costs. After construction these costs are sunk and therefore the decision to stay open or close should be based on the recovery of fixed costs. Furthermore, given the efficiency advantage of a new CCGT plant, these new generators will be expected to operate more and achieve a better margin than existing generators. Existing generators would therefore close first, and an assessment of their profitability is made in the modelling exercise should they choose to retire.

- We note that a carbon reduction figure for generation of 50 g/kWh was recommended by the Committee on Climate Change (CCC) in its 4th Budget Report, which the government recently accepted (2023-2027), but remain of the view that a level of 100 g/kWh is credible given that this level was assumed in the analysis supporting DECC's EMR consultation.

*Respondents' views on modelling parameters*

1.10. Respondents raised concerns that some of the modelling parameters were sub-optimal. For example, a number of respondents were dissatisfied with the configuration of some aspects of the charging options modelled, or the extent to which we had sufficiently quantified and assessed certain impacts. Areas of concern include:

- Deficient modelling parameters for the charging of offshore links, particularly R3 sites.
- Distributional effects insufficiently quantified or assessed.
- Deficient modelling of constraints and their interactions with transmission reinforcement.
- More variants of the 'base case' charging options for Improved ICRP and Socialised could have been explored, e.g. Long Run Incremental Cost (LRIC).
- Deeper analysis of consumer impacts required, particularly on the link with Fuel Poverty.
- Limited number of sensitivities modelled. A common suggestion was a sensitivity to reflect the significant potential for cost reductions in offshore wind (e.g. £100/MWh cost reduction target being met by 2020). Another suggestion was to re-run the analysis once Contract for Difference (CfD) levels are known to ensure that the 2020 targets will still be achieved.
- Planning constraints have been underestimated, resulting in overstated build in the south.
- Doubts on the reliability of the modelling on costs to consumers, particularly the lack of convergence in the generation background under Status Quo.
- Issues with tariff uncertainty under a cost reflective approach, highlighted by the range of credible tariffs produced by Redpoint, and tariff stability under a socialised approach, have not been adequately modelled.
- Issues with year-on-year charge volatility that would result from the adoption of the specific form of the Improved ICRP have not been adequately modelled.
- The results are highly sensitive to changes in fuel prices, and the indicated magnitude of some cost movements may be statistically insignificant.
- The use of power sector costs as a welfare measure is inherently flawed. There is no confidence that the energy market is operating effectively.

*Ofgem views*

1.11. A specific criticism expressed by some parties was that the modelling parameters for the charging of offshore links are flawed. We note that this appears to be a reference to the relative profitability ordering of sites within the model.

1.12. It is important to again stress that the modelling exercise was not a comment on the financial viability or strength of specific projects. We also note that the modelling does not assume that developers change sites, as one respondent suggested. Instead, the modelling exercise was constructed such that when the CfD strike prices are reset (to reflect the change in TNUoS, which is seen to cause a change in the relative profitability ordering of sites to change) a different set of sites will be profitable, i.e. different Round 3 zones may be developed by their different developers.

1.13. We do recognise, however, that there are valid reasons for updating the current methodology and that this should continue to be explored through the CUSC process.

1.14. Many respondents sought greater clarity on the redistributional impact which is likely to result from a change in the charging methodology, and an understanding of how such risks might be managed. The modelling assessment conducted by Redpoint was based on the impact against three broad factors; sustainability, security and cost. The redistributional impact on security of supply has been picked up through changes in retirements of existing plant. However this is also affected by the assumption of the Capacity Mechanism. The adoption of a simplified mechanism within the modelling exercise was discussed with industry. The mechanism itself provides the additional revenue required by the marginal capacity, which could reduce the effect of transmission charges on security of supply.

1.15. The redistribution of money between existing generators was presented in the modelling results in Redpoint's report but for reasons of brevity was not split out into zone or plant type. The breakdown was however included in Ofgem's December 2011 consultation in Appendix 3. We also note that the information does exist in the zonal tariff data published in conjunction with Redpoint's December report and can be used to make a reasonable assessment of the distributional impact to existing individual generators.

1.16. We note that there was significant debate in the technical working group on the issue of reinforcement options available to alleviate constraints on the north-south power flows once the planned HVDC reinforcements have been constructed. Some expressed the view that conventional economic wisdom suggests that if constraint costs become excessive then transmission reinforcements would naturally increase to find a more optimal balance between constraint and reinforcement cost. However the analysis seems to indicate that constraint costs remain high, especially under a socialised approach, which some did not believe was a credible outcome.

1.17. As noted in the working group discussion, the modelling exercise has explicitly taken account of all prospective reinforcement projects and has also assumed additional generic reinforcement options on every boundary modelled (Table 26 of Redpoint's December report). For the key Scottish boundaries there are additional reinforcements of 1GW available on each boundary. On the information available, we consider that these projects represent a credible representation of the potential available reinforcement projects for the purposes of our modelling exercise.

1.18. If there were further additional reinforcements available then it is likely that the reduction in constraint costs would outweigh the cost of the reinforcements and we would see some additional savings. However according to the results of our modelling exercise, the likely level of reinforcement, especially under a socialised approach, would represent a high level of investment, in which case further reinforcements would become highly speculative. Consequently, we remain of the view that the modelling exercise identified credible outcomes for constraint costs across the various options and that despite delivering all possible reinforcements in an economic and efficient manner the constraint costs are likely to remain high under a socialised approach. We also note that the level of constraint costs obtained through the modelling has no impact on the modelling results to 2020.

1.19. We note that the analysis to date has so far modelled and considered fully only one form of Improved ICRP (and a variant). We recognise the need to consider a wider range of options for improvements than the version modelled. We do not consider that such further work should consider the adoption of alternative charging approaches (e.g. LRIC). The technical working group discussion highlighted that a basic distinction between a charging methodology based on the LRIC model and the ICRP approach is the time horizon over which you calculate locational charges. A particular concern of the LRIC model and its application at a transmission level is the imposition of the full cost of an enhancement of transmission capacity on a single user. It was noted that this characteristic has the potential to increase the volatility and complexity of charges levied on users. While such issues are not insurmountable, we do not feel that consideration of a LRIC based methodology represents the most appropriate means of addressing the issues that are the immediate priority of this SCR.

1.20. We agree with the view of some respondents that further analysis is required on the consumer impacts of potential reform. This should continue to be explored through the CUSC process.

1.21. We agree that suggestions for further sensitivity analysis are sensible e.g. to reflect further information on the subsidy levels reflecting developments in the EMR process. We note that the extent of the modelling exercise was largely driven by the need to establish the most appropriate method of addressing particular concerns raised by stakeholders that were an immediate priority within a reasonable timescale for the SCR process.

1.22. A common criticism was that the modelling exercise has not taken account of the potential for significant cost reductions in offshore wind to £100/MWh (the Renewables Roadmap target). We note that Redpoint did explore this point. Their work in this area looked at the outputs for the year 2020 in the modelled form of Status Quo and Socialisation in the context of the Stage 2 results. In 2020, the modelling published in December indicates that there is approximately 2.7GW more offshore wind under a socialised approach, equating to ~8.8TWh additional generation from offshore wind. The decrease in power sector costs in 2020 is close to £1.5bn. Redpoint calculated that the levelised cost of the additional offshore wind would need to be in the region of £160/MWh lower for the two options to give equivalent power sector costs in this year. Given that the average levelised cost of offshore wind is around £130/MWh in 2020, Redpoint conclude that there is no credible scenario of offshore wind costs in which Socialised costs would match Status Quo in that year. Hence, the application of a levelised cost in 2020 of £100/MWh for offshore wind would still be expected to deliver a very high power sector cost increase.

1.23. We note that there was debate in the working group on whether the modelling approach should have considered the impact of over compensating renewable generation relative to its impact on carbon saving. We note that the majority of Renewables Obligation Certificates (ROCs) wind is grandfathered and changes in TNUoS tariffs (and other price movements) cannot be taken into account through changes in the subsidy level. The modelling exercise considered the change over to CfDs as occurring in 2014 – therefore little additional wind is built under the RO and what is built is based on the proposed onshore wind banding (0.9 ROCs/MWh published in October 2011). Under the Stage 2 approach, CfD strike prices are adjusted to ensure that each charging option meets the same renewable target. This tends to equalise levels of 'rent' although there are differences across options.

1.24. We recognise that assumptions on planning timescales are important to the modelling exercise. Based on the evidence provided, it is not obvious that there are other additional planning limitations that the modelling should take into account.

1.25. We consider that doubts raised by some respondents on the reliability of Redpoint's modelling of the costs to consumers are based on a misrepresentation of the Perfect Foresight modelling. It is correct to note that different outcomes are possible but this is true of all scenario based modelling.

1.26. We disagree with the suggestion that the modelling has not adequately reflected the issue of tariff uncertainty under the modelled form of Status Quo and Improved ICRP. It is clearly true that tariff levels under any form of ICRP approach will show more year to year variation than under a socialised approach and are exposed to step changes when large, expensive capital projects are commissioned (e.g. bootstraps). We consider this concern to be based on a misunderstanding of the Perfect Foresight modelling approach. The key point about a Perfect Foresight approach is that generation investment decisions are no longer consistent with the tariffs (hence the generation investment decisions change on the next iteration). Therefore it is not possible to draw the conclusion that a credible range of tariffs is given by a range in the tariffs between iterations, or the conclusion that the perceived uncertainty created by such differences has not been modelled.

1.27. We also note that uncertainty in generator TNUoS charge levels is true in all charging options. While the modelled form of Improved ICRP has more parameters this does not make it necessarily more uncertain – in fact the modelling suggests that tariffs are less prone to large year on year movements than under the modelled form of Status Quo.

1.28. We note the related view expressed by one respondent that a Perfect Foresight modelling approach provides a coherent conceptual framework, but suggested that a lack of convergence highlighted a failure in Redpoint's modelling approach. In response, we note that the Perfect Foresight approach adopted by Redpoint used iterations between tariff calculations, generation investment decisions and transmission investment decisions. For each component the full horizon was run, keeping other components static. This means that an iterative approach is required. We note that non-convergence is not a failure of the model. There is no theoretical reason why the model should converge in all cases, particularly where transmission investments decisions are "lumpy" (i.e. not always matching the changes of generation and demand charges).

1.29. We agree that an assessment of the volatility of tariffs should be taken forward as part of the further work by industry to refine the Improved ICRP type approach.

1.30. Redpoint's report suggests that the results indicate that Improved ICRP is broadly neutral with Status Quo with respect to power sector costs. The issue of statistical accuracy does not change this general view.

1.31. Regarding the criticism of power sector costs as an effective welfare measure, we note that both power sector costs and consumer bills have a role in the evaluation of policy. Power sector costs can be used as a measure of welfare as they represent the change in total cost to the economy of meeting electricity demand. Consumer bill results are more dependent on the design of market arrangements.

*Respondents' views on the assessment of potential wider interactions*

1.32. A small number of respondents who commented on the analytical approach adopted and our interpretation of the results expressed the view that the CBA of the policy options was too narrow, too shallow, and/or did not sufficiently explore relevant interactions with other major policy or legislative developments. Areas of concern include:

- Deficient treatment of socio-economic benefits that renewable energy projects would bring to the Scottish islands.
- Interactions with support mechanisms not assessed in sufficient depth.
- Insufficient exploration of the detrimental impacts of altering the locational spread of charges to both security of supply, i.e. more capacity in constrained areas of the system and the likelihood of increased costs in the South causing some plant to be closed sooner than planned.

- Insufficiently disaggregated analysis of the impacts of each option on different renewable technologies e.g. wave and tidal.
- Failure to address wider issues of sustainability, such as the impact on biodiversity.
- No monetary benefit has been attached to the risk of not achieving the renewable targets or to the increased probability of achieving these targets.
- The impact of Improved ICRP on wholesale costs is overplayed.
- It is not clear how the impact on the merit order of gas plants has been modelled.

*Ofgem views*

1.33. We recognise that there are important interactions between transmission charging and the levels of support that different forms of low carbon generation require in order to be built. We note that the UK government has yet to set the level of support (in the form of 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. Redpoint's modelling therefore assumed 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.[38]
- 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.

1.34. To capture these different effects, a simplified interaction between TNUoS and low carbon support was used in the modelling exercise. We therefore consider that comments received on the interaction with support mechanisms are therefore more relevant to EMR policy design and implementation.

1.35. We note the concern that the detrimental impacts of altering the locational spread of charges to security of supply. In response, we note that the modelling exercise did take into account the impact of tariff changes on generator profitability and therefore potential closures (made on an economic basis). The differences are potentially limited by the influence of a simplified Capacity Mechanism. We note that the actual mechanism that will be implemented will most likely be different from the version applied in our modelling exercise and therefore an assessment of the impact of the mechanism on specific forms of technology could not currently be completed. There is no theoretical reason to consider that the modelled form of Improved ICRP will lead to a drop in the capacity margin.

[38] In accordance with the UK government's Renewable Energy Strategy.

1.36. We note the view expressed by some respondents that a potential consequence of reduced exposure to TNUoS under the modelled form of Improved ICRP is that there may be additional costs associated with extending the life of current low efficiency plant located behind an export constraint. In response, we note that the modelling exercise has assumed that additional costs of life extensions for any thermal plant are captured in the annual fixed Operation and Maintenance (O&M) costs of the plant. Such lifetime costs can be assumed to be similar between generators of the same type and similar age.

1.37. We agree that further consideration is required of the impacts on different renewable technologies. Throughout our review, we have explicitly incorporated consideration of the prevalent renewable technologies in across GB (including Scotland and the islands) such as wave, tidal and wind generation that are seeking connection and they are fully incorporated in our modelling to date. For wave and tidal in particular, we note that we are at a very early stage in a potentially new industry and there are a lot of uncertainties around the way in which the technology would unfold in the future, and that transmission costs are just one element of cost to be considered in the development decisions of generation technologies.

1.38. Regarding the impact on biodiversity, we consider that such considerations are better considered in the context of specific planning decisions.

1.39. We note the comment that no monetary value has been assigned to the risk of not achieving the renewable policy targets or to the increased probability of achieving these targets. However, we note that to assign such a value/cost would require two further components; (i) the cost of not meeting the relevant renewables target, and (ii) the change in probability of doing this under each charging option. In terms of point i, we consider that only DECC could provide such a value. Regarding the probability of not meeting the target, it is well understood that a scenario based modelling approach does not lend itself to assigning probabilities to specific outcomes. It also seems highly unlikely that a monetary value would exceed the corresponding costs of a socialised charging approach.

1.40. The wholesale price impacts indicated by the Redpoint modelling exercise are consistent with the capacity mix that develops under the modelled form of Improved ICRP. We do not agree with the comment that the impact on wholesale costs is overplayed.

1.41. Regarding the merit order of gas plant, our modelling has included the carbon floor price, using the central trajectory published by HMT in December 2010. There is no obvious reason to suggest that the modelled form of Improved ICRP will lead to a change in the merit order of gas plant (relative to each other) of the carbon price changes. Increases in the carbon price will have the effect of "stretching" the supply curve but the order of CCGTs would not change. To expand this point slightly, we do recognise that an increase in the carbon price could change the merit order of coal and gas. The Low Gas Sensitivity explicitly tested this scenario. The modelling indicated a reduction in constraint costs cause by greater generation from CCGTs in the unconstrained run. Relative to coal plant, these CCGTs are located outside of the key export boundaries.

## Further comments

*Respondents' views*

1.42. One respondent commented that there are further modifications that could be considered and developed for implementation as part of the SCR process to address areas of perceived deficiency in the existing methodology. These areas included:

- The way in which the expansion constant is calculated and applied (discussed in chapter 4).
- The adoption of an uniform expansion constant (discussed in chapter 4).
- Flooring generator charges at a small positive charge.

1.43. One respondent noted that there is a clear disincentive with the Improved ICRP option to install large battery grid storage at the wind farm level.

1.44. One respondent expressed the view that the modelling exercise should have sought alternative views on costs associated with reinforcing and expanding networks, and HVDC links in particular, as they were of the opinion that the costs used are understated and lead to earlier transmission build timeframes.

1.45. Several respondents commented that the development of the European Target Model should be taken into account in any future charging decision, some suggesting that the current GB approach is inconsistent with the approach in Europe. A number of respondents also asked for clarification on the statement in Ofgem's December consultation that the modelled form of Improved ICRP "was consistent with the European direction of travel".

1.46. Some respondents with an interest in island development presented analysis in support of their case to find a solution to connecting the Scottish Islands beyond the current charging proposals. The central premise of this analysis was that island (onshore) wind can generate significant levels of low carbon generation at a lower overall cost to the consumer than other low carbon technologies (namely, offshore wind). The financial summary presented suggested that UK taxpayers will potentially be over £3bn "better off" in terms of subsidy payments over the 20 year life of 1 GW of island onshore wind compared with an amount of offshore technology attracting 2 ROCs with an identical load factor. The argument is then extended to the charging sphere by commenting that a substantial proportion of this potential benefit would remain (~£1.8bn) when combined with a modified version of a socialised charging approach for potential island links (i.e. the remaining £1.2bn would be transferred to island generation over the assumed 20 year period).

1.47. Several comments expressed a strong opinion on the need for robust transitional arrangements. The following points were made in relation to this issue:

- The CUSC working group must be instructed to develop appropriate transitional arrangements (e.g. TEC reduction closure notifications).
- Ofgem should direct implementation of such changes at the earliest date subject to reasonable transitional arrangements.
- It is important that industry has a sufficient transitional period to incorporate any changes into their business plans, e.g. two full charging years.

1.48. One respondent commented that the lack of convergence in the Perfect Foresight modelling supports that conclusion that retention of status quo will lead to higher generation costs through the higher discount rate that will be factored into investment decisions.

1.49. Some respondents highlighted concerns regarding possible parallels between P229 and Project TransmiT, suggesting that waiting until EU tarification principles are clearer before implementing and developing a new charging methodology would be consistent with Ofgem decision to reject P229.

1.50. One respondent made the comment that Redpoint's modelling approach to energy security, based solely on a Capacity Mechanism, is too simplistic and far greater weight should have been given to demand side measures.

1.51. One respondent appointed an external firm of consultants (NERA) to review Redpoint's modelling framework. This report is available from the Ofgem website[39]. The following key points were raised:

i. Imperfect foresight does not constitute a coherent economic framework, and question the application of an arbitrary planning horizon of 5 years.
ii. Ofgem's characterisation of the Imperfect Foresight modelling approach appears incorrect.
iii. Ofgem's characterisation of the Perfect Foresight modelling is misleading and did not converge.
iv. Perfect Foresight modelling results do not support Ofgem's conclusions on the welfare implications of the alternative charging models.
v. NGET's ELSI model is not a reliable tool for forecasting the evolution of the GB power market.
vi. Redpoint's calibration exercise indicates significant differences between ELSI and the more detailed PLEXOS model.
vii. Redpoint's "uplift" function is not transparent.
viii. Adjustments to subsidy levels in Stage 2 modelling.

[39] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=180&refer=Networks/Trans/PT/WF

ix. Consistency of CBA with model results.

*Ofgem's views*

1.52. We note the suggestion that further work could be taken forward by industry to investigate the potential to floor generation charges at a small positive level, thus obviating the need for payments to any user. This effectively would involve a narrowing of the differential between locations. We note that the difficulty with such an approach, however, is that from the point of view of transmission this does not properly reflect costs imposed and will therefore not send the correct signal to users making locational decisions. The impact of this could be to promote less efficient decision making by parties and undermine the ability of the charging arrangements to meet the objectives of TransmiT or our wider statutory duties.

1.53. The use of battery storage at wind farm sites under the modelled form of Improved ICRP would impact on tariffs in the following manner. The year round tariff element would be unaffected, because the annual load factor of the wind farm would not change. The peak tariff element could change if it is judged that windfarms with battery storage would make a contribution in the peak background. If this policy choice were made, the windfarm would pay the peak tariff element. It is notable that the modelling exercise indicates that under Improved ICRP the peak tariff is negative where the highest year round tariff exists. This would actually provide a small incentive for battery storage.

1.54. In response to the comment that the costs of reinforcement are understated, we note that that Redpoint's modelling exercise was based on the best publicly available data sources (see appendix B of Redpoint's December report for more information) and was largely driven by input from industry. The cost of work to the onshore transmission network, including the planned HVDC reinforcement projects, has been estimated using public RIIO business plan submissions from the three Transmission Owners (NGET, SPT and SHETL). Further scrutiny of these figures will be taken forward through the RIIO process.

1.55. Regarding the development of the European Target model, we note that the modelling of options that imply wider changes (e.g. to the GB market arrangements, such as market splitting) were explicitly excluded from the scope of the Project TransmiT modelling and SCR process. We also note that a locational charging signal is the underlying concept behind the EU's single market policy thinking and that of the three charging options we have modelled to date only the socialised approach is inconsistent with this. Work is being progressed separately within Ofgem on potential market splitting options to assess the potential impact on the GB market moving forward as this is also central to the EU's ambitions for electricity market reform. Our European strategy team recently published an open letter entitled "Implementing the European Electricity Target Model in GB"[40] inviting views,

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[40] Published on Wednesday, 28 March 2012.
http://www.ofgem.gov.uk/Europe/Documents1/EU%20Target%20Model%20open%20letter.pdf

amongst other things, on the changes need to GB market arrangements to facilitate market integration.

1.56. As the analysis presented by some respondents highlights, the level of external support to renewable generators though the RO scheme vary by technology, according to a number of factors including their costs. The RO scheme is designed to ensure that the subsidy mechanism does not pay more than is necessary to meet the deployment needed to meet DECC's legally binding target. The mechanism therefore seeks to allocate subsidy to diverse sources to ensure a geographically dispersed, range of low carbon electricity generation technologies. Hence, encouraging users of the system to weigh the costs of transmission against other costs and operating efficiencies which are likely to vary by location will allow them to make informed decisions. A cost reflective charging signal will therefore assist in deterring poorly sited projects which are more expensive to develop. If this approach is not applied then the costs of poorly sited generation projects will be borne, ultimately, by all electricity consumers through their bills to recover the costs associated with the development of a network that is larger than it otherwise need be and by the GB taxpayer through exposure to payments made via an RO subsidy mechanism that is larger than it need be.

1.57. We are unable to provide detailed comment on the analysis presented indicating that island based onshore wind generation offers a more cost effective subsidy mechanism relative to an identical form of offshore wind generation. We do note that the logic is correct that the development of a particular generation technology that attracts a higher level of subsidy will incur greater costs on the subsidy mechanism than the cost of a different form of generation that attracts a lower level of subsidy payment. However, the extension of this logic to a charging discussion is not clear given that the level of subsidy is a matter external to Ofgem. We also note that the analysis does not consider the wider application of the subsidy mechanism, in particular the comparison of generation technology that imposes lower costs than island generation (i.e. alternative onshore wind sites).

1.58. Notwithstanding this, we acknowledge that renewable generators are frequently located on the periphery of the network and, as a consequence, it is relatively costly to connect them to the grid and transport power from them to the centres of demand. Even though it is more expensive to transport electricity over long distances to where it is consumed, Redpoint's modelling exercise adds to previous independent analysis[41] conducted by DECC in 2008 which concluded that it may be still economic to site generation in peripheral areas under a cost reflective charging approach. This position is supported by our modelling exercise.

1.59. We therefore remain of the view that even with an external subsidy regime, it still makes sense to have a charging regime that reflects the costs imposed by users at different points in the network to ensure that the consumer gets the best value by ensuring that efficient decisions are made between alternative locations for renewable generation.

[41] Available from DECC's website: www.decc.gov.uk

1.60. We note the comments on Redpoint's Perfect Foresight Modelling and the suggestion that a lack of convergence will increase the discount rate and lead to higher generation costs under the modelled form of Status Quo. We believe that this conclusion is based on a misunderstanding of the Perfect Foresight modelling. It does not follow that a higher discount rate should necessarily be used in investment decisions. It would need to be demonstrated that the risk on project returns is appreciably higher due to uncertainty of future TNUoS tariffs. The uncertainty may be swamped by other uncertainties such as construction risk, future wholesale market revenues and uncertainty on other fixed cost elements.

1.61. In relation to the comments received regarding the transition and implementation of any enduring solution identified by the CUSC industry process, while noting that industry will ultimately decide the manner and timing of the process to develop a modification proposal, we continue to urge industry to implement any appropriate changes as quickly as practicable after we issue our conclusions and formal direction. We believe that this approach should seek to ensure that any potential benefits are able to be fully realised by existing and future consumers as quickly as possible. However, we note that the CUSC process timetable will provide opportunity for respondents to both consider and comment on all aspects of the transitional arrangements (i.e. both generation and supplier concerns) in full on a GB basis.

1.62. We recognise, however, that in ideal circumstances users would be provided with more notice of final tariffs than has proven to be possible in the prevailing circumstances. Further action is available to NGET in the period after the conclusion of the SCR and CUSC amendment process to enable parties to manage the risks associated with tariff changes more efficiently, which in turn might be expected to facilitate competition further. Specifically, more information could be provided to parties as to the possible path of tariffs over time, and that work could be undertaken by NGET in consultation with industry to enable parties to develop appropriate transitional arrangements and secure modified arrangements (e.g. TEC reduction closure notifications).

1.63. The issue of locational losses (the subject matter of P229) is not part of the TransmiT SCR process. That modification proposal had a different process and its own considerations relevant to its particular context.

1.64. Comments on demand side measures to ensure energy security are more relevant to EMR policy design and implementation. We agree that demand side measures will have a role to play in the security of a decarbonised market, and that these should be taken into account in the design of a capacity mechanism. We do not believe that further demand side measures are key to the comparison between different transmission charging arrangements.

1.65. A brief response to each of the high level points raised in NERA's report is set out below.

i. Our modelling exercise has made a simplifying assumption that the discount rate is very large after 5 years. We think such an approach is reasonable for the purposes of the modelling.

ii. The model does simulate expected behaviour and will attempt to reflect that there is incomplete information about the future. Hence, the approach seeks to model how players react to various policy options assuming imperfect information about how other parties will react and a limited view on how future prices will develop.

iii. We note that our characterisation has no bearing on the validity or otherwise of the modelling approach and results. There is no theoretical reason why the model should converge in all cases.

iv. We note the difference in opinion, but consider that non-convergence is not a failure of the model.

v. The modelling approach produced good matches in the fundamental results between PLEXOS and ELSI, for example generation by plant type. We believe that the modelling choice was appropriate to the scope and timeframes of the work.

vi. Results for the generation and transmission background are run through the power market simulation tool PLEXOS for benchmarking of constraint cost forecasts. The modelling approach has always been clear about the simplification. We also note that NERA's concerns do not lead to any implications for the results in the 2011-2020 period.

vii. Redpoint calibrated the uplift function against historical market prices. General issues of calibration are common to any approach using historic data to forecast into the future.

viii. We note the difference of opinion, and note that the least cost minimisation approach suggested sounds credible. However, we believe that the modelling choice was appropriate to the scope and timeframes of the work.

ix. The difference between transmission costs in the power sector and the Demand TNUoS change under consumer bills is that transmission losses are included in the former but split out into a separate line in the consumer bills section. This is a purely presentational point. In retrospect it would have been clearer if the presentation of the modelling had split out transmission losses in power sector costs.

# Appendix 2 – Wider Sustainability Assessment

2.1. Our duties require us to have regard to the need to contribute to sustainable development. As part of our December impact assessment of the charging options we undertook a separate analysis of wider sustainability considerations – this was set out in Chapter 5 of that document. This involved considering implication of the different charging options for strategic factors (such as for diversity and optionality) and sustainability (such as policy or technological 'lock-in'[42], learning and supply chain development, and consistency with long-run sustainability).

2.2. This wider sustainability analysis we undertook reinforced our view not to pursue the socialisation approach to charging any further, because its lack of cost-reflectivity could result in locational decisions with higher economic and environmental costs without any corresponding benefits.

2.3. Our sustainability assessment reinforced the broad conclusion of our assessment of the impacts of the Project TransmiT SCR options (i.e. not to direct further consideration of socialised charging in this SCR) and provided clear support for an improved version of ICRP, which led to earlier development of key transmission assets and more development of renewable energy.

2.4. The modelling of Improved ICRP accelerated investment in the transmission system, including north-south HVDC 'bootstraps', and associated generation particularly in wind energy resources in the north. This, and reduced transmission charges to renewable sources in northern areas of GB, led to more renewable investment after 2020 which should also improve prospects for complying with the UK's 4th carbon budget[43].

2.5. The modelling and financial calculations did not extend beyond 2030 and thus it was not possible to assess the extent to which the larger near-term investment costs may be matched by longer term benefits, including the potential contributions to achieving the UK's 2050 Greenhouse Gas target.

2.6. The analysis did indicate that some variants within Improved ICRP may differ in their strategic and sustainability implications. HVDC development is likely to improve access of the entire system to the UK's large resources of renewable energy consistent with long-run policy goals of Government. In particular HVDC convertor stations (which form approximately a third of total HVDC costs) are a rapidly developing technology with potential system-wide optionality, learning and other sustainability and strategic benefits.

[42] 'Lock-in' refers to a scenario where a decision made today sets in train a trajectory which, by its very nature, potentially rules out certain future alternatives.

[43] A 'carbon budget' is a cap on the total quantity of greenhouse gas emissions emitted in the UK over a specified time. Under a system of carbon budgets, every tonne of greenhouse gas emitted between now and 2050 will count. Where emissions rise in one sector, we will have to achieve corresponding falls in another. More information on the 4th carbon budget can be found here: http://www.decc.gov.uk/en/content/cms/emissions/carbon_budgets/carbon_budgets.aspx