Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213

Prepared for RWE npower

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Overview

In this report, NERA Economic Consulting and Imperial College London review Ofgem's recent Impact Assessment relating to proposals to reform the Transmission Network Use of System (TNUoS) Charging Methodology. We find that Ofgem's "minded to" decision to implement a new TNUoS methodology, known as "WACM 2", is flawed for the following reasons:

- Despite Ofgem's claims to the contrary, our analysis suggests that the proposed charging model does not reflect the recent reforms to the transmission investment planning procedures set out in the National Electricity Transmission System (NETS) Security and Quality of Supply Standards (SQSS);
- Ofgem has failed to compare the costs generators impose on the transmission system to WACM 2 TNUoS charges. Hence, Ofgem cannot robustly conclude whether or not the proposed charging model is cost reflective;
- Our own comparison suggests that charges resulting from the WACM 2 methodology do not reflect incremental transmission costs any better than the status quo methodology;
- Ofgem has failed to rigorously account for the distributional effects created by the proposed charging model. Significant distributional effects will add to perceptions of regulatory risk and increase costs to consumers through higher financing costs;
- The WACM 2 charging model will distort dispatch and competition in the wholesale electricity market and distort cross-border trade in the European Union, because it links TNUoS charges to a plant's load factor; and
- Leaving aside these significant problems with the decision to implement the WACM 2 charging model, Ofgem's decision to implement the new arrangements from 1 April 2014 takes no account of the time it takes to respond to changes in TNUoS, which means any efficiency benefits in this first year would be at best negligible. A later implementation date (e.g. 1 April 2015) would reduce somewhat the distributional effects associated with the proposed reforms, and would not increase or decrease the impact of reform on efficiency.

It would therefore be inconsistent with Ofgem's statutory duties and the relevant objectives of the Use of System Charging Methodology for Ofgem to implement the WACM 2 charging methodology.

Background

In the context of Project TransmiT, NERA Economic Consulting and Imperial College London have been commissioned by RWE npower to review the recent Impact Assessment published by Ofgem relating to proposals to reform the Transmission Network Use of System (TNUoS) Charging Methodology.[1]

Historically, transmission network investment has been driven by the need to provide a secure network at times of peak load. The philosophy of the existing TNUoS charging methodology was clearly aligned with this historical network investment driver and the investment process that was specified in the original NETS SQSS "peak demand" condition.

However, over the coming decade, the need for transmission reinforcement will increasingly be driven by the need to accommodate the output from intermittent renewable generators connecting to the system, often in remote locations. This development means that there are now two "dual" drivers of transmission investment: ensuring peak security and making an economic trade-off between investment in additional transmission reinforcements and constraint costs during year round conditions. Accordingly, reforms to the NETS SQSS through GSR009 have taken place to reflect these dual drivers of transmission investment requirements in the investment planning process and the investment standards to which TOs are obliged to adhere under their licences.

As discussed further below, for TNUoS charges to be cost reflective, they must fully reflect the investment requirements and process specified in the new SQSS, so a key theme of Project TransmiT has been the perceived need to reflect changes to the SQSS in the TNUoS charging methodology. As part of this report, we therefore appraise whether Ofgem's "minded to" decision achieves the aim of making TNUoS charges reflect the investment costs that TOs incur to comply with the new SQSS planning standards.

The Basis for Ofgem's Decision

In its recent Impact Assessment, Ofgem considered the case for introducing a range of charging models put forward by the Connection and Use of System Code (CUSC) Modification Panel following the Project TransmiT Significant Code Review (SCR). Ofgem announced that it is "minded to" implement one of the variants, known as "Workgroup Alternative CUSC Modification 2" (WACM 2). Ofgem has proposed the earliest feasible implementation date of 1 April 2014 for the new charging model.

As part of its Impact Assessment, Ofgem considers a range of quantitative and qualitative evidence regarding the merits of the proposed charging models. To some extent Ofgem's minded-to decision is based on quantitative modelling analysis of the WACM 2 charging model, conducted by National Grid, suggesting the reform would reduce customer bills and increase social welfare.

However, Ofgem acknowledges some limitations of this modelling, and its decision is based primarily on its belief that the WACM 2 charging model is more cost reflective that the alternatives, including the status quo. Ofgem believes that the WACM 2 charging model is more cost reflective than the status quo, and so it will increase the efficiency of transmission

[1] Project TransmiT : Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, Ofgem (137/13), 1 August 2013.

network usage and enhance competition. The majority of evidence on which Ofgem relies to assess whether the alternative charging models are cost reflective was published in the Final Modification Report (FMR) paper, prepared by the Workgroup set up during the Project TransmiT SCR process.

Cost Reflectivity

For a generation TNUoS charging model to be cost reflective, as noted above, it must reflect the costs that TOs incur to accommodate an incremental MW of generation capacity. The investments required to accommodate incremental generation capacity onto the transmission system, and so the costs of accommodating generation capacity, are defined by the planning processes and standards set out in the SQSS.

Any one of three planning requirements in the SQSS might contribute to the costs of accommodating generation at a particular point of the network: the obligation to provide capacity to ensure "demand security", the obligation to provide capacity to meet the SQSS "economic criterion", and the obligation to conduct cost-benefit analysis (CBA) to identify if any further reinforcements are efficient. Although the WACM 2 charging model reflects the costs of complying with the "demand security" standards imposed by the SQSS, our review and analysis suggests that the WACM 2 charging model does not reflect the costs of adhering to the other two transmission network planning requirements:

- None of the analysis performed by the Workgroup or Ofgem has explicitly identified whether the binding drivers of transmission investment (and hence the costs that should be reflected in TNUoS charges) is the SQSS "economic criterion" or the investments prescribed by full CBA;
- Our illustrative examples show that the proposed charging model does not reflect the costs imposed on the TOs by the need to comply with the "economic criterion" in the SQSS. Hence, if adherence to the SQSS "economic criterion" is the binding driver of investment, then the WACM 2 charging model is not cost reflective;
- Neither the Workgroup nor Ofgem have performed any assessment of whether WACM 2 tariffs reflect transmission system costs prescribed by a CBA model better than those under the status quo or the alternative charging models Ofgem considered. Hence, if the obligation to perform additional transmission investments that are justified on the basis of a CBA is the binding driver of investment, then the analysis considered by Ofgem is inadequate to evaluate whether the WACM 2 model is cost reflective; and
- The analysis performed by the Workgroup and Ofgem that aims to assess whether the proposed charging models reflect the costs of investment to accommodate generation prescribed by a CBA model was flawed and incomplete. Our own comparison between incremental transmission costs (estimated using a CBA model) and WACM 2 suggests that the WACM 2 charging model is no more cost reflective than the status quo charges.

Our analysis therefore shows there is no objective basis for Ofgem's claim that the WACM 2 charging model would improve the cost reflectivity of transmission charging. Hence, it does not better achieve the objectives of the Use of System Charging Methodology, set out in Condition C5 of National Grid's Licence, that charges should "*reflect, as far as is reasonably practicable, the costs incurred by the transmission operator*" because the methodology does not reflect the costs of providing the investments prescribed by the SQSS.

The Impact on Competition

Ofgem considers that the WACM 2 charging model will enhance competition as it is more cost reflective than the status quo, whereas our analysis suggests this is not the case. In addition, through our review of Ofgem's Impact Assessment, we have found a number of respects in which the proposed WACM 2 charging model would be detrimental to competition:

- Ofgem has failed to perform distributional analysis that considers the impact of the proposed reform on individual industry players, and moreover, it has failed to devise any formal standard for weighing up the harm caused by the significant distributional effects of the reforms against any supposed efficiency savings;
- The WACM 2 charging model would link TNUoS charges to plants' historic load factors. This reform creates an additional variable cost that generators incur when they take dispatch decisions, and so may distort competition in the wholesale electricity market; and
- Changes to the current regime, without grand-fathered compensation mechanisms, undermine future incentives to invest efficiently in response to future charging signals, as investors will place less weight on the signals conveyed through TNUoS charges when taking investment decisions. Ofgem has failed to consider this effect on the efficiency of entry and exit decisions in its appraisal of options.

Review of Quantitative Modelling

There are a number of problems with the modelling presented in Ofgem's Impact Assessment that undermine the robustness of the results:

- As set out in NERA's 2012 report, we see a number of structural problems associated with the modelling approach developed by Redpoint and implemented by National Grid for the analysis of the alternative charging models;[2]
- National Grid's modelling artificially inflates the costs of the status quo case (and thus the benefits of the alternatives) by assuming a higher level of renewables penetration than in other cases;
- National Grid's finding that the alternative charging models reduce power prices, and thus benefit consumers, is illogical. It is inconsistent with both economic theory and the electricity trading arrangements in Britain (in particular the proposed Capacity Payment Mechanism); and
- The results of the modelling appear sensitive to assumptions made about the future evolution of the power system, which depends, amongst other things, on commodity prices, government policy and demand growth. In light of the uncertainties over these factors in the coming decades, it would therefore have been prudent to perform sensitivity

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2 The following report provides a more detailed discussion of the shortcomings of the Redpoint modelling: Project TransmiT: Ofgem's Assessment of Options for Change: A Review Prepared for RWE npower, NERA Economic Consulting, 14 February 2012, Appendix A.

analysis before reaching conclusions that reform to the TNUoS methodology is justified. Ofgem failed to perform such sensitivity analysis.

Implementation Date

Ofgem justifies the choice of an early implementation on the basis that it would "*avoid further delay and move quickly in what we consider to be the right direction*".[3] Rushing the change through in 2014 will not produce any benefit because generators cannot reduce their TEC over this timescale without incurring penalties, and 2014/15 is too soon to affect new generators' locational decisions. The earliest implementation date that might potentially produce benefits is April 2015, as generators would be able to adjust their behaviour in response, and a delay will also reduce the material distributional effects that would arise from the reform.

Interactions with Other Aspects of Market Design

Ofgem has not considered the possibility that further reform of the TNUoS charging regime may be necessary to reflect the EU Target Model, which may, as the Authority has acknowledged, result in market splitting that would effectively price constraints through regional variation in the wholesale electricity price. Such a reform would materially alter the case for the WACM 2 charging model, which seeks to reflect these costs through TNUoS.

The use of load factor, and the increase (or decrease) in generators' variable costs of dispatch, may also distort trade with neighbouring markets, as generators in these markets do not face similar charges.

Conclusions

Ofgem's case for implementing the WACM 2 TNUoS charging model hinges on the argument that it is more cost reflective than the status quo and the alternatives under consideration. We have identified several flaws in the evidence Ofgem uses to reach this conclusion, including significant shortcomings in the quantitative modelling it cites. Moreover, our own comparison of WACM 2 charges to incremental transmission costs suggests that charges resulting from the WACM 2 methodology are no more cost reflective than the status quo methodology.

At the same time, Ofgem's decision ignores numerous problems associated with Ofgem's minded to decision to introduce the WACM 2 charging model. In particular, Ofgem has failed to rigorously account for the costs of distributional effects, it has overlooked the distortions to dispatch the WACM 2 model will cause, and does not account for the possibility that further market reform to implement the EU Target Model will necessitate further changes to the TNUoS methodology in the coming years.

Finally, and leaving aside these significant problems with the decision to implement the WACM 2 charging model, Ofgem's decision to implement the new arrangements from 1

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[3] Ofgem para 6.101

April 2014 takes no account of the time it takes to respond to changes in TNUoS, and would exacerbate the distributional effects associated with the proposed reforms.

1. Introduction

NERA Economic Consulting and Imperial College London have been commissioned by RWE npower to review the recent Impact Assessment published by Ofgem relating to the proposals to reform the British Transmission Network Use of System (TNUoS) Charging Methodology.[4]

1.1. Background on Project TransmiT

In 2010, Ofgem announced a fundamental review of current electricity charging arrangements, called "Project TransmiT". Through this process, Ofgem originally proposed three possible scenarios for charging going forward:

- The "status quo", whereby the current model would continue with minor modifications;
- A "socialised" charging model, whereby generation TNUoS charges would be paid through a uniform charge per MWh of energy output; and
- An "improved ICRP" charging model, which seeks to alter the existing charging model to, amongst other things, better reflect how different types of generator impose different costs on the transmission system.

Ofgem considered the introduction of the "improved ICRP" and "socialised" charging models in the "options for change" document it published during the Project TransmiT process. In this paper, Ofgem ruled out the socialised charging model on the grounds that removing the economic signals conveyed to users through locational transmission charges would cause a "disproportionate" increase in power sector costs and customer bills. At the same time, it suggested that "*improved ICRP is the right direction for transmission charging arrangements*".[5] However, following this consultation, it published a decision that suggested that the "*the choice between Improved ICRP and the Status Quo is not clear cut*".[6]

It therefore initiated a Significant Code Review (SCR). Ofgem directed National Grid to organise an industry Workgroup to draft a modification to the Connection and Use of System Code (CUSC), referred to as modification CMP213, to develop the "improved ICRP" methodology.[7] The Workgroup considered a range of variants on the original "improved ICRP" methodology. At a meeting of the CUSC Modifications Panel on 31 May 2013, the Panel voted by majority that 8 out of the 27 options better facilitate the "Applicable CUSC Objectives". The result of this majority vote formed the Panel's recommendation to Ofgem.

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4 Project TransmiT : Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, Ofgem (137/13), 1 August 2013.Unless otherwise specified, all other citations of Ofgem in this report refer to this document.

5 Project TransmiT: Electricity transmission charging: assessment of options for change, Ofgem (188/11), 20 December 2011, para 6.16.

6 Electricity transmission charging arrangements: Significant Code Review conclusions, Ofgem (65/12), 4 May 2012, page 5.

7 Stage 02: Workgroup Consultation, Connection and Use of System Code (CUSC), CMP213 Project TransmiT TNUoS Developments, National Grid, 7 December 2012, para 1.7-1.10.

On 14 June 2013 the CUSC Panel submitted its Final Modification Report (FMR) to Ofgem for its consideration.[8]

On 1st August 2013, Ofgem announced that it is minded to implement one of the variants of "improved ICRP," in favour of which the CUSC Modification Panel had voted, known as "Workgroup Alternative CUSC Modification 2" (WACM 2).[9] WACM 2 is similar to the original "improved ICRP" model, but assumes that plants in regions with high concentrations of low-carbon generation impose higher costs on the transmission network than those in regions with a diverse mix of generation sources (or those dominated by thermal generation).

A stakeholder consultation on the latest proposals is currently underway, following which Ofgem plans to publish a final decision towards the end of this year.

1.2. Ofgem's "Minded to" Decision

1.2.1. Comparison against relevant decision-making criteria

Ofgem's Impact Assessment compares the various charging options submitted by the Industry Workgroup against the following 'relevant objectives' for changes to the Use of System charging methodology, as set out in Section C5 of National Grid's transmission licence:

- **The methodology facilitates competition in the generation and supply of electricity**

  Ofgem's initial view is that "*all of the CPM213 proposals are more cost reflective than the status quo*" and would therefore *"promote competition more effectively*".[10]

- **The methodology yields charges which reflect, as far as is reasonably practicable, the costs incurred by the transmission operator**

  In Ofgem's view, alternatives featuring the proposed methodology Diversity 1 "*most appropriately reflect the TOs' investment decisions for "year round" conditions, and therefore are the most cost reflective options*".[11]

- **The methodology, as far as is reasonably practicable, properly takes account of the developments in the transmission licensees' transmission business**

  Ofgem believes that, of the options considered, the WACM 2 charging model "*best incorporates the developments of HVDC and island links as well as best taking into account the changing generation mix*".[12]

Ofgem has also compared the charging options against the Authority's principal objective to protect the interests of existing and future consumers, wherever appropriate through the promotion of effective competition. These interests include:

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[8] Ofgem, para 2.12.

[9] Ofgem, page 5

[10] Ofgem para 6.9

[11] Ofgem para 6.47

[12] Ofgem para 6.62

- **Reduction of greenhouse gas emissions**: Ofgem believes that "*All CMP213 proposals should further promote sustainable development relative to the Status Quo*" and that the modelling "*suggests that Diversity 1 options present the lowest risk to targets associated with reducing greenhouse gas emissions*".[13]
- **Security of supply**: Ofgem does not "*consider security of supply to be materially affected by any of the CMP213 options*".[14]
- **Consumer bill impacts:** Ofgem believes that the long term benefits of the new methodology "*are likely to outweigh considerably the short term disbenefits as regards consumer bills*".[15]

Ofgem's "minded-to position," based on its assessment against the above criteria is "**to implement WACM 2 in April 2014**".[16] As the above summary shows, Ofgem believes that WACM 2 will best facilitate all the "relevant objectives" for the Use of System charging methodology, as well as the Authority's principal objective.

1.2.2. Overview of the evidence on which Ofgem relies

As we describe in the subsequent sections of this report, Ofgem's minded-to decision to implement the WACM 2 charging model relies heavily on the assumption that WACM 2 will result in more cost-reflective charges. Ofgem believes that "*the new, more cost reflective charges*" will result in lower systems costs and expects any cost savings to be "*passed through to consumers through the operation of competitive markets in generation and supply*". [17] Ofgem argues that increased cost-reflectivity will reduce discrimination, enhance competition, and promote more efficient use of the transmission network. Ofgem also draws on evidence from National Grid's modelling of the alternatives, particularly when evaluating likely customer bill affects. This modelling suggests the WACM 2 charging model will reduce power sector costs and cut consumer bills by lowering wholesale power prices materially.

However, as we discuss in the remainder of this report, the evidence that underlies Ofgem's minded-to decision is not sound. As described in Chapters 2 and 3, our review of the qualitative evidence considered by Ofgem on whether the WACM 2 model is more cost reflective than the alternatives and the status quo shows that this evidence is flawed and incomplete. In particular, Ofgem's failure to compare WACM 2 charges to any estimate of the incremental cost of reinforcement triggered by generators means the conclusion that WACM 2 is more cost reflective is not justified. Our own independent comparison of WACM 2 tariffs to incremental reinforcement costs suggests that the proposed reform will not materially improve the extent to which generation TNUoS charges reflect costs.

13 Ofgem para 6.69.

14 Ofgem para 6.76

15 Ofgem para 6.81

16 Ofgem para 6.103

17 Ofgem para 6.78

Additionally, in Chapter 4, we detail a range of flaws in the National Grid modelling that undermine the conclusion that power sector costs and customer bills will fall as a result of introducing the WACM 2 methodology. These flaws, some of which Ofgem and its consultants have recognised, mean this modelling work does not provide a reliable basis for decision-making. In particular, the lack of sensitivity analysis, especially given the very marginal improvements in welfare the modelling suggests would arise from implementing the WACM 2 charging model, undermines the robustness of Ofgem's conclusions.

Finally, Ofgem proposes to implement the WACM 2 charging model as soon as possible, in April 2014, on the basis that this would "*avoid further delay and move quickly in what we consider to be the right direction*".[18] As described in Chapter 5, the inability (or lack of incentive) of generators to alter their TEC over this timeframe means the decision to implement the reform in April 2014, rather than April 2015 for example, would achieve no efficiency benefit and exacerbate the significant distributional effects caused by changes to TNUoS.

1.3. Report Overview

The remainder of this report is structured as follows:

- Chapter 2 appraises the cost reflectivity of the proposed charging model, as well as the evidence on which Ofgem relied to conduct its own appraisal of whether the proposed charging model is cost reflective;
- Chapter 3 considers the impact of the proposed modifications to TNUoS charges on competition;
- Chapter 4 evaluates the quantitative evidence on which Ofgem's minded-to is based, in particular the modelling performed by National Grid;
- Chapter 5 evaluates Ofgem's proposal to implement the WACM 2 charging model as soon as possible on 1 April 2014, rather than at some later date;
- Chapter 6 considers the consistency of the minded-to decision to implement the WACM 2 model with other aspects of market design, such as the EU Target Model and Ofgem's Integrated Transmission Planning and Regulation (ITPR) project; and
- Chapter 7 concludes.

[18] Ofgem para 6.101

2. Cost Reflectivity

2.1. Aligning TNUoS Charges with the NETS SQSS

Historically, transmission network investment has been driven by the need to provide a secure network at times of peak load. The philosophy of the existing TNUoS charging methodology was clearly aligned with this historical network investment driver and the investment process that was specified in the original NETS SQSS "peak demand" condition.

However, over the coming decade, the need for transmission reinforcement will increasingly be driven by the need to accommodate the output from intermittent renewable generators connecting to the system, often in remote locations. This development means that there are now two "dual" drivers of transmission investment: ensuring peak security and making an economic trade-off between investment in additional transmission reinforcements and constraint costs during year round conditions. Accordingly, reforms to the NETS SQSS through GSR009 have taken place to reflect these dual drivers of transmission investment requirements in the investment planning process and the investment standards to which TOs are obliged to adhere under their licences.

As discussed further below, for TNUoS charges to be cost reflective, they must fully reflect the investment requirements and process specified in the new SQSS, so a key theme of Project TransmiT has been the perceived need to reflect changes to the SQSS in the TNUoS charging methodology. As Ofgem notes:

> "*The current charging methodology only recognises peak security as a driver of transmission investment and charges all plant within a zone the same tariff. However, as set out in the NETS SQSS, a second assessment criterion is also now used to determine an optimal trade off between constraint costs and transmission capacity. The current TNUoS charging regime does not reflect these two drivers of network investment and how different types of plant contribute toward these.*"[19]

In this chapter, we therefore appraise whether Ofgem's "minded to" decision achieves the aim of making TNUoS charges reflect the investment costs that TOs incur to comply with the new SQSS planning standards when they invest to accommodate incremental generation capacity.

2.2. Reforms to the NETS SQSS Under GSR009

Section 4 of the NETS SQSS on the "Design of the Main Interconnected Transmission System" describes criteria that the TOs must adhere to when planning the development of the transmission system. In particular, it determines the amount of transmission boundary capacity that TOs are required by their licences to provide, given the profile of installed capacity on the system. Until recently, the investment criteria in the SQSS required TOs to provide sufficient transmission capacity to operate the system in Average Cold Spell (ACS)

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[19] Ofgem para.6.35

peak demand conditions, where the output from all capacity on the system is scaled uniformly to meet demand.

In November 2011,[20] Ofgem approved SQSS modification proposal GSR009, which followed from a consultation on the appropriate transmission planning standards in a system dominated by significant volumes of intermittent generation.[21] Following GSR009, the SQSS now obliges TOs to provide sufficient boundary capacity to fulfil two criteria:[22]

1. a "demand security criterion" that requires sufficient boundary capacity to ensure continued system operation in ACS peak demand conditions, on the assumption that intermittent generation and interconnectors are unavailable, and with all other generation "variably scaled" uniformly to match generation to demand; and
2. an "economic criterion" that requires sufficient boundary capacity to ensure continued system operation in ACS peak demand conditions, on the assumption that output from intermittent, nuclear, Carbon Capture and Storage (CCS), pumped storage and interconnectors are scaled by specific factors, and the remainder of generation is variably scaled to meet demand.

The scaling factors underlying the generation backgrounds used by these two criteria, which are now written into the SQSS, are shown below in Table 2.1.

Table 2.1
Scaling Factors Specified in SQSS Planning Criteria

Technology	Demand Security Criterion	Economic Criterion
Peaking plant (e.g. OCGTs)	Variably Scaled	0%
Wind, wave and tidal	0%	70%
Nuclear and CCS	Variably Scaled	85%
Pumped storage	Variably Scaled	50%
Interconnectors	0%	100%
Other	Variably Scaled	Variably Scaled

Source: SQSS Version 2.3, National Grid, 4 April 2012, Appendices C and E.

Both the "demand security" and "economic" criteria set *minimum* levels of investment that the TOs must provide on transmission boundaries of the Main Interconnected Transmission System. In addition, the SQSS requires that TOs provide additional transmission capacity

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20 Decision on proposal to amend the minimum transmission capacity requirements in the System Security and Quality of Supply Standard (SQSS) - GSR009, Ofgem, 1 November 2011.

21 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, SQSS Review Group Consultation GSR009, 11 June 2010.

22 National Electricity Transmission System Security and Quality of Supply Standard Amendment Report GSR009, Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, Prepared by the SQSS Review Group for submission to the Authority by NGET, SHETL and SPT, 1 April 2011.

where it is "economically justified".[23] One interpretation of this requirement is that TOs must also conduct a full cost benefit analysis to assess whether additional transmission investments are economically justified in comparison to alternative operational measures, i.e. to optimise the trade-off between constraint and investment costs. The Authority, in its decision letter regarding GSR009, noted that *"we recognise that, in practice, investment decisions are based on more than simply applying the SQSS rules to one isolated boundary for a particular set of background conditions. In particular:*

- *Large investments are subject to more detailed cost benefit analysis taking into account system-wide requirements such as interactive boundaries, multiple-year conditions with potential variation in capacity requirement, and the cost of specific elements based on a particular set of circumstances and level of uncertainty.*
- *There will also be wider consideration of other factors such as impact on overall security of supply, and facilitation for future development of various types of generation.*

Therefore any actual investment decision could differ from that implied by applying either the rules proposed by GSR009, or the current rules". [24]

2.3. Reflecting Changes to the SQSS in TNUoS Charges

2.3.1. The WACM 2 model does not reflect the costs that TOs incur to comply with the SQSS

Although the WACM 2 charging model reflects the costs of complying with the "demand security" standards imposed by the SQSS, our review and analysis suggests that the WACM 2 charging model does not reflect the costs of adhering to the other two transmission network planning requirements:

- None of the analysis performed by the Workgroup or Ofgem has explicitly identified whether the binding drivers of transmission investment (and hence the costs that should be reflected in TNUoS charges) is the SQSS "economic criterion" or the investments prescribed by full CBA;
- Our illustrative examples show that the proposed charging model does not reflect the costs imposed on the TOs by the need to comply with the "economic criterion" in the SQSS. Hence, if adherence to the SQSS "economic criterion" is the binding driver of investment, then the WACM 2 charging model is not cost reflective;
- Neither the Workgroup nor Ofgem have performed any assessment of whether WACM 2 tariffs reflect transmission system costs prescribed by a CBA model better than those under the status quo or the alternative charging models Ofgem considered. Hence, if the obligation to perform additional transmission investments that are justified on the basis of a CBA is the binding driver of investment, then the analysis considered by Ofgem is inadequate to evaluate whether the WACM 2 model is cost reflective; and

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[23] NETS SQSS, Version 2.3, paragraph 4.10.

[24] Decision Letter GSR009, Gas and Electricity Markets Authority, 1 November 2011.

- The analysis performed by the Workgroup and Ofgem that aims to assess whether the proposed charging models reflect the costs of investment to accommodate generation prescribed by a CBA model was flawed and incomplete. Our own comparison between incremental transmission costs (estimated using a CBA model) and WACM 2 suggests that the WACM 2 charging model is no more cost reflective than the status quo charges.

Our analysis therefore shows there is no objective basis for Ofgem's claim that the WACM 2 charging model would improve the cost reflectivity of transmission charging, so does not achieve the objective, set out in Ofgem's direction to NGET, to develop a methodology that *"better reflects the transmission investment framework set out in the NETS SQSS"*.[25] Also, it does not better achieve the objectives of the Use of System Charging Methodology, set out in Condition C5 of National Grid's Licence, that charges should "*reflect, as far as is reasonably practicable, the costs incurred by the transmission operator*".

2.3.2. The proposed "year round" charges are not consistent with the economic criterion in the SQSS

In addition to the transmission capacity required to provide peak security, the economic criterion in the SQSS specifies that the minimum additional capacity that TOs are required by their licences to provide, as described in Section 2.2. The transmission capacity requirements imposed by the economic criterion in the SQSS depend on a generation background that scales generators' output by fixed percentages (see Table 2.1), not by diversity factors or by annual load factor.

We provided worked examples illustrating the operation of the economic criterion in our earlier report assessing Ofgem's Project TransmiT "Options for Change" paper in February 2012.[26] These examples compare the costs imposed to comply with the SQSS economic and peak security criteria, with the "improved ICRP" charges (i.e. National Grid's original proposal). The charging models that Ofgem's Impact Assessment considers are slightly different, in that they all contain diversity factors that attempt to reflect sharing of transmission assets. However, they still result in charges that differ from the costs TOs would incur to accommodate generation while complying with the SQSS dual planning criteria (peak security and economic).

In Appendix A, we have updated the worked examples from our previous paper to illustrate the differences between the costs the TOs are obliged to incur to comply with the SQSS economic and peak security criteria and the charges computed using the WACM 2 methodology. These differences are significant and demonstrate that the charges emerging from the model proposed by Ofgem are not reflective of the costs incurred by TOs due to these SQSS planning standards.

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[25] Ofgem para 2.10

[26] Project TransmiT: Ofgem's Assessment of Options for Change: A Review Prepared for RWE npower, NERA Economic Consulting, 14 February 2012. Viewable at: http://www.nera.com/nera-files/PUB_Project_TransmiT_0212.pdf c

2.3.3. The evidence supporting the hypothesis that the WACM 2 charging model reflects incremental costs from a CBA model is flawed

As discussed in Section 2.2 above, transmission investments can be triggered under the SQSS either to comply with the economic and peak security criteria, or because transmission investments (in addition to that required by these two criteria) can be justified on the basis of a full CBA approach to transmission planning. The Ofgem Impact Assessment and the FMR document therefore consider the question of whether the WACM 2 charging model, and the alternatives described in Appendix A of this report, reflect the characteristics of generators that determine the level of transmission investment that a CBA modelling exercise would prescribe. However, for a number of reasons, this analysis is flawed, as we describe below.

2.3.3.1. The supposed linear relationship between incremental constraint costs and load factor may be "mis-specified"

Several of the alternative charging models that Ofgem considers (see Appendix A) scale generators' liability to pay year round charges to load factor. The use of load factor to scale "year round" charges is based on the assumption that a simple one-for-one linear relationship exists between ALF and incremental constraint costs. Ofgem considers this assumption to be appropriate, based on the analysis presented in the FMR, and thinks that "*it is an improvement in terms of cost reflectivity compared to the existing methodology which does not acknowledge this relationship at all"*.[27]

However, the evidence to support the use of load factor to scale the year-round charge[28] is flawed for a range of reasons, so does not prove that the link between load factor and constraint costs is linear:

- The scatter plots in Annex 9 of the FMR document, on which Ofgem appears to rely in its Impact Assessment,[29] compare incremental constraint costs to load factor, with incremental constraint costs estimated by adding a MW of generation. This analysis purports to be based on "*a transmission network that is as far as possible sized optimally*".[30] Although the drafting of the Annex does not describe the methods used precisely, it appears that the modelling did not allow for additional transmission capacity to be constructed once each incremental MW of generation capacity was added.
  - If the incremental constraint cost triggered by an incremental MW of generation exceeds the cost of adding transmission capacity, then it would be efficient to add transmission capacity in response to increases in generation capacity. If the model does not have the option to add capacity, it may exaggerate the constraint costs imposed on the system by additional generation capacity. Moreover, allowing the

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[27] Ofgem para 6.38

[28] For example, see the analysis as presented to the Workgroup in Annex 9 of the FMR document, and referred to extensively in Annex 4 of the FMR.

[29] Ofgem para 6.49

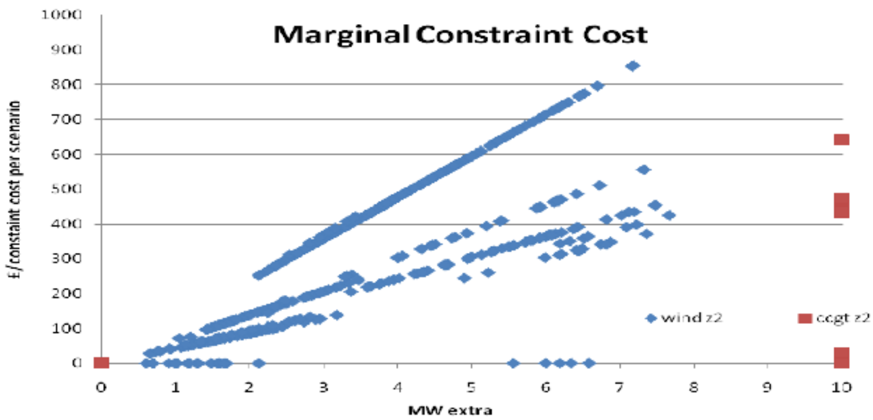
[30] FMR, para 9.6.

model the option to expand transmission capacity may cause the supposed linear relationship between incremental costs and load factor to break down.

- If the intention of the analysis in the FMR document is to reflect incremental constraint costs, and not investment costs, in TNUoS charges, then the resulting methodology would appear at odds with condition C26, paragraph 6 of the Transmission Licence Standard Conditions, which expressly requires that constraint costs be recovered through a uniform £/MWh charge without regional variation.
- The scatter plots in Annex 9 of the FMR document are also based on an extremely small number of data points for just one snapshot. Hence, they do not provide robust evidence that the relationship between incremental constraint costs and load factor is linear in any systematic way that would justify a load factor adjustment in charges.

- Figure 3 in Annex 4 of the FMR document (reproduced below as Figure 2.1) compares the output of a plant in a positive TNUoS zone with incremental constraint costs. It shows that, although some positive correlation exists, the data points on the chart are spread across a number of different "lines". Far from suggesting the relationship is linear, this chart suggests that the link between generator output and constraint costs is determined by much more complex relationships.

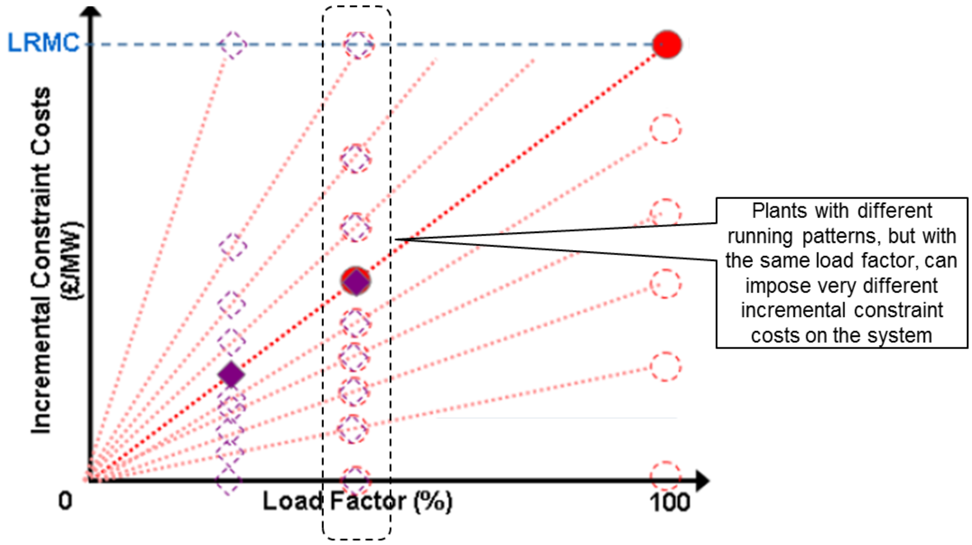
Figure 2.1
Marginal Constraint Cost vs. Plant Output in Positive TNUoS Zone



Source: FMR Document, Figure 3

- Figure 16 in Annex 4 of the FMR document also undermines the argument that the relationship between constraint costs and load factor is linear. The figure, reproduced below as Figure 2.2, seems to contain varying slopes of the dotted lines to illustrate "*the effect of changes in the correlation between generation plant running…* [with] *times of transmission constraints*". The figure is illustrative, so does not represent any kind of modelling result. Nonetheless, the FMR document uses it to show that the incremental constraint cost imposed by a particular plant has a linear relationship with load factor, but that this linear relationship shifts depending on the coincidence of plant running with periods of constraints. However, as noted by the annotation we added to the figure below, different generators with the same load factor can impose very different costs on the system, depending on their exact running patterns. The figure also shows that the relationship between load factor and constraint costs is far from linear across a range of plants.

Figure 2.2
Impact of Running Times on Incremental Constraint Costs vs Load Factor Relationship



Source: FMR Document, Figure 16

Moreover, a report by Bath University that examined the link between constraint costs and load factor, which the FMR includes as Annex 13, concludes that:[31]

> "*the load factor of a single generation technology is not uniform across the system but will be shaped by different generator and demand parameters, and features of the transmission system… All these features will combine to impact congestion costs and generator load factor in different ways…The relationship most certainly can not be assumed to be linear… Employing load factor as a surrogate for the cause of this congestion would smear the consequence for what is a highly localised problem across all boundaries and throughout the year. It cannot provide the necessary economic message for reducing congestion, and it certainly would not reflect the costs of congestion as required by SLC 5.5(b)*".

2.3.3.2. Neither the FMR nor Ofgem's Impact Assessment link the "diversity" adjustments to the flaws with the original model they aim to address

The FMR document omits any evidence to show how the three diversity adjustments, when applied to the year round charge, reflect the fundamental drivers of constraint costs in the charges faced by generators:

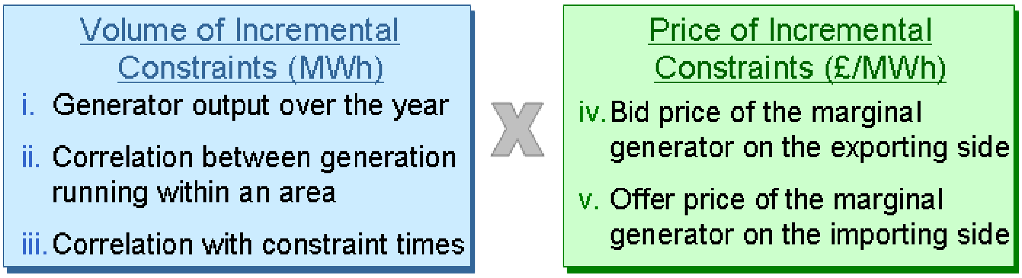
- Figure 6 of Appendix 4 in the FMR document, reproduced below as Figure 2.3, describes a range of factors that the Workgroup identified as relevant drivers of incremental constraint costs. The following sections of the FMR document (paragraphs 4.67-4.100) then provide some qualitative discussion of why each of the factors shown on the chart is a relevant determinant of incremental constraint costs, concluding with statements that

[31] Professor Furong Li, Jiangtao Li and Professor David Tolley, Year-round System Congestion Costs - Key Drivers and Key Driving Conditions: A report to Centrica and RWE, January 2013, Section 2.6.

each factor is accounted for in the modelling presented to the Workgroup. For instance, paragraph 4.98 states, with reference to the factors in the green box on the right hand side of Figure 2.3, that "*The Proposer noted that the effect of bid and offer prices on incremental constraint costs is reflected in the market modelling undertaken and shared with the Workgroup*".[32]

- Although the FMR document discusses each driver of constraint costs, the document does not present the results of any modelling that shows the proposed new charging models reflect these factors. Hence, the FMR document does not demonstrate whether the proposed charging models reflect the factors identified in the figure.

Figure 2.3
Drivers of Incremental Constraint Costs Identified by the Workgroup



Source: FCR document, page 29.

- Paragraphs 4.101 to 4.121 then report the results of analysis conducted by the Workgroup to evaluate the relative impacts of these factors on constraint costs. However, all results presented in the paper are illustrative, so the actual analysis underlying the statements in this section of the FMR document cannot be independently appraised.
- A description of each "diversity" adjustment and a mechanistic description of how it is implemented follow in the next paragraphs of the FMR, but these do not address how the specific calculations included in the diversity adjustments rectify the flaws identified with the original NGET proposal.[33] Nor does the document contain any analysis that the year round charges resulting from the three diversity methods accurately proxy for the true incremental infrastructure costs incurred by TOs to accommodate additional generation capacity.

Ofgem's Impact Assessment also fails to explain the link between the diversity adjustments and the fundamental drivers of constraint costs. Ofgem states that alternatives featuring Diversity 1 "*recognise that intermittent plant in low carbon dominated zones tend to drive more transmission investment*" and concludes that these alternatives are "*more cost reflective than the NGET Original which does not reflect this*".[34] However, the Impact Assessment

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[32] FMR document, para. 4.98.

[33] For example, the description of Diversity 1, which is part of the WACM 2 model Ofgem is "minded-to" adopt, is presented in paragraphs 4.135-4.140 of the Annexes to the FMR report. While this section contains a mechanistic description of how the model is implemented, it contains no argumentation that the approach reflects the costs of accommodating an incremental MW of transmission investment capacity

[34] Ofgem para 6.41

does not present any evidence to support this conclusion, and instead makes reference to the analysis presented in the FMR. For example:

> ”*We do not think this is a reasonable approximation of the way that transmission investments are considered and we do not think it is consistent with the relationships between incremental costs and load factors* ***presented to us in the FMR***.“[35]

Thus it seems that Ofgem is, at least in part, relying on evidence from the FMR, that for the reasons described above is incomplete and flawed, to justify its conclusion that ”*alternatives that feature Diversity 1 most appropriately reflect the TOs' investment decisions for year round conditions, and are therefore the most cost reflective options*”.[36]

2.3.4. The “economic criterion” probably prescribes more investment than a full CBA, so may be the binding driver of transmission investments

In developing the reforms proposed under GSR009, the SQSS Review Group conducted analysis to compare the quantity of boundary reinforcement that a number of alternative security standards, like those listed in Table 2.1, would prescribe, as against the optimal quantity of boundary capacity that a full CBA suggests is required. According to the Review Group's analysis, the approach adopted in GSR009 prescribes the boundary reinforcements that were closest to those prescribed by a full CBA.[37] Hence, the selected methodology is sometimes referred to as a “pseudo CBA” approach, as it intends to mimic the outcomes of a full CBA, i.e. identify capacity provision that reflects an optimal trade-off between investment costs and congestion costs, taking account of the running patterns and load factors of different generation types.

In practice, the pseudo-CBA approach may prescribe levels of reinforcement investment above or below the level prescribed by a full CBA. However, evidence considered by the SQSS Review Group in 2011 suggests that the deterministic rule specified in Table 2.1, referred to as “Option 1e” tends to prescribe levels of investment close to, and slightly above, the theoretic optimum emerging from a full CBA.

The SQSS Review Group paper states that “*it is economically preferable to over-build than to under-build transmission due to the relative costs of constraints and transmission. The benefit comes from reducing the potential range of total costs, although the potential minimum total cost of transmission and constraints does increase with greater network development. In the group's view, the best of the deterministic options will: be based on the most probable future scenario, be within the CBA uncertainty region, build a level of transmission that reduces the total cost risk without incurring excess investment. The group considers that the option that most closely aligns with the central case CBA, which is based*

35 Ofgem para 6.46

36 Ofgem para 6.47

37 Amendment Report GSR009 Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, Prepared by the SQSS Review Group for submission to the Authority, 1 April 2011, Appendix 4.

on best view forecasts and tends to build transmission slightly above the mid-point of the uncertainty region, will meet the criteria. Approach 1e best achieves this".[38]

Therefore, transmission planning based on this "economic criterion" in the SQSS would tend to prescribe more transmission investment than would be prescribed by a full CBA. Because providing the capacity required under the "economic criterion" is a *minimum* requirement placed on TOs, it is unlikely that the investments prescribed by a full CBA would exceed those required by the pseudo-CBA approach in the SQSS. On that basis, the binding driver of transmission investment requirements is probably the need to comply with the "economic criterion" in the SQSS, and not the need to comply with the obligation to provide additional transmission capacity that is justified on the basis of a full CBA.

However, we have not seen any analysis performed by the Workgroup or Ofgem to assess whether the "economic criterion" or the need for a full CBA is the "binding" driver of transmission investment requirements. This omission is important because, to assess whether the alternative TNUoS charging models reflect the costs of accommodating additional generation capacity, a crucial first step is identifying the basis on which transmission investment decisions are really taken. If the economic and peak security criteria in the SQSS are usually the "binding" drivers of investment, then Ofgem's assessment of cost reflectivity should focus on whether WACM 2 charges reflect the economic criterion in the SQSS, and not whether WACM 2 charges reflect the marginal reinforcement costs emerging from a full CBA.

2.3.5. Ofgem has not appraised whether the WACM 2 charges are cost reflective

A fundamental failing of the Ofgem Impact Assessment and the FMR is their lack of any comparison between WACM 2 charges and the incremental costs of reinforcement that they aim to reflect. Without such a comparison, it is impossible for Ofgem to know which of the proposed alternative charging models most accurately reflect the incremental costs of accommodating generators on the system, and whether any of them are more cost reflective than the status quo.

The FMR document does compare incremental constraint costs to load factor, but this approach is an imprecise and inappropriate way of assessing whether the proposed year-round charges accurately reflect the incremental cost imposed on the system for the following reasons:

- The measure of load factor used in the diagram does not account for the five-year trailing average built into the WACM 2 model that Ofgem is "minded-to" adopt. Using five-year trailing averages might weaken the link that the FMR document suggests exists between the incremental constraint costs that generators impose on the system and their load factor, particularly in conditions where the generation mix is changing, and the load factors of

[38] Source: Review of Required Boundary Transfer Capability with Significant Volumes of Intermittent Generation, Consultation Reference: GSR009, Version: 1.0, Issued: 11th June 2010, Prepared By: SQSS Review Group, page 36.

thermal plants are likely to get "squeezed" as new low carbon plants come onto the system, as is now beginning to happen.

- The scaling factors used in the proposed charging models scale the year-round charge by load factor and/or a range of diversity factors (see Appendix A). Hence, it is not sufficient to demonstrate that load factor is correlated with incremental constraint costs, even if that had been done, which it has not. It would be more relevant to compare the modelled year-round charges to incremental constraint costs.

2.3.6. Our analysis suggests that WACM 2 charges are no more cost reflective than the status quo

In light of Ofgem's failure to compare WACM 2 tariffs to the incremental costs that generators impose on the system, we have performed our own analysis using Imperial College's Dynamic Transmission Investment Model (DTIM). Using the network representation in DTIM, which is designed to approximately reflect conditions on the British transmission system,[39] we computed the Long Run Marginal Cost (LRMC) of transmission that an incremental MW of generation triggers in each of DTIM's network zones. We then compared these estimates of LRMC to the WACM 2 and status quo TNUoS charges that generators would face under this network configuration. For this analysis, we use generation and demand backgrounds from National Grid's "gone green" scenario using data from 2013 to 2030.

A key finding of our analysis is that under both the status quo and WACM 2 methodologies, the charges we obtain are extremely sensitive to the level of HVDC cable utilisation assumed in the transport model, i.e. through the computation of desired flow and equivalent impendence. This assumed flow can vary between 10% and 80% of line capacity depending on the methodology used, resulting in significant variation in Scottish TNUoS charges. Although there is no objective basis on which to select a level of impendence on these bootstraps, our results shown below consider two sets of charges that assume 25% and 75% impendence to illustrate the sensitivity of charges to this choice.

The results of this analysis are presented Figure 2.4 and Figure 2.5 below, which show the LRMC of accommodating generation on the transmission system alongside status quo and WACM 2 TNUoS charges under the assumption of both 25% and 75% impendences.

2.3.6.1. WACM 2 charges do not better reflect the LRMC that low carbon generators impose on the transmission system than the status quo

The left hand side of Figure 2.4 shows that WACM 2 charges for wind generation are lower than cost reflective LRMC charges across all zones in 2013, while status quo TNUoS charges are higher.[40] However, this finding changes materially in 2020 and 2030. In the Scottish zones, WACM 2 and status quo charges for wind generators are both materially lower than LRMC under both impendence scenarios. Status quo charges in 2020 and 2030 in Scottish

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[39] The DTIM network representation is illustrated in: Project TransmiT: Impact of Uniform Generation TNUoS, Prepared for RWE npower, NERA Economic Consulting and Imperial College London, 31 March 2011, Figure 2.4.

[40] There is no sensitivity to the assumed level of impendences in this year, as the bootstraps are not yet in operation.

zones are higher than WACM 2, and thus closer to LRMC. In England and Wales, WACM 2 charges in 2020 are slightly above LRMC, and status quo charges are slightly below LRMC by about the same amount. In 2030, status quo charges are close to LRMC, but WACM 2 charges are higher.

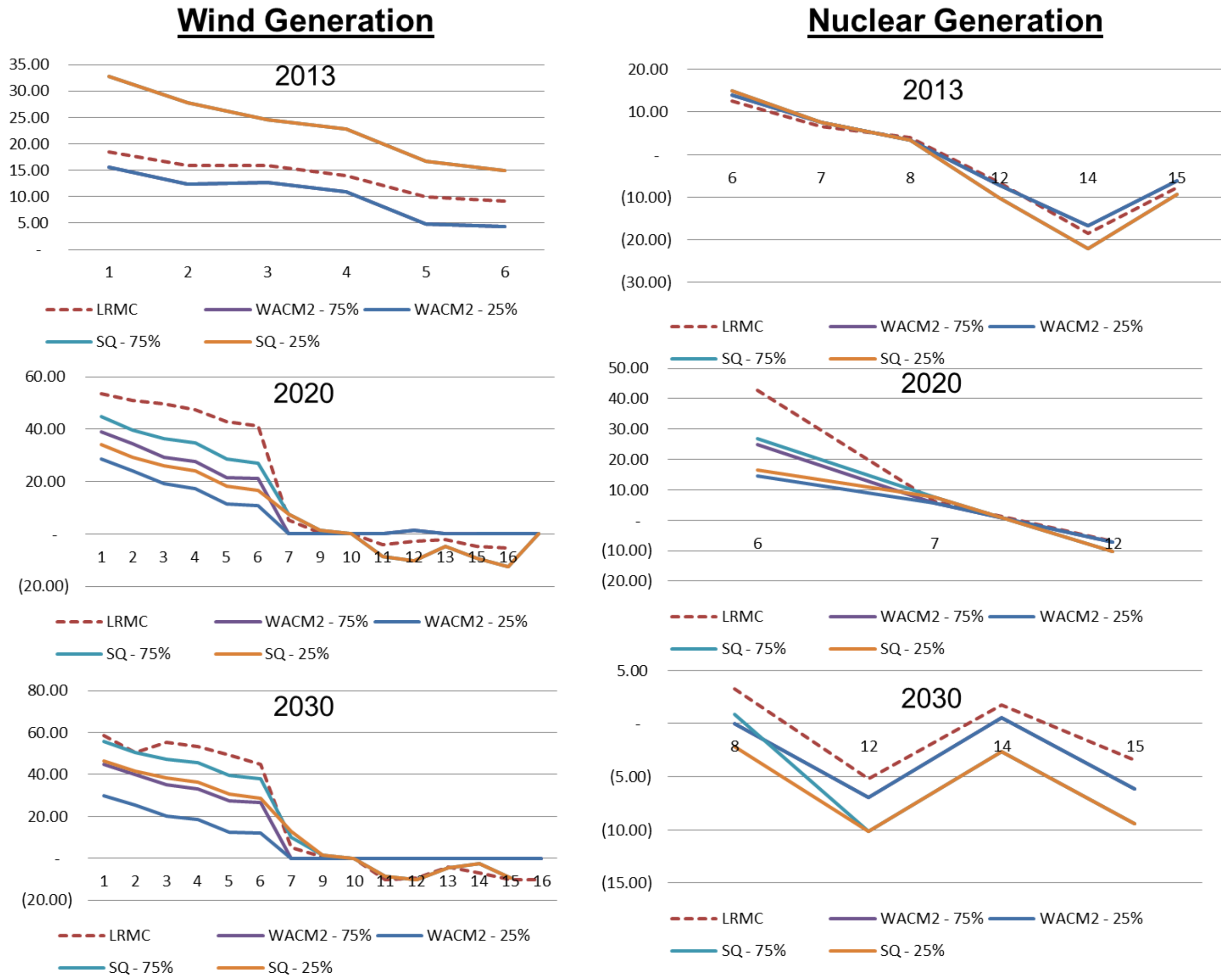
This analysis suggests that the WACM 2 model does not reflect the costs that intermittent generation technologies impose on the transmission system better than the status quo. Although the WACM 2 intends to improve on the status quo because the current methodology "*only recognises peak security as a driver of transmission investment – a form of investment that the NETS SQSS assumes is not driven by intermittent plant*",[41] the detailed design of the WACM 2 methodology has resulted in a set of charges that happen to be further from the LRMC of accommodating intermittent generation in northern zones than the status quo.

The right hand side of Figure 2.4 shows that in 2013, both charging models result in charges to nuclear plants that are close to LRMC. In 2020, there is still a close match between LRMC and both sets of charges in DTIM zones 7 and 12, but charges tend to be below LRMC for both charging models in zone 6. In 2030, WACM 2 charges are slightly closer to the LRMC than status quo charges.

Overall, our analysis suggests that the WACM 2 charging model does not result in charges that better reflect the LRMC of accommodating low carbon generation than the status quo. Although the status quo does not attempt to reflect the dual drivers of transmission investment, the detailed design of the WACM 2 methodology is such that the resulting charges are no closer to the LRMC of generation than charges resulting from the existing methodology.

[41] Ofgem, para 6.11.

Figure 2.4
LRMC vs Status Quo and WACM 2 TNUoS Charges (Wind and Nuclear)



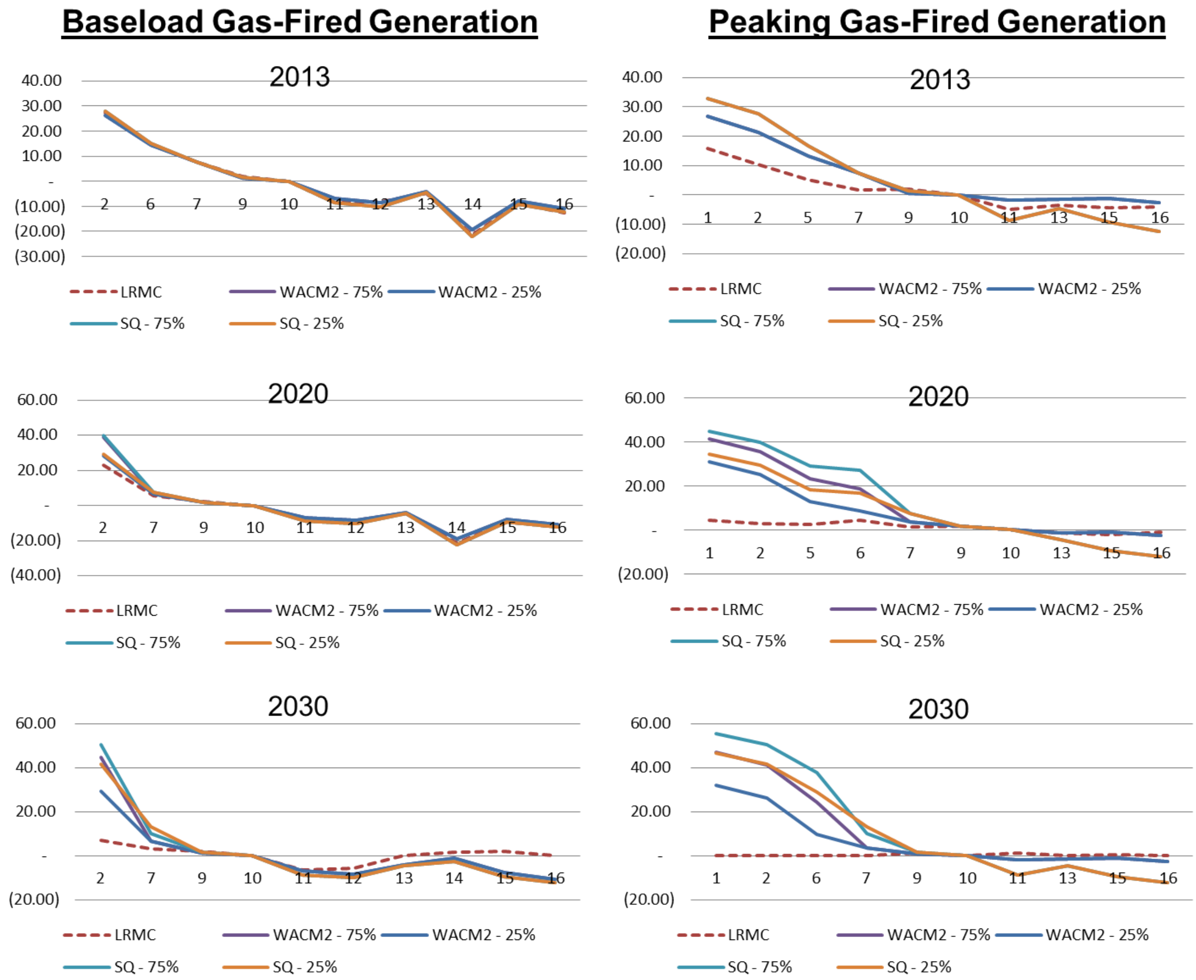
Source: Imperial College Analysis

2.3.6.2. WACM 2 charges are slightly closer to the LRMC that peaking gas-fired generators impose on the transmission system, but for higher load factor plants there is no difference compared to the status quo

Our analysis of the costs that gas-fired generators impose on the transmission system, presented in Figure 2.5 below, shows that there is a negligible difference in the TNUoS charges baseload gas-fired generators would pay under the WACM 2 and status quo charging models, and that both are close to LRMC. However, both charging methodologies result in charges that are materially above the costs of accommodating low load factor thermal generation in the north of GB.

Essentially, the investments to reinforce the network between Scotland and England and Wales are required to accommodate high flows of wind generation, usually in off-peak conditions. Thermal peaking plants rarely run in those conditions, so do not add to the constraints that these Scotland-England reinforcements aim to resolve. As a result, incremental peaking plants in Scotland have approximately a zero LRMC. Both methodologies would impose charges above LRMC on peaking plants operating in Scotland, and status quo charges would be higher (and further from LRMC) than WACM 2 charges.

Figure 2.5
LRMC vs Status Quo and WACM 2 TNUoS Charges (Baseload and Peaking Gas)



Source: Imperial College Analysis

2.3.6.3. Overall, our analysis suggests WACM 2 charges do not better reflect the LRMC that generators impose on the transmission system, but more analysis is needed to reach firm conclusions

This section shows a comparison of modelled WACM 2 and status quo TNUoS charges with the LRMC that generators of different types and in different locations impose on the transmission system. Although the WACM 2 intends to make the existing model more cost reflective, the detailed design of the WACM 2 methodology has resulted in a set of charges that, overall, are no closer to the LRMC of accommodating generation than the status quo.

However, while this analysis suggests that implementing the WACM 2 methodology will not improve cost reflectivity, it is not definitive. In order to reach robust conclusions regarding whether the WACM 2 methodology (or any of the other proposed methodologies) is more cost reflective than the status quo, Ofgem would need to perform the type of analysis presented in this section, with the following changes:

- Our analysis is based on a single generation and demand background, and a range of sensitivities should be considered before drawing firm conclusions; and
- We use a representation of the transmission system that, while intended to approximate the real British transmission system, could be replaced by a more detailed and accurate representation of the British transmission system.

So far in the Project TransmiT SCR process, neither Ofgem nor the working group has performed such an analysis, so the conclusions Ofgem has reached regarding the cost reflectivity of the WACM 2 charging model are unfounded.

2.4. Conclusions

Although the WACM 2 charging model reflects the costs of complying with the "demand security" standards imposed by the SQSS, our review and analysis suggests that the WACM 2 charging model does not reflect the costs of adhering to the other two transmission network planning requirements specified in the new SQSS:

- None of the analysis performed by the Workgroup or Ofgem has explicitly identified whether the binding drivers of transmission investment (and hence the costs that should be reflected in TNUoS charges) is the SQSS "economic criterion" or the investments prescribed by full CBA;
- Our illustrative examples (see Appendix B) show that the proposed charging model does not reflect the costs imposed on the TOs by the need to comply with the "economic criterion" in the SQSS. Hence, if adherence to the SQSS "economic criterion" is the binding driver of investment, then the WACM 2 charging model is not cost reflective;
- Neither the Workgroup nor Ofgem have performed any assessment of whether WACM 2 tariffs reflect transmission system costs prescribed by a CBA model better than those under the status quo or the alternative charging models Ofgem considered. Hence, if the obligation to perform additional transmission investments that are justified on the basis of a CBA is the binding driver of investment, then the analysis considered by Ofgem is inadequate to evaluate whether the WACM 2 model is cost reflective; and
- The analysis performed by the Workgroup and Ofgem that aims to assess whether the proposed charging models reflect the costs of investment to accommodate generation prescribed by a CBA model was flawed and incomplete. Our own comparison between incremental transmission costs (estimated using a CBA model) and WACM 2 suggests that the WACM 2 charging model is no more cost reflective than the status quo charges.

Our analysis therefore shows there is no objective basis for Ofgem's claim that the WACM 2 charging model would improve the cost reflectivity of transmission charging, so does not achieve the objective, set out in Ofgem's direction to NGET, to develop a methodology that *"better reflects the transmission investment framework set out in the NETS SQSS"*.[42] Also, it

[42] Ofgem para 2.10

does not better achieve the objectives of the Use of System Charging Methodology, set out in Condition C5 of National Grid's Licence, that charges should "*reflect, as far as is reasonably practicable, the costs incurred by the transmission operator*" because the methodology does not reflect the costs of providing the investments prescribed by the SQSS.

3. The Impact on Competition

When assessing the extent to which the proposed changes to the charging methodology enhance competition in the wholesale electricity market, Ofgem considers the following factors:[43]

- Potential for undue discrimination;
- Distributional impacts;
- Impacts on generator siting (entry and exit decisions);
- Impact on dispatch decisions; and
- Impact on stability, complexity and predictability of the commercial and regulatory arrangements.

I this chapter, we appraise the evidence put forward by Ofgem in relation to the impact on competition arising from the introduction of the WACM 2 charging model.

3.1. The Link Between Costs, Charges and Competition

3.1.1. Ofgem's belief that WACM 2 will enhance competition because it is more cost reflective than the alternatives is flawed

Ofgem's belief that WACM 2 will enhance competition is based largely on the assumption that it is more cost reflective than the alternatives:

> "*... to the extent that some of the CMP213 options are more cost reflective than others, our view is that these would more effectively promote competition all else being equal.*"[44]

As described in Chapter 2 above, the evidence upon which this assumption is based is not sound. Therefore, Ofgem's view that WACM 2 will enhance competition is also unfounded.

3.1.2. Ofgem's conclusion that WACM 2 model reduces potential undue discrimination relies on the belief that it improves cost-reflectivity

In paragraph 6.12 of the impact assessment, Ofgem suggests that the status quo is discriminatory as it does not accurately reflect the transmission costs imposed by individual generators. In particular, Ofgem notes that the Status Quo "*only recognises peak security as a driver of transmission investment – a form of investment that the NETS SQSS assumes is not driven by intermittent plant*"; and "*does not recognise that transmission investment also*

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43 Ofgem para 6.6

takes place to maintain an efficient level of constraint costs." In Ofgem's view, this results in discriminatory charging:

> "*Different plants drive different constraint costs and therefore have different impacts on the need for transmission investment. These differences are not reflected in the current methodology as all plants within a generation zone pay the same tariff*"

Ofgem argues that the options featuring Diversity 1 (which includes WACM 2) most closely reflect the decision-making process of TOs and would therefore "*reduce the discrimination present in the current charging methodology and promote more effective competition*."[45] This argument seems to be based on the assumptions that:

- a plant's annual load factor is a good proxy for its impact on transmission costs:
  - "*...plant's annual load factor is multiplied by the "year round" tariff... so that charges reflect different costs by different generators in a zone*";[46] and
- the Diversity 1 approach for representing the impact of high concentrations of low carbon generation on the supposed relationship between load factor and constraint costs is accurate:
  - "*Diversity 1 builds on the Original* [NGET proposal] *by recognising that the relationship between load factor and constraint costs…breaks down where there are high concentrations of low carbon generation*".[47]

For the reasons set out in Chapter 2, the evidence presented by National Grid to support a linear relationship between load factor and constraint costs is not robust. Furthermore none of the evidence presented considers the question of whether the "Diversity 1" approach accurately captures the relationship between the generation mix and constraint costs. Therefore, whilst it may be possible to devise a more cost-reflective, and hence less discriminatory, charging mechanism than the "status quo," the WACM 2 model as it stands does not achieve this aim.

3.2. Omitted Analysis of Distributional Effects

According to the results from NGET's modelling, all of the CMP213 options result in a redistribution of generator costs from the north to the south, such that the profits of southern generators fall and the profits of northern generators rise. According to Ofgem, this effect is most pronounced for the Original NGET proposal and the options featuring the Diversity 1 approach.[48] For instance, Figures 4 and 5 in the Ofgem paper, reproduced below as Figure 3.1, illustrate that between 2021 and 2030, total generator profits in the south of England and Wales fall by over £400 million per annum.

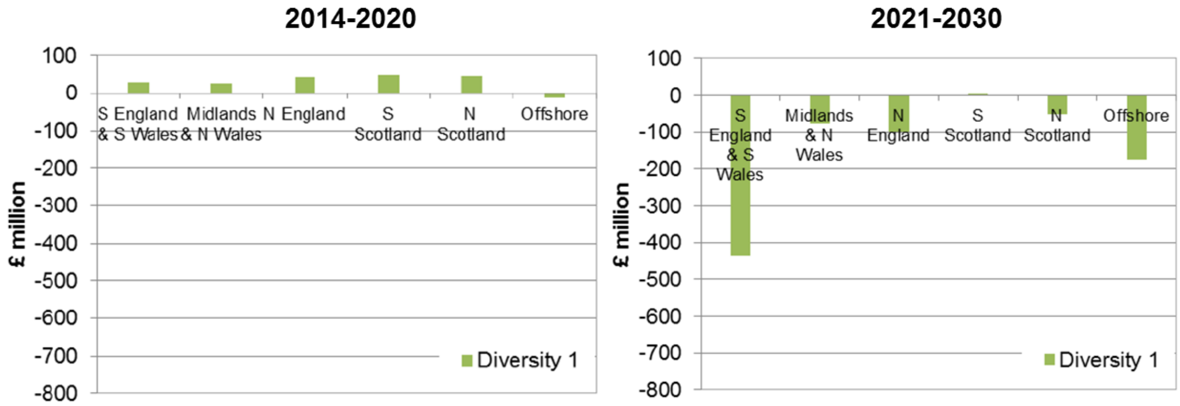
45 Ofgem para 6.14

46 Ofgem para 6.13, bullet point 1

47 Ofgem para 6.13, bullet point 2

48 Ofgem para 6.16,

Figure 3.1
Average Annual Change in Total Generator Profits, Relative to Status Quo (Diversity 1)



Source: Ofgem, Figures 4 and 5.

Ofgem claims that the "*redistribution of costs is not disproportionately high for any of the CMP213 options and is appropriate in order to improve the cost reflectivity of charges*".[49] It is not clear how Ofgem has reached the conclusion that the redistribution of costs is not "disproportionately high", as the analysis in the Impact Assessment is incomplete:

- Firstly, Ofgem has not identified what degree of distributional impacts it would consider to be "disproportionately high". Decisions by Ofgem to redistribute profitability between industry participants impose costs on the power system, as they increase the perception of regulatory risk, and thus increase the cost of capital faced by investors in the British energy sector. Any decision to implement a charging model with significant distributional effects therefore needs to weigh the benefits of the scheme against the extra costs of increased regulatory risk, which ultimately affects financing costs, and hence costs to consumers.
  - To put this effect into perspective, suppose on the one hand that the substantial redistribution amongst investors caused by the introduction of the WACM 2 charging model increases the cost of capital by as little as 25 basis points. Further suppose that the UK energy sector requires around £100 billion of investment over the period to 2020. In these conditions, the increase in regulatory risk would raise power sector costs by around £2 billion between 2014 and 2030.[50] This effect would outweigh any welfare gain arising from the implementation of the WACM 2 model shown by Ofgem's modelling results in Table 9 of its Impact Assessment.
- Secondly, the Impact Assessment shows bar charts illustrating the annual changes in total generator profits relative to the status quo in particular regions. However, regional

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49 Ofgem prar 6.19

50 This calculation assumes the £100 billion of investment takes place gradually between 2014 and 2020, and no further investment is required thereafter. We calculate the difference in financing costs in each year due to the assumed increase in the real pre-tax WACC from 10.00 per cent to 10.25 per cent, and then calculate the NPV impact on power sector costs between 2014 and 2030 using a real WACC of 3.5%, which is the prescribed rate for social cost-benefit analysis in the public sector in the UK.

redistributions of profits would not matter if all generation companies were geographically diversified. To fully analyse distributional effects, Ofgem needs to sum up impacts by industry player. Such a calculation of redistributions among industry players would be relatively straightforward as published data sources, such as the National Grid Seven Year Statement, provide detailed information on plant ownership. Summing up each industry participant's TNUoS charges and/or profitability (i.e. across plants) using data from National Grid's modelling, and applying an appropriate discount rate, would indicate how much value would be redistributed by the alternative proposals to reform TNUoS charges.

3.3. Distortions to Dispatch

Both the original NGET proposal and WACM 2 use annual load factor (ALF), averaged over five years with the highest and lowest values removed, to scale generators' liability to pay year-round charges. The Industry Workgroup has proposed an alternative 'hybrid' option for the ALF which would allow generators to choose between the average 5 year historical average or a forward looking annual forecast that would entail a reconciliation at the end of the year, including a penalty if the forecast turns out to be inaccurate.

Ofgem believes the hybrid option may harm competition by distorting behaviour such that a less efficient plant ends up generating instead of a more efficient plant in order to avoid a penalty for inaccurate forecasting.[51] However, as our worked example below shows,[52] any method that links charges to load factor, including the 5 year averaging approach, has the potential to affect a plant's dispatch decisions.

Consider a 200MW generator located in a zone with a year round shared tariff of £1/kW. Suppose, for simplicity, that this generator has been running with a constant load factor of 70 per cent for the past five years but decides to decrease its annual output by 100GWh in the current year (Year 1) and the next (Year 2), before returning to its old running regime in all subsequent years.

Table 3.1
Illustration of the Link Between Dispatch Decisions and TNUoS Charges Under WACM 2

Year	-4	-3	-2	-1	0	1	2	3	4	5	6	7
Load Factor	70.0%	70.0%	70.0%	70.0%	70.0%	64.3%	64.3%	70.0%	70.0%	70.0%	70.0%	70.0%
Output (GWh)	1226.4	1226.4	1226.4	1226.4	1226.4	1126.4	1126.4	1226.4	1226.4	1226.4	1226.4	1226.4
5 Year Historic ALF	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	68.1%	68.1%	68.1%	68.1%	70.0%
Year Round *Shared* Charge (£)	140,000	140,000	140,000	140,000	140,000	140,000	140,000	136,195	136,195	136,195	136,195	140,000

51 Ofgem para 6.23

52 This worked example is based on an example from a paper presented by a member of the Industry Workgroup , describing the link between 5 year historic load factor and short run marginal costs (See Annex 14.1 of the FMR)

As the above table shows, the five year historic annual load factor would not be affected until Year 3, as the highest and lowest values are removed from the average. The ALF would fall to 68.1% ((70 + 70 + 64.3)/3) in Years 3 to 6 before returning to 70% in Year 7. Thus, adjusting output for just two years has an impact on the ALF, and hence TNUoS charges, for four years. Assuming a discount factor of 10 per cent, the net present value of the change in TNUoS charges arising from the two-year 100GWh change in output is:

$$NPV = £1/kW \times (70\% - 68.1\%) \times \left(\frac{1}{(1+10\%)^2} + \frac{1}{(1+10\%)^3} + \frac{1}{(1+10\%)^4} + \frac{1}{(1+10\%)^5}\right) \times 200{,}000\ kW$$

$$NPV\ Reduction\ in\ TNUoS = £10{,}965$$

Thus, linking TNUoS charges to the historic load factor may distort dispatch decisions by creating an incentive to reduce output in order to make a saving on transmission-related costs. Changing from the status quo (with TNUoS charges solely based on capacity) to any of the proposed alternatives that link TNUoS charges to load factor may therefore reduce the efficiency of dispatch and harm competition. It is also inconsistent with current proposals to delink BSUoS charges from generators' production to avoid distorting cross-border trade in the EU (see Section 6.1).

3.4. Instability of the TNUoS Charging Regime

Over many years, generators have taken locational investment decisions in response to the signals conveyed through the existing charging model. Furthermore, Ofgem acknowledges that *"The current transmission charging regime has served consumers well by promoting the efficient use of the networks, and facilitating effective competition in generation and supply*".[53]

Ofgem does not consider the longer-term impact on future investment incentives of its decision to change TNUoS charges when it considers the "*impact on stability, complexity and predictability of the commercial and regulatory arrangements*".[54] Changes to the current regime, without compensation mechanisms, undermine future incentives to invest efficiently in response to future charging signals, as investors will place less weight on the signals conveyed through TNUoS charges when taking investment decisions.

In relation to the extra complexity of the proposed charging model, Ofgem acknowledges that the addition of further components to the transmission tariff through the introduction of WACM 2 will make charges more complex and increase the level of "potential volatility" relative to the status quo.[55] According to Ofgem's reasoning, this aspect of the new methodology would have a negative impact on competition:

[53] Project TransmiT, A Call for Evidence, Ofgem, 22 September 2010.

[54] Ofgem para 6.6.

[55] Ofgem para 6.25 and para 6.28.

> "*More stable, predictable charges reduce risk to generators and suppliers. This reduces barriers to entry and makes it easier for smaller generators and suppliers to compete with large competitors.*"[56]

However, Ofgem seems to place little weight on this problem in its appraisal, we assume because it sees cost reflectivity as more important.

3.5. Conclusions

As discussed in this chapter, we have identified several problems with both the proposed reforms that make them detrimental to competition, and the evidence Ofgem has relied on to assess the likely impact on competition:

- **Potential for undue discrimination:** Ofgem's belief that WACM 2 will reduce the potential for undue discrimination is based largely on the assumption that it is more cost reflective than the alternatives. As described in Chapter 2, the basis of evidence from which Ofgem draws this conclusion is incomplete and flawed.
- **Distributional impacts:** Ofgem's Impact Assessment does not accurately estimate the distributional effects between market participants that will result from these reforms, and does not account for the costs of redistributing value around the electricity sector in its appraisal of the alternative charging models against the status quo.
- **Impacts on generator siting (entry and exit decisions):** Any improvements in the efficiency of generator siting decisions depend on whether the proposed charging model is more cost reflective than the alternatives. As described in Chapter 2, Ofgem has not demonstrated that the proposed charging model is more cost reflective, and moreover, our own analysis suggests it is less cost reflective than the status quo.
- **Impact on dispatch decisions:** Linking the year-round charge to load factor will increase the variable costs of dispatch, as the example in this chapter illustrates. This could distort dispatch patterns and distort trade with neighbouring markets (see Chapter 6).
- **Impact on stability, complexity and predictability of the commercial and regulatory arrangements:** Ofgem does not consider the longer-term impact on future investment incentives of its decision to change TNUoS charges. Changes to the current regime, without compensation mechanisms, undermine future incentives to invest efficiently in response to future charging signals, as investors will place less weight on the signals conveyed through TNUoS charges when taking investment decisions.

[56] Ofgem para. 6.24

4. Review of Quantitative Evidence

Ofgem's Impact Assessment does not rely heavily on the quantitative modelling undertaken by National Grid,[57] which it summarises in Chapter 4 of the Impact Assessment, placing more emphasis on discussions of cost reflectivity. However, the impact assessment does refer to the modelling in some areas as evidence to justify its decision. For example, Ofgem uses modelling results to support its argument that the modifications will reduce customers' bills, and are therefore consistent with Ofgem's obligation to protect present and future customers.[58] Ofgem also highlights the fact that, in National Grid's model all of the new tariff options require lower levels of carbon support to meet 2030 decarbonisation targets, and cites this as evidence that the CMP213 proposals "*should further promote sustainable development.*"[59]

As we describe in this chapter, however, there are a number of problems with National Grid's modelling, some of which Ofgem itself recognises and were pointed out by the consultants Ofgem appointed to review the modelling.[60]

4.1. Problems with the Redpoint Modelling Framework

The modelling performed by National Grid uses the same platform and tools it developed in conjunction with Redpoint during the Project TransmiT process. In a 2012 NERA report, which appraised the Ofgem "options for change" paper, we provided a detailed critique of this modelling platform. Given that this modelling platform appears to have largely remained the same, we assume that the problems we previously highlighted have not been addressed and continue to undermine the robustness of the results produced.

A more detailed discussion of these problems is available in our 2012 report, but two key structural problems with the modelling approach are:[61]

- Redpoint's "imperfect foresight" modelling does not constitute a coherent economic framework. By assuming that investors adopt short (five year) planning horizons, it assumes that investors take decisions that systematically ignore the changes that are already expected to occur in the future, such as trend increases in fossil fuel prices or the general trends of increasing TNUoS charges and foreign-owned low carbon generators.
- The Electricity Scenario Illustrator (ELSI) model is not a reliable tool for forecasting the evolution of the GB power market, because it does not account for the impact of

[57] CMP213 Impact Assessment Modelling Report. National Grid, 25 July 2013

[58] Ofgem para6.79

[59] Ofgem para 6.69

[60] Ofgem Para 4.11

[61] The following report provides a more detailed discussion of the shortcomings of the Redpoint modelling: Project TransmiT: Ofgem's Assessment of Options for Change: A Review Prepared for RWE npower, NERA Economic Consulting, 14 February 2012, Appendix A.

generator dynamic constraints, such as ramp rates and minimum stable load, on prices and dispatch. Therefore, it is likely to understate the volatility of power prices and the value of flexible generation technologies, such as gas-fired OCGTs; and to overstate the value of less flexible generation technologies such as CCS.

4.2. Specific Problems with National Grid's Modelling

4.2.1. The National Grid modelling fails to conduct sensitivity analysis

The modelling conducted by National Grid suggests that the social welfare improvements that arise as a result of introducing the WACM 2 charging model (or the other variants) are relatively small, with the change in the TNUoS charging regime resulting in only modest changes in generators' locational decisions compared to the status quo. For instance, the Baringa review of the National Grid modelling results states that "*the results demonstrate that the differences in transmission charges between Status Quo and Improved ICRP/Original have only a relatively small impact on overall power sector costs (in the context of the total power sector costs)*".[62]

Given this finely balanced conclusion about the welfare implications of the alternatives under consideration, there would have been merit in conducting some sensitivity analysis to identify the factors on which the case for revising transmission charging arrangements depends. For instance, the modelled effects of changes in TNUoS charges may depend on:

- Assumptions on future commodity and CO_2 prices;
- Assumptions on the development of arrangements for energy pricing, e.g. by considering a scenario where the UK introduces zonal pricing to comply with the EU Target Model;
- Demand growth, e.g. due to the extent of electrification of heat and transport;
- Long-term decarbonisation targets (e.g. 100g/kWh by 2030, vs. 50g/kWh);
- The costs of developing HVDC bootstrap links;
- The constraints on renewables build rates and the availability of sites for low carbon and conventional generation; and
- The development of new interconnectors with neighbouring markets.

Without such sensitivity analysis, Ofgem's conclusions that the WACM 2 charging model would enhance social welfare, be in the interests of consumers and enhance competition cannot be justified on the basis of the quantitative modelling presented to it.

4.2.2. National Grid's modelling results are sensitive to assumptions made about future factors that are highly uncertain

The Baringa review of the National Grid modelling notes that the modelling results used to compare the status quo with the WACM 2 model, and the other variants, exhibit differences in costs that cannot necessarily be attributed to differences in TNUoS charges:

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62 CMP213 Modelling: Review of CMP213 Impact Assessment Modelling for Ofgem, Baringa, 31 July 2013, page 71.

"*The relatively subtle differences in transmission charges can be dominated by other effects, and the differences between Original and Status Quo should be considered in the context of these other factors. We believe these factors fall into four broad categories:*

1. *The problem is heavily constrained by the availability of sites for new low carbon generation, and deployment rates for renewables technologies, and hence the relatively subtle changes in locational signals under Original have less of an impact on low carbon investment than might otherwise be the case.*
2. *The differential support levels for low carbon generators under the Renewables Obligation and assumed under EMR are a much stronger driver of investment behaviour than relatively small changes in transmission charges.*
3. *The lumpiness of onshore transmission reinforcement can favour one option if the reinforcement is closer to optimal sizing under that option.*
4. *Constraint costs may increasingly become 'polluted' by low carbon support payments with low carbon generators bidding below their true short run costs in order to continue to receive support payments (which we assumed would also be the case under Contracts for Differences based on the Government's EMR publications).*"[63]

It is also likely that the modelling results for the Diversity tariffs will be highly sensitive to the choice of low carbon/carbon classifications which, as the industry workgroup noted "*may need to be revisited after the UK Government's Electricity Market Reform (EMR) process has concluded, as this may affect the bid price of generation plant substantially*."

These above factors further increase the need to perform sensitivity analysis before drawing firm conclusions on the expected quantitative impact of the proposed charging models.

4.2.3. Cost savings resulting from removing the status quo are exaggerated because RES penetration is highest in the status quo case

Following the "stage 2" part of the Redpoint modelling approach and Ofgem's assumption that government can adjust RES subsidies to achieve the level of penetration required by policy decisions, National Grid has adjusted CfD levels to ensure that the level of renewables penetration is similar across the scenarios it modelled. However, it appears that the modelling framework does not allow National Grid to perform this calibration precisely, and Figure 4.1 shows that small differences remain between the scenarios, with the highest level of RES penetration in the status quo scenario, particularly from 2025 onwards. Tables 10 and 11 of the Ofgem Impact Assessment suggest that RES penetration in the status quo is 30.4 per cent in 2020 and 32.8 per cent in 2030 as compared to 29.6 per cent and 31.3 per cent penetration in 2020 and 2030, respectively, in the Diversity 1 scenario.

[63] CMP213 Modelling: Review of CMP213 Impact Assessment Modelling for Ofgem, Baringa, 31 July 2013, page 96.

Higher levels of RES penetration will tend to increase the modelled power sector costs of the status quo compared to the alternatives because RES technologies tend to be more expensive than conventional alternatives.[64] Although it would require detailed modelling to estimate the impact accurately, we have performed the following illustrative calculation, shown in Figure 4.2, that shows the extra cost is approximately the same as the savings in power sector costs Ofgem attributes to the adoption of the WACM 2 charging model in place of the status quo:

- The levelised costs of onshore and offshore wind generation, as estimated in a recent study for DECC by Mott MacDonald are £94/MWh and £157-186/MWh, respectively, whereas the levelised cost of a gas-fired CCGT is £80/MWh.[65] (All figures in real 2009 terms.)
- Hence, the difference between the total generation costs of wind (based on the mid-point between onshore and offshore costs), and the cost of generation with a gas-fired CCGT is around £53/MWh. Inflating this difference from 2009 to 2012 prices gives a difference of £60/MWh in 2012 prices.[66] Multiplying this cost difference by the difference in RES production implied by the annual energy demand assumed in National Grid's modelling gives the extra cost of higher RES penetration shown by the green line in Figure 4.2.
- We estimate that this difference in costs would amount to around £2.12 billion in NPV terms (discounting at a 3.5% real WACC to 2013). This compares to a total NPV difference in power sector costs of £1.949 billion that Ofgem attributes to the introduction of the WACM 2 model.

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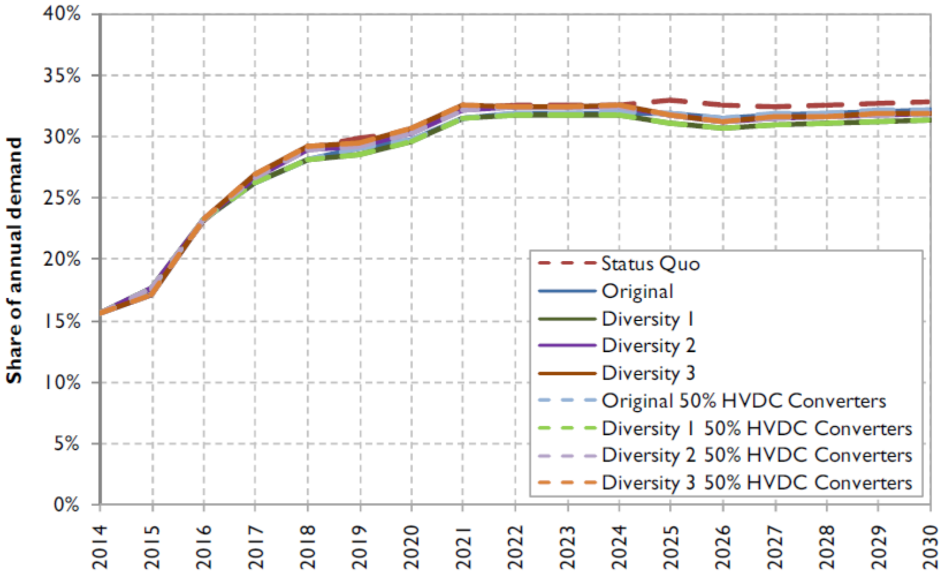
64 The higher power sector costs as a result of higher renewables penetration in the status quo is noted in the Baringa review of National Grid's modelling. See: CMP213 Modelling: Review of CMP213 Impact Assessment Modelling for Ofgem, Baringa, 31 July 2013, page 66.

65 UK Electricity Generation Costs Update, Mott MacDonald, June 2010, Section 7.2.

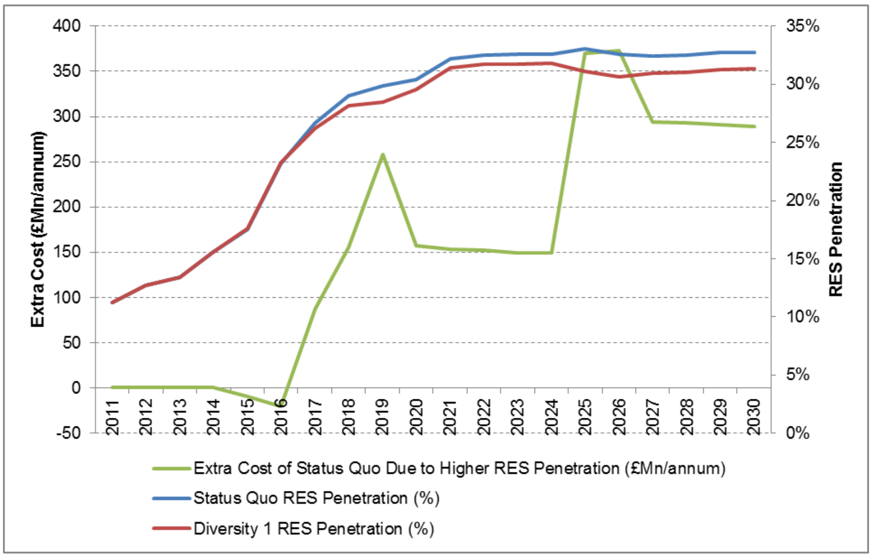
66 Inflation in All Items RPI from 2009 to 2012 of 13.57% (cumulative). Source: ONS.

Figure 4.1
Share of RES Penetration Across National Grid Modelling Scenarios



Source: NG Modelling Report, Figure 2.2.

Figure 4.2
Estimated Extra Costs of Assuming Higher RES Penetration in the Status Quo Case



Source: NERA Analysis of data from National Grid and Mott MacDonald.

4.2.4. There is no sound basis for the increase in capacity margins and reduction in power prices following replacement of the status quo

NGET's modelling predicts that customer bills would be lower under WACM 2 by £4.5 billion in the period 2021 to 2030 and £3.8 billion lower for the whole period from now to 2030 (in NPV terms). The modelled differences in consumer bills arising from the charging options seem to be mainly due to differences in capacity margins, and hence power prices. However, as described below, it is likely that National Grid's model miscalculates the impact of the proposed changes to the TNUoS charging on prices. Thus the quantitative evidence used by Ofgem to support their view that WACM 2 "*is in the long term consumer interest*" is not reliable.

NGET's modelling shows that capacity margins are lowest in the status quo scenario. Ofgem's Impact Assessment notes that the increase in capacity margins under the alternative approaches reduces wholesale purchase costs, and hence costs to the consumer.[67] However, this result is not sound.

First, following the introduction of the EMR capacity mechanism, the derated reserve margin will effectively be selected centrally.[68] The capacity market will then clear to ensure that this level of derated capacity margin is provided. Hence, assuming changes to TNUoS charges do not affect DECC's decision over what derated reserve margin the market requires, the finding that removing the status quo would increase derated reserve margins in the long-run is not robust. In other words, it appears that the modelling does not properly account for the prevailing market arrangements over the modelling period.

It appears from the Redpoint review of the National Grid modelling work that this results from the simplistic way in which the Redpoint modelling framework adjusts subsidy levels in "stage 2" of the modelling to achieve environmental targets:[69]

> "*In meeting the 100g/kWh target in 2030, the capacity mix under the Original run contains more gas CCS and less offshore wind. This has a positive impact on security of supply from 2025 onwards since gas CCS is a more flexible technology than offshore wind, and thus has a higher de-rating factor (90% for gas CCS compared to 15% for offshore wind). This difference in the long term is a result of the Stage 2 CfD strike price setting approach, which targets the same decarbonisation level across runs but not the same security of supply.*"

> "*In general, generation cost savings are realised under runs with lower levels of renewable penetration, or where expensive offshore wind is replaced by onshore wind or gas CCS.*"

As we discuss in our previous report, the Redpoint framework has an extremely simplistic method of adjusting subsidies to meet government targets, as it assumes subsidy levels are uniformly scaled down to achieve targets, i.e. it does not allow for the subsidies offered to different technologies to rise or fall by different amounts.[70]

It is possible that, following changes in TNUoS charges, the derated capacity margin could change in response to changes in generation costs. In an efficiently planned power system,

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67 Ofgem para 4.83

68 Electricity Market reform: Capacity Market – Detailed Design Proposals, DECC, 27 June 2013, Page 14

69 CMP213 Modelling: Review of CMP213 Impact Assessment Modelling for Ofgem, Baringa, 31 July 2013, pages 62 and 88.

70 Project TransmiT: Ofgem's Assessment of Options for Change: A Review Prepared for RWE npower, NERA Economic Consulting, 14 February 2012, Section A.4.

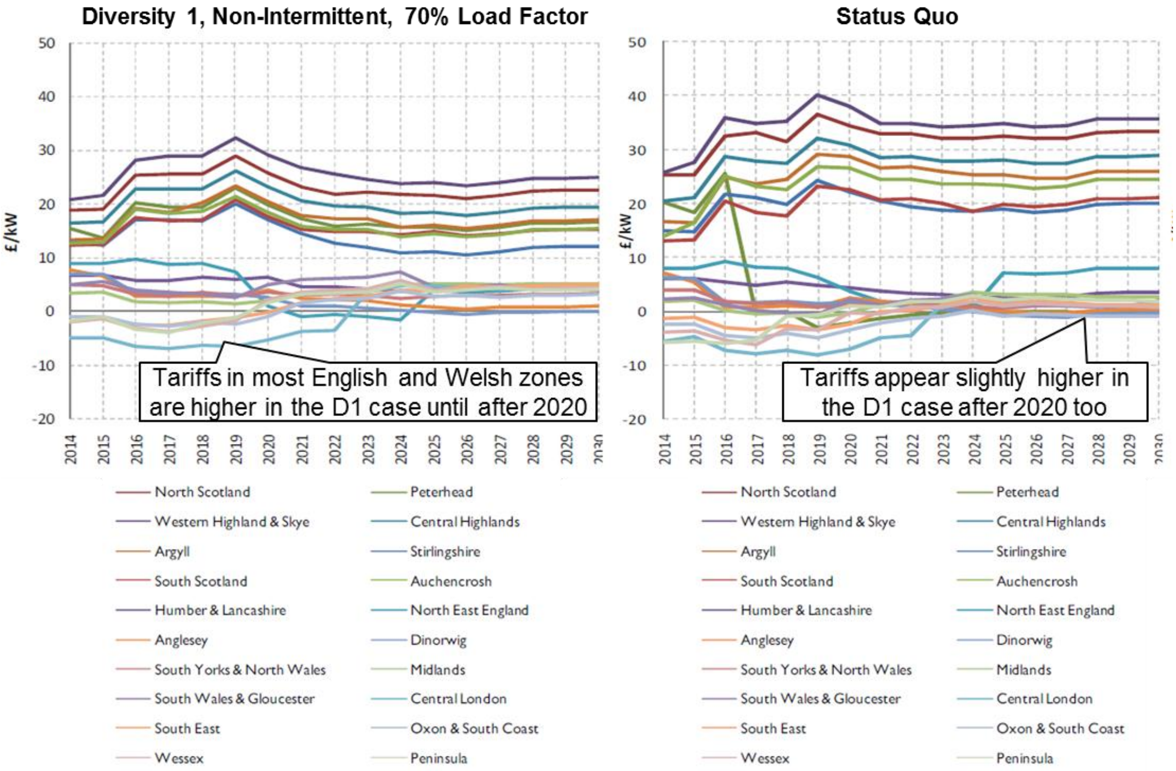
the derated capacity margin will depend on the trade-off between the costs of constructing new capacity, keeping existing capacity on the system, and shedding load. Accordingly, the proposed structure for the CPM links the amount of capacity procured to the costs of new entry; more capacity will be procured if the costs of capacity fall.

In this hypothetical context, to confirm whether the increase in capacity margins is robust, it would be necessary to evaluate whether the costs of new entry falls as a result of introducing the new charging models. If so, then theory suggests that efficient capacity margins should rise and long-term power prices should fall.[71] In general, the cost of new entry will be determined by the marginal technology required to meet demand, which National Grid's modelling suggests is gas-fired CCGT capacity in the period to 2020, and CCS capacity thereafter.

In both the status quo and Diversity 1 modelling scenarios, nearly all new CCGT and CCS capacity connects to the system in England and Wales. As Figure 4.3 shows, from a simple graphical comparison of the charges published by National Grid, the modelled TNUoS charges for a 70 per cent load factor non-intermittent generator operating in England and Wales are slightly lower in the status quo than in the Diversity 1 case. This suggests that the cost of new entry has not fallen, but rather increased slightly as a result of introducing the Diversity 1 approach. This is inconsistent with the finding that the modelled capacity margin increases and power prices fall.

[71] For instance, the report Ofgem commissioned from the Universities of Strathclyde and Birmingham states that: "*The impact of transmission charges on international competition via wholesale electricity prices should be considered; broadly speaking, the charges paid by generators will have to be added to wholesale prices if those generators are to recover their costs.*" Source: Bell, Green, Kockar, Ault and McDonald, Project TransmiT: Academic Review of Transmission Charging Arrangements, Version 3.0, 3 May 2011, page 12.

Figure 4.3
National Grid's Modelled TNUoS Charges (Status Quo and Diversity 1 Cases)



Source: National Grid

Although the cost of entry has not changed materially, as discussed above, power prices have fallen materially, and accordingly, the modelling suggests that generators make less profit under WACM 2 than in the status quo case. Figure 5 in the Ofgem Impact Assessment suggests that, during the 2020s, generators across the country as a whole earn between £800Mn and £900Mn per annum less profit (i.e. producer surplus) in the WACM 2 case than the status quo, with the largest differences towards the south of the country.

This result suggests that in at least one of these cases, generators are either earning revenues in excess of or below their costs, including a normal return on capital, and that the difference in power prices is itself artificial. That is, in reality, generators will continue to enter the market until any excess profitability is eroded. Likewise, generators will not enter the market if they cannot earn their normal return on capital. Hence, the power prices emerging from two scenarios with significant differences in profitability are unlikely to be comparable. Hence, statements in Ofgem's Impact Assessment that the WACM 2 model will benefit consumers by reducing their bills are not supported by the modelling.

> "*…even if the long term benefits [of WACM 2] were halved there would still be a £1.6 billion net benefit to consumers over the period to 2013. This is consistent*

> *with our view that a more cost reflective methodology drives a more efficient system in the long run which will deliver consumer benefits.*"[72]

4.2.5. There is no material difference between the environmental performance of the alternative charging models

As demonstrated by the "stage 2" modelling approach adopted by National Grid, there is no material difference between the alternative charging models' ability to help meet government targets to increase the penetration of renewables and reduce CO_2 emissions. We therefore agree with Ofgem's assumption that government subsidies can be adjusted to achieve targets, taking the TNUoS charging regime as given.[73]

4.3. Conclusion

This chapter discusses a range of problems we have identified with the National Grid modelling, some of which were highlighted by Ofgem's own consultants. These flaws mean that the quantitative analysis Ofgem conducted does not provide a robust basis on which to justify a change in the transmission charging methodology, and perhaps explains the focus in Ofgem's Impact Assessment on qualitative evidence concerning cost reflectivity.

Ofgem recognises to some extent the limitations of its quantitative modelling, noting that modelling the impact of new TNUoS arrangements is "*necessarily complex but at the same time must make simplifying assumptions.*"[74]

[72] Ofgem para 6.81

[73] Ofgem para 6.68

[74] Ofgem para 4.10

5. Implementation Date

Ofgem is minded to implement the new methodology from the earliest possible date of 1 April 2014. Having considered later implementation dates, Ofgem justifies the choice of an early implementation on the basis that it would "*avoid further delay and move quickly in what we consider to be the right direction*".[75] Ofgem's desire to see the new charging model implemented quickly, however, will not result in more efficient outcomes than delaying implementation by a year, and may have other downsides by creating unnecessarily large distributional effects, as we discuss below.

5.1. Efficiency Impacts from an Early Implementation Date

Even if the new charging model is more cost-reflective,[76] it is almost certainly too late for any decision by Ofgem taken in late-2013 to affect the locational decisions of new plants that are planned to come online during the charging year 2014/15 because of the construction lead times involved.

In any case, even if it were possible to change locational decisions for new plants coming online in 2014/15, implementing the new charges in 2014/15 rather than 2015/16 or 2016-17 would probably have little impact on those decisions. This is because generators will expect the new TNUoS regime to apply for a number of years, and their locational decisions will place relatively little weight on the charges applying in the first year or two of the plant's operation. Thus, Ofgem's suggestion that *"earlier implementation would maximise the available benefits from a change and realise them sooner"*[77] is misleading.

In addition to influencing locational decisions for new plants, the new charging model might signal that it is efficient for some plants to retire (assuming the new model is more cost-reflective) earlier or later than they would under the status quo. As Baringa notes, this is reflected in NGET's modelling, which shows earlier retirements under all of the new methodologies for a total of 1.3 GW of CCGT capacity in North England and Midlands & North Wales.[78]

However, just as 2014/15 is too soon to influence locational decisions for new plants, changing tariffs in 2014/15 will have little effect on retirement decisions taken in that year. Specifically, generators must give a minimum notice of one year and five days before making

75 Ofgem para 6.101

76 Note, the analysis in the preceding chapters suggests this is not the case. We consider this possibility only for the purposes of analysing the choice of implementation date.

77 Ofgem para 6.101

78 Review of CMP213 Impact Assessment Modelling for Ofgem, Baringa, 31 July 2013, Page 85

reductions in TEC.[79] If generators reduce TEC immediately, i.e. without giving this period of notice, they are liable to pay "cancellation charges" of up to £17/kW.[80]

It is therefore conceivable that immediate implementation of the new methodology might lead some generators to reduce their TEC immediately to avoid a significant increase in tariffs next year if they would rather close early, pay the cancellation charge and forgo a year of earnings from sale of energy into the wholesale market. However, many generators will see TNUoS payments in 2014/15 as essentially a sunk cost that it would not be profitable to shut the plant to avoid. Hence, the earliest date on which they would reduce capacity in response to the signals conveyed through a new charging model is 2015/16. Implementing new TNUoS charges in 2014/15 rather than 2015/16 would therefore achieve little efficiency benefit by bringing forward retirement dates.

5.2. Exacerbating Distributional Effects

While early implementation of the new tariffs would not achieve efficiencies by changing generator location or retirement decisions, it would add to the distributional effects of the scheme.[81] Although Ofgem has failed to quantify distributional effects by industry player (see Section 3.2), our own analysis that we have redacted from this confidential report suggests that individual industry players could experience increases in TNUoS charges for their generation portfolios of up to £xx million per annum or reductions in TNUoS of up to £xx million per annum. [We need to decide whether to include this, once the figures are finalised.] These effects might be expected to reduce over time as generators have the opportunity to adjust their locational decisions in response to changes in TNUoS. However, as described above, it is not possible for generators to avoid changes in TNUoS charges if they occur in 2014/15.

5.3. Conclusion

In summary, the implementation of the new TNUoS charging model in 2014/15 would create significant additional windfall gains and losses compared to a later implementation date, and even if the new model is more cost reflective, it would achieve no extra efficiency benefit as 2014/15 is too soon for generators to increase or decrease their capacity.

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79 The "Post Connection User Commitment", set out on page 11 of National Grid's on Connect and Manage Guidance document, states that a TEC Reduction Charge will be incurred if the generator does not give notice for the remainder of the current financial year and the next financial year (i.e. a minimum period of one year and five days).

80 2012/13 Wider Cancellation Charge Statement (Version 1) Effective from 1st October 2012, Based Upon: User Commitment Methodology contained within Section 15 of the Connection and Use of System Code, Section 1.3.

81 Distributional effects are exacerbated by the very fact that generators cannot adjust capacity in response to the changing tariff incentives.

6. Interactions with Other Elements Market Design

6.1. Consistency with the EU Target Model

European legislation requires Ofgem to pursue a number of objectives such as "promoting cost-effective, secure and efficient network development and avoiding unjustified discrimination".[82] Ofgem believes that WACM 2 best achieves these aims and is aligned with the "*European direction of travel*" which "*appears to be towards more cost reflective pricing*".[83] As described in Chapter 2, we have identified a number of problems with Ofgem's claim that the proposed WACM 2 charging model is more cost reflective, which would also undermine its claim that the reform is aligned with the "*European direction of travel*".

However, Ofgem's Impact Assessment fails to consider interactions with the need to introduce the EU Target Model. The EU Target Model may introduce zonal energy pricing in some form. If it results in market splitting then, effectively, a significant proportion of constraint costs could be priced through regional variation in the wholesale energy price within Great Britain. The current TNUoS charging model, or the proposed WACM 2 alternative, might therefore require revision as the British market is brought into line with other neighbouring markets.

The evidence in the FMR document that the WACM 2 model is cost reflective, although flawed in some respects, is based to a large degree on evidence that the charging model reflects incremental constraint costs. The analysis presented is inconsistent with a scenario in which a significant share of constraint costs are priced into regional variation in energy prices. Also, the modelling discussed in Chapter 4 assumes a uniform national wholesale energy price. The possibility of market splitting means it would appear prudent to at least consider a sensitivity to this key change in trading arrangements before reforming the TNUoS charging regime.

Moreover, possible inconsistencies between the Target Model and the WACM 2 (or status quo) charging models mean that further reform of infrastructure access charges might become necessary in the coming years. Changing the TNUoS charging regime in April 2014 and then again once the Target Model is implemented would create instability of charges, add to perceived regulatory risk, and undermine any case for reform on the basis that the WACM 2 model is more cost reflective than the alternatives as there will be little time for efficiency benefits to be realised.

Ofgem's failure to consider the implications of "market splitting" runs contrary to its recent decision to reject BSC Modification Proposal P229, in part on the grounds that changes in EU policy be introduced before the supposed benefits of the proposal could be realised:[84]

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[82] Ofgem para 6.92

[83] Ofgem para 6.94

[84] Decision on "Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses scheme (P229)", Ofgem, 28 September 2011, page 6.

> *"the P229 proposals are being decided in the context of a changing external environment, in which an approved transmission losses proposal may be superseded before the full benefits have been realised. In particular, at a European level, there is an active debate for greater integration of electricity markets focused on market splitting approaches that create multiple price areas within a national system and implies "locational" energy prices. This could be implemented as early as 2015"*

6.2. Preventing Distortions to Cross-Border Trade

As we demonstrate using the worked example in Section 3.3, the WACM 2 charging model, and the other variants that link TNUoS charges to historic or outturn load factor, will increase the marginal costs that generators incur (or avoid) when they are dispatched (or reduce output). As we discuss, this might distort patterns of dispatch, as generators in high TNUoS zones will be pushed further down the merit order than those in low TNUoS zones. Furthermore, it will also distort trade with neighbouring markets, as the transmission infrastructure charges paid by generators in other NW European jurisdictions are not linked to energy production.

Through CMP201, Ofgem is now considering removing the BSUoS charge levied on generators to better align the GB market with other EU markets, where, according to National Grid, "*generation is not typically subject to such charges*".[85] National Grid also states that the proposed change will remove the potential for BSUoS to distort cross-border trade.[86] Pending the outcome of Ofgem's consultation on CMP201,[87] it would seem inconsistent to remove energy-based generation BSUoS charges on the basis that they are distortionary, while at the same time imposing new TNUoS charges that create the same problem.

6.3. Consistency with Ofgem's ITPR Project

Ofgem's Integrated Transmission Planning and Regulation (ITPR) project reviews the GB electricity transmission arrangements for system planning and delivery that currently apply to onshore, offshore and interconnector assets. The focus is on ensuring the efficient, coordinated and economic development of the overall network over the longer-term. Hence, Project TransmiT represents an important opportunity to facilitate, through sending cost-reflective network pricing signals to all network users, development of a framework for effective coordination of investment across the three transmission regimes (onshore, offshore and cross-border), facilitate the development of multi-purpose projects and deliver efficient transmission investment.

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85 According to National Grid, the presence of BSUoS is a disadvantage to GB generators when competing with EU wholesale generators. See: National Grid, *CMP201 Removal of BSUoS Charges from Generation Volume 1*, para 2.3

86 National Grid, *CMP201 Removal of BSUoS Charges from Generation Volume 1*, para 1.1

87 Ofgem's website (visited on 27 August 2013) notes that it expects the consultation on CMP201 to open in September 2013. URL: https://www.ofgem.gov.uk/publications-and-updates/impact-assessment-consultation-cmp201-proposal-remove-bsuos-charges-generators

Given the size and the level of uncertainty surrounding the British transmission investment programme, it important that efficient market arrangements ensure investment is delivered in a timely and efficient manner.[88] In this context, efficient transmission pricing is important for driving efficient siting decisions of new generating plant and for incentivising network users to actively engage in the transmission planning process by minimising the costs they incur to access the market, and thus ensuring the efficiency of the overall transmission investment process.

Cost reflective location specific transmission charges will, through active engagement of network users, provide the basis for the development of alternatives to network reinforcement through various operational measures and corrective control techniques. This would enhance the utilisation of existing primary network assets and hence ensure the efficiency of unprecedented transmission network investment that GB is facing. Furthermore, active user engagement, facilitated through cost reflective location specific network pricing, would also alleviate the need for the regulator to act as the sole buyer of network services on behalf of all users, so as to ensure that the planning and delivery of network investment is as efficient as possible.

In this context, Project TransmiT represents a key opportunity for facilitating efficient investment in future transmission infrastructure. However, our analysis shows that the proposed WACM 2 charging methodology does not materially improve the cost reflectivity of the current TNUoS methodology. This undermines the objectives of achieving efficiency in transmission network investment and thus contradicts Ofgem's ITPR project objectives.

6.4. Conclusions

Ofgem's Impact Assessment fails to consider interactions with the need to introduce the EU Target Model, which may introduce zonal energy pricing in some form that would reflect constraint costs through regional variation in the wholesale energy price. The current TNUoS charging model, or the proposed WACM 2 alternative, might therefore require revision as the British market is brought into line with other neighbouring markets, which would create additional instability in TNUoS and leave insufficient time for any supposed efficiency benefits associated with WACM 2 to be realised. The WACM 2 model, by linking TNUoS charges to dispatch, would also distort dispatch and trade with neighbouring markets.

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[88] Imperial College and Cambridge University: "Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery", June 2013, https://www.ofgem.gov.uk/ofgem-publications/52727/imperialcambridgeitprreport.pdf

7. Conclusion

Ofgem's case for implementing the WACM 2 TNUoS charging model hinges on the argument that it is more cost reflective than the status quo and the alternatives under consideration. We have identified several flaws in the evidence Ofgem uses to reach this conclusion, including significant shortcomings in the quantitative modelling it cites, and our own analysis suggests that the WACM 2 methodology results in charges that are no more cost reflective than the status quo.

At the same time, Ofgem's decision ignores numerous problems associated with Ofgem's minded to decision to introduce the WACM 2 charging model. In particular, Ofgem has failed to rigorously account for the costs of distributional effects, it has overlooked the distortions to dispatch the WACM 2 model will cause, and does not account for the possibility that further market reform to implement the EU Target Model will necessitate further changes to the TNUoS methodology in the coming years.

Finally, and leaving aside these significant problems with the decision to implement the WACM 2 charging model, Ofgem's decision to implement the new arrangements from 1 April 2014 takes no account of this time it takes to respond to changes in TNUoS, and would exacerbate the distributional effects associated with the proposed reforms.

Appendix A. Other Models Ofgem Considered

As described in Section 1.1, the CUSC Panel voted in favour of a number of alternative charging models to the “status quo”. This appendix provides a summary of these alternative models.

A.1. Reflecting Dual Drivers of Investment

The various charging models put forward by the Workgroup members draw on the dual backgrounds for transmission planning included in the SQSS. Most charging models (except the “Diversity 3” approach, see below) require runs of two load flow models that implement the “demand security” and “economic” criteria in the SQSS. The modelled flows from both runs are compared for every circuit in the system and the more conservative flow criterion applies. That is, circuits with the highest flows in the Economy Background are flagged as being required to fulfil the “economic criterion,” and all others are flagged as being required to meet the “demand security criterion.”

Under each generation background, an incremental MW of generation is then added sequentially to every node on the system[89] to identify the additional load flows over the network measured in MWkm. This calculation is performed separately for the circuits, to which the “demand security” and “economic” criteria apply, i.e., where the relevant criterion is more onerous. The results are averaged across all nodes within each zone on the network, weighted in proportion to assumed generation output across the nodes.

For each zone, the final step is to multiply the incremental network flows (in MWkm) by an “expansion constant” (in £/MWkm) to denote charges appropriately on a £/kW basis.[90] Depending on whether the Security Background or the Economy Background applies, this adjustment is made to the “peak security” or “year-round” charge, respectively.

A.2. Accounting for “Diversity”

The charging models differ according to how they use these charges based on the two runs of the load flow model, and in particular, how they scale generators’ liability to pay the “year-round” charge depending on the mix of “low carbon” and “carbon” generation capacity connected to a transmission circuit. Table A.1 below reports the Workgroup’s proposed low carbon/carbon classifications, which National Grid describes as “*a simplified way of categorising plant by likely bid price characteristics*.”

89 NGET subtracts a corresponding MW of generation from a reference node to equate generation and load.

90 In practice, this figure would also be multiplied by a security factor, and scaled according to the “G:D split”, which determines the share of network costs recovered from generation and load.

Table A.1
Classification Used for Carbon vs Low Carbon

Carbon	Low Carbon
Coal	Wind
Gas	Hydro (excl. pumped storage)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

Source: FMR, Table 13, Page 41

National Grid has used the above classifications to calculate the Diversity TNUoS charges in its impact assessment modelling.

- Diversity 1, which is included in the WACM 2 variant that Ofgem is minded to adopt, splits the "year round" charge into two components that aim to reflect the costs of "shared" and "non-shared" assets:
  - Where a transmission boundary has 100 per cent of "low carbon" capacity behind it, this circuit is not considered under the charging model to be "shared" between "low carbon" and other types of generation. Assuming that this circuit is allocated to the Economy Background, generators' "year round" charges would include the costs of that circuit through a £/kW charge;
  - Between 100 per cent and 50 per cent "low carbon" generation the proportion of costs treated as "shared" decreases linearly, so that a decreasing share of the "year round" £/kW charge allocated according to the Economy Background is scaled by generators' ALFs.
  - Where a transmission boundary has less than 50 per cent of "low carbon" capacity behind it, this asset is considered under the charging model to be entirely "shared" between "low carbon" and other types of generation. Assuming that this circuit is allocated to the Economy Background, generators' "year round" charges would include the costs of that circuit through a £/kW charge, but fully scaled to generators' ALF;
- Diversity 2 is similar to Diversity 1, but uses a different approach to define whether transmission circuits are "shared" or "non-shared". It assumes that, where a transmission boundary has 50 per cent of "low carbon" capacity behind it, the extent of sharing is highest, and costs are scaled by generators' ALFs, with half allocated to a £/kW charge. As the share of "low carbon" generation increases or decreases, the degree of assumed sharing falls linearly, so that where the share of "low carbon" generation behind a boundary falls to 0 per cent or 100 per cent, the level of sharing approaches zero.
- Diversity 3 differs from the other two methods in that it only uses a single "year round" background and does not consider "peak security" charges at all. Another key difference is that ALF is not factored into the calculation of the "Diversity 3" tariff. Instead, the

"year round" charge is scaled by a "zonal sharing factor" (ZSF) which is found by dividing zonal shared incremental kilometres by total incremental kilometres. The proportion of shared incremental km is determined using the same rule as "Diversity 2", described above.

A.3. The Use of Load Factor to Scale "Year Round" Charges

The original, Diversity 1 and Diversity 2 methodologies all use ALF as a measure of a plant's incremental cost under "year round" conditions. In the original "improved ICRP", ALF enters the tariff calculation as a scaling factor, applied to the "year round" charge. In the Diversity 1 and 2 methodologies, which break the "year round" charge into *shared* and *not shared* components, the ALF only scales the *shared component*. The industry workgroup has proposed two possible methods for calculating ALF:

- **Historical five year annual load factor:** the average load factor achieved over the last five years, excluding the highest and lowest year from the calculation. For newer generators, the ALF would be a straight average of the load factors achieved over the last 3 years. Where 3 years of data is not available, standardised technology-specific load factors would be used.
- **"year round" forward looking hybrid:** prior to the start of each charging year, plants have the option to accept the above five year average or submit their own forecast annual load factor. User submitted forecasts would be subject to ex-post reconciliation, with some form of penalty applied to underestimates to incentivise accurate forecasting. The exact form of the penalty has not yet been specified.

A.4. Treatment of Island Links and HVDC Bootstraps

All of the CMP213 options account for the development of High Voltage Direct Current (HVDC) "bootstrap" circuits, that will run parallel to the AC transmission network. The original "improved ICRP" and all of the WACMs treat HVDC links as 'pseudo-AC' for the purpose of calculating incremental flows, and calculate unique expansion factors for each individual HVDC circuit, including cable and converter station costs. However, the CMP213 options vary in the proportion of the costs of HVDC converter stations which are removed from the wider locational tariff calculation and socialised through the residual element of the tariff. The options for the treatment of conversion station costs, seen in the various WACMs considered by Ofgem are:

- Remove 50 per cent of converter costs (based on the fact that HVDC have a number of elements in common with AC substations, the costs of which are socialised);
- Remove 60 per cent of converter costs (based on the above 50 per cent + 10 per cent for similarities to Quadrature Boosters (QBs), the costs of which are socialised);
- The CMP213 options also account for the potential development of island links using above approach but with a 70 per cent cost removal option in place of the 60 per cent option (based on Voltage Source Converter (VSC) costs as opposed to QB costs); and
- The original "improved ICRP" and WACM 2 both include the full cost of converter stations in the calculation of the expansion factor for HVDC bootstraps and island links – that is, none of the costs are socialised.

A.5. Summary

Table A.2 summarises the charging methodologies underpinning the Working Group Alternative CUSC Modifications (WACMs) that were submitted to Ofgem for consideration. As noted in Chapter 1, Ofgem is minded to implement "WACM 2", which adopts the Diversity 1 method with the following additional features:

- Load factors are calculated as a five-year historical average with highest and lowest value removed
- None of the HVDC bootstrap costs are socialised.
- None of the island link costs are socialised.

Table A.3 summarises the key features of all eight WACMs (denoted *2, 19, 21, 23, 26, 28, 30* and *33*) that Ofgem considered in its Impact Assessment.

Table A.2
Summary of Alternative Charging Methodologies

	Charging Methodology				
Characteristic	**Status Quo**	**Original "improved ICRP"**	**Diversity 1**	**Diversity 2**	**Diversity 3**
Wider Locational Tariff Components	Single *Peak Security* component	Two components: *Peak Security* and *Year Round*	3 components: *Peak Security* , *Year Round* (shared) and *Year Round* (not shared)	3 components: *Peak Security* , *Year Round* (shared) and *Year Round* (not shared)	Single *Year Round* component
Diversity Approach	n.a.	n.a.	Allocates *Year Round* incremental km to shared and not shared components based on LC conc. (see below)	Allocates *Year Round* incremental km to shared and not shared components based on LC conc. (see below)	*Year Round* scaled by *zonal sharing factor,* determined by LC conc. (see below)
Diversity Assumptions (LC - Total Quantity of low carbon TEC behind boundary length)	n.a.	n.a.	**LC/TEC <50%**: 100% Shared **LC/TEC >50%:** Sharing decreases linearly from 100% to 0%	**0%<LC/TEC <50% :** Sharing increase linearly from 0% to 50% **50%<LC/TEC<100%:** Sharing decreases linearly from 50% to 0%	As for Diversity 2
Load Factor Adjustment (LFA)	No LFA	ALF x Year Round	ALF x Year Round (shared)	ALF x Year Round (shared)	No LFA

Table A.3
Working Group Alternative CUSC Modifications (WACMs)

	2	19	21	23	26	28	30	33
NGET Original								
Sufficient diversity assumed to exist throughout GB			X			X		
Diversity method 1	X	X		X	X		X	X
Diversity method 2								
Diversity method 3								
Load Factor Assumptions								
Historical 5 year Annual Load Factor	X		X	X		X	X	
YR Forward looking hybrid		X			X			X
HVDC - Bootstraps								
Remove generic proportion of costs (60%)		X						
Remove generic proportion of costs (50%)						X	X	X
Remove generic proportion of costs (x%)			X	X	X			
Remove no cost	X							
Islands								
Remove generic proportion of costs (70%)								
Remove generic proportion of costs (50%)		X				X	X	X
Remove specific proportion of costs			X	X	X			
Remove no cost	X							

Source: Ofgem

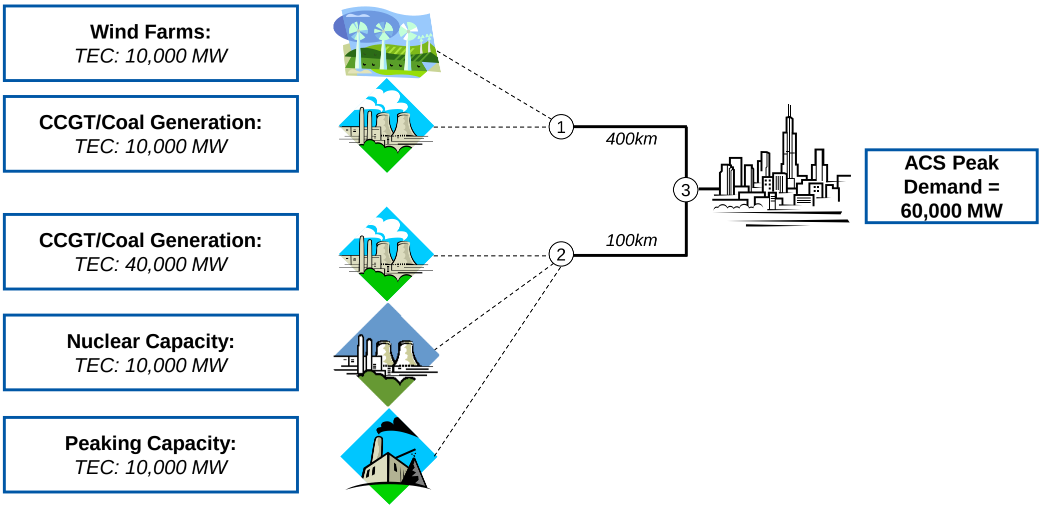
Appendix B. Consistency of WACM 2 with the SQSS Criteria

B.1. A Schematic Transmission System

We use the schematic transmission system presented in the figures below to illustrate the investment costs that TOs incur to accommodate different types of generation on their networks in order to comply with the new SQSS.

Figure B.1 shows a transmission system containing three nodes. At the first node, 10,000MW of wind generation capacity, and 10,000MW of coal/CCGT capacity connects to the system. At a second node 40,000MWof coal/CCGT capacity connects, alongside 10,000MW of nuclear and 10,000MW of peaking plant. Demand is located at the third node, with ACS peak assumed to be 60,000MW. Node (1) is located 400 kilometres from demand, and node (2) is located 100 kilometres from demand.

Figure B.1
Schematic Transmission System



Source: NERA analysis and illustrative assumptions.

In the "demand security criterion" specified in the SQSS, as Figure B.2 shows, the wind capacity at node (1) is assumed not to run at all, because it represents intermittent generation capacity. All other plants on the system are "variably scaled" to meet demand. Under this pattern of dispatch, flows across the transmission line (1)-(3) would be 8,571MW, and flows across the line (2)-(3) would be 51,429MW.[91]

In the "economic criterion" specified in the SQSS, as Figure B.3 shows, the wind farms run at 70 per cent of capacity, the nuclear plants run at 85 per cent of capacity, and the peaking

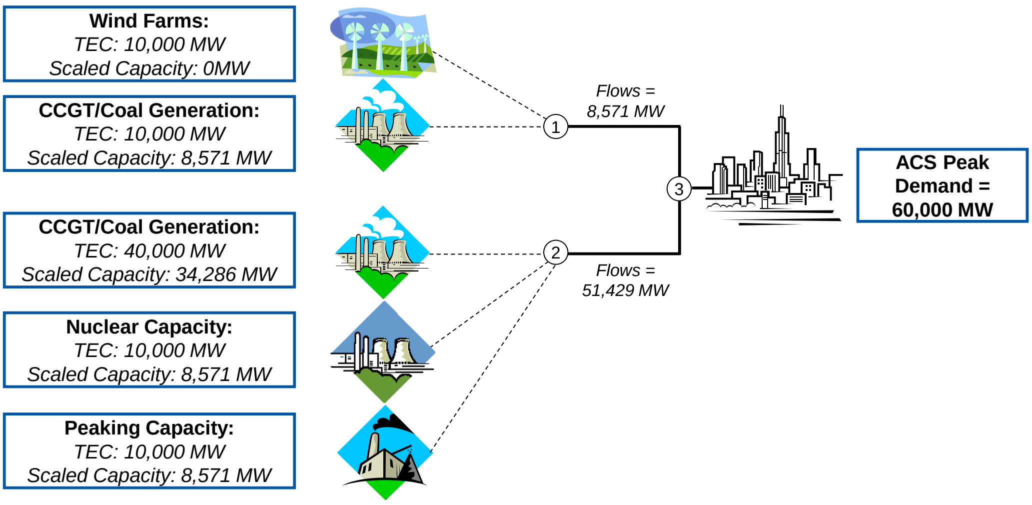
[91] Flows on each transmission line are computed as aggregate of the plants' scaled capacity on that line, where the scaled capacity equals the plant's non-intermittent generation capacity as a fraction of total non-intermittent generation capacity times the ACS peak demand. For transmission line (1)-(3) this amounts to the CCGT/Coal scaled capacity of (10,000MW/70,000MW)×60,000MW = 8,571MW. Transmission line (2)-(3) flow is the aggregate of the scaled nuclear and peaking capacity, which are computed analogously to CCGT/Coal.

plants do not run at all. The coal and CCGT plants on the system are "variably scaled" to meet demand. Under this assumed pattern of dispatch, flows across the transmission line (1)-(3) would be 15,900MW, and flows across the line (2)-(3) would be 44,100MW.

Comparing the two scenarios shows that flows are highest on the (1)-(3) line according to the "economic criterion", whereas flows are highest on the (2)-(3) line according to the "demand security criterion." Hence, under the WACM 2 model, the costs of the (1)-(3) line would be allocated to the "year round" charge, and the costs of the (2)-(3) line would be allocated to the "peak security" charge.

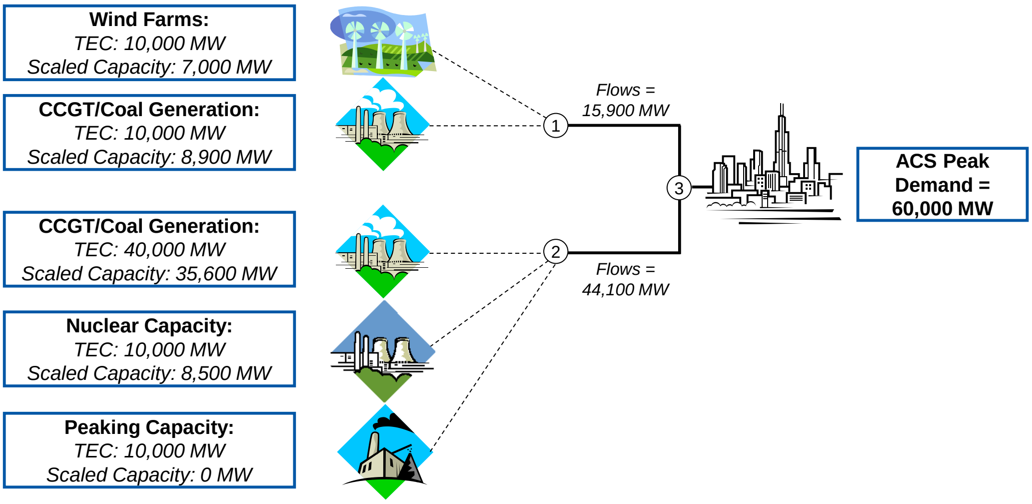
Moreover, the example shows that, if the TO builds precisely enough capacity to comply with the SQSS planning criteria, it would need to provide 15,900MW of transmission capacity along route (1)-(3), and 51,429MW of transmission capacity along route (2)-(3). Assuming the investment cost of providing network capacity is £10/MWkm, it follows that the cost of providing an incremental MW of transmission capacity along the (1)-(3) route is £4/kW, and the cost of providing an incremental MW of transmission capacity along the (2)-(3) route is £1/kW. The difference between these reinforcement costs is due to the assumed distances from nodes (1) and (2) to load, as shown in Figure B.1. These assumptions will be important for further analysis below.

Figure B.2:
Peak Security Criterion Background: Illustrative Load Flow



Source: NERA analysis and illustrative assumptions.

Figure B.3:
Economic Criterion Background: Illustrative Load Flow



Source: NERA analysis and illustrative assumptions.

B.2. The Impact of Load Factor on Investment Costs

To illustrate the costs the TO incurs to connect generators in this schematic transmission system, suppose that a new 1MW wind turbine connects at node (1). This change in generation capacity would not affect required transmission capacity under the "demand security criterion", as wind capacity is assumed not to run in the Security Background. However, it will affect patterns of requirement according to the "economic criterion". In this case, the "scaled" output from wind will rise by 0.7 MW, as the incremental MW of capacity is assumed to run at 70 per cent. Assuming demand does not change, the output from all the "variably scaled" generators will fall slightly to compensate. The net effect is that flows on the (1)-(3) transmission line rise by 0.56MW, as wind output is 0.7MW higher, but output from the conventional generators at node (1) falls by 0.14MW to ensure that supply matches ACS peak demand. Hence, to accommodate an incremental MW of wind at node (1), the TO incurs a cost of £2.24/kW of TEC (= 0.56 x £4/kW).[92]

Similarly, an incremental MW of CCGT or coal generation capacity at node (1) increases "variably scaled" generation according to the "economic criterion" and increases the amount of capacity required on the (1)-(3) route by 0.71MW. This extra capacity requirement imposes a cost of £2.848/kW. No extra capacity is required on the line (2)-(3).[93]

As noted above, costs of the line (2)-(3) are allocated to the "peak security" charge. Hence, an incremental MW of generation capacity at node (2) has no effect on the costs of complying with the "economic criterion," i.e., the "year round" charge. An incremental MW

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92 We note that aggregate flows in this example are of course unchanged, as total scaled capacity equates with ACS peak demand. The higher requirement for line (1)-(3) is balanced by the corresponding excess capacity on line (2)-(3).

93 In fact, line (2)-(3) has excess capacity equal to the extra requirement on line (1)-(3) for the analogous reason as given in supra note 92.

of any generation capacity at node (2), which is all "variably scaled" according to the "demand security criterion," increases flows from (2) to (3) by 0.12MW, and therefore imposes a cost of £0.12/kW on the TO in order to comply with the SQSS (= 0.12 x £1/kW).

Table B.1
The Incremental Cost of 1MW of TEC

Node	Technology	Incremental Reinforcement Triggered (MW)			Reinforcement Cost (£/MW/km)	Distance (km)	Incremental Cost (£/kW of TEC)		
		Peak	*Economic*	*Total*			*Peak*	*Economic*	*Total*
(1)	Wind Farm	0.00	0.56	0.56	10.00	400	0.00	2.24	2.24
(1)	Conventional	0.00	0.71	0.71	10.00	400	0.00	2.85	2.85
(2)	Conventional	0.12	0.00	0.12	10.00	100	0.12	0.00	0.12
(2)	Peaking	0.12	0.00	0.12	10.00	100	0.12	0.00	0.12
(2)	Nuclear	0.12	0.00	0.12	10.00	100	0.12	0.00	0.12

Source: NERA analysis and illustrative assumptions.

This analysis illustrates that the incremental investment cost of reinforcement to accommodate an incremental MW of TEC while complying with the economic criterion in the SQSS, as summarised in Table B.1, depends on the scaling factors in the SQSS, as well as the type of installed capacity and its location. The actual energy produced by any generator over the year has no influence on the costs of complying with the SQSS economic and peak security criteria. This feature is as we would expect, given the economic and peak security criteria trigger obligations for TOs to make investments and incur investment costs when generators connect, independent of generators' actual running once connected. The fact that the WACM 2 model calculates charges as a function of load factor therefore demonstrates that this charging model will not reflect the costs that a generator's presence imposes on the TOs to comply with the economic and peak security criteria in the SQSS.

B.3. Comparison of Reinforcement Costs to WACM 2 Tariffs

Table B.2 shows a derivation of the TNUoS charges that the five groups of generators would face under WACM 2. In this example, we make a series of simplifying assumptions. We assume that the G:D split is 100:0, that the security factor is 1.0, and we assume an expansion constant (i.e. the incremental cost of adding transmission capacity) of £10/MWkm. We also use node (3) as a "reference node", where we add a MW of demand when examining the impact of increasing generation by a MW at nodes (1) and (2) in order to maintain a balanced system.

Adding a MW of generation at node (1) and a MW of demand at node (3) increases flows across the line (1)-(3) by 400MWkm in both backgrounds. In other words, there are 400 "incremental km" associated with the (1) – (3) boundary length in both backgrounds. As described in Appendix A, the Diversity 1method, which underpins WACM 2, allocates a certain proportion of "year round" incremental km to a *shared* charge component and the rest to a *not shared* component, depending on the concentration of low carbon generation behind each boundary length according to the following rules

- If the concentration of low carbon capacity is less than 50 per cent, 100 per cent of the incremental km are allocated to the *shared* component; and

- As the concentration of low carbon capacity rises above 50 per cent, the shared portion falls linearly from 100 per cent to zero per cent.

Therefore, since generation at node (1) is split 50:50 between low carbon and conventional capacity, the “year round” charge is 100per cent shared and is set at £4/kW (=400km*£10/MW/km/1000). For each generator the “year round” *shared* charge is multiplied by their annual load factor. Hence, the wind generators pay £1/kW (= £4/kW × 25 per cent) and the conventional generators pay £2.80/kW (= £4/kW × 70 per cent; note, this is identical to the “year round” charge generators would face under WACM 2). The “peak security” charge for generators at node (1) would be £0/kW, as only line (2)-(3) flows are assumed to follow the “demand security criterion”, and flows on this line do not change by adding a MW of generation to node (1) and a unit of demand to node (3).

Table B.2
Derivation of WACM 2 TNUoS Charges

Node	Technology	Load Factor	Sharing Factor	TEC (MW)	Incremental km			WACM 2 TNUoS Charges with Load Factor Scaling (£/kW of TEC)			
					Peak	*Year Round (shared)*	*Year Round (not shared)*	*Peak*	*Year Round (shared)*	*Year Round (not shared)*	*Total*
(1)	Wind Farm	25%	100%	10,000	0.00	400.00	0.00	0.00	1.00	0.00	1.00
(1)	Conventional	70%	100%	10,000	0.00	400.00	0.00	0.00	2.80	0.00	2.80
(2)	Conventional	70%	100%	40,000	100.00	0.00	0.00	1.00	0.00	0.00	1.00
(2)	Peaking	5%	100%	10,000	100.00	0.00	0.00	1.00	0.00	0.00	1.00
(2)	Nuclear	85%	100%	10,000	100.00	0.00	0.00	1.00	0.00	0.00	1.00

Source: NERA analysis and illustrative assumptions.

Table B.3 compares these illustrative Diversity 1 tariffs to the incremental cost imposed by each generator when they obtain an incremental MW of TEC, which arises from the TO’s need to comply with the “demand security” and “economic” criteria in the SQSS, as shown in Table B.1.

Table B.3
Incremental Reinforcement Costs vs. WACM 2 TNUoS Charges

Node	Technology	Incremental Cost (£/kW of TEC)	WACM 2 TNUoS Charges (£/kW of TEC)	Difference (£/kW of TEC)
		Total	*Total*	*Total*
(1)	Wind Farm	2.24	1.00	-1.24
(1)	Conventional	2.85	2.80	-0.05
(2)	Conventional	0.12	1.00	0.88
(2)	Peaking	0.12	1.00	0.88
(2)	Nuclear	0.12	1.00	0.88

Source: NERA analysis and illustrative assumptions.

Table B.3 shows that wind generators at node (1) only face a TNUoS charge of £1/kW, as compared to the incremental cost of accommodating an additional MW of wind generation capacity at node (1) of £2.24/kW. This difference arises because the incremental cost of reinforcement on line (1)-(3) of £4/kW is multiplied by a 25% load factor to calculate the "year round" charge, and not by the 56% factor that actually drives the incremental reinforcement cost on the affected transmission line.

In fact, if we had assumed that the wind generator runs at 30% instead of 25% (see Table B.2), it would have made no difference to the investment cost incurred to comply with the economic criterion in the SQSS, but its TNUoS charge would have increased.

The CCGT/coal plants located at node (1) pay a TNUoS charge under WACM 2 that is close to the costs they impose on the TO in order to comply with the SQSS. This arises because its assumed load factor (70%) approximately reflects the 71% factor that actually drives the incremental reinforcement cost on the affected line (1)-(3), although as noted above, this similarity arises coincidentally, because the load factor does not cause TOs to incur investment costs. For example, if we had assumed a 50% load factor, the conventional generator would pay a charge below the costs it imposes on the TO, and if we had assumed a 90% load factor, it would pay more than the costs it imposes.

All technologies at node (2) pay a charge higher than the costs of accommodating an incremental MW of generation in the peak security and economic criteria in the SQSS, because the "peak security" charge does not reflect the scaling back of generation capacity according to the "demand security criterion" under the SQSS after an incremental MW of TEC connects to the system.

B.4. The Effects of Diversity Adjustments

One of the main arguments Ofgem uses to justify implementation of the WACM 2 methodology is that the underlying Diversity 1 methodology "*recognises that intermittent plant in low carbon dominated zones tend to drive more transmission investment costs*". In this section we explore how the relationship between SQSS-triggered incremental reinforcement costs and TNUoS charges varies with the concentration of low carbon generation under Diversity 1. To do this, we use the above schematic transmission network, but with scenarios of 40 per cent (8,000 MW), 60 per cent (12,000MW) and 100 per cent (20,000) low carbon generation at node (1).

As the worked example in Section B.3 shows, the calculation of the "year round" tariff is relatively straightforward when the proportion of the low carbon generation behind the relevant boundary lengths is less than 50 per cent, as the charge comprises a *shared* component only, which is fully scaled by plant load factor. This is equivalent to the original "improved ICRP" approach.

To see how the "year round" tariff calculation works when the low carbon concentration is greater than 50 per cent, consider the 60 per cent scenario. As for the 50% scenario described above, there are 400 "incremental km" associated with the (1) – (3) boundary length in both backgrounds. Since the concentration of low carbon generation behind (1) – (3) is 60 per cent, 320 incremental km (400km × (1-0.6)/0.5) will be allocated to the "year round" "shared" component, with the remainder being allocated to the "not shared" component. This gives "shared" and "not shared" "year round" charges of £3.20/kW (320km × £10/MW/km/1000) and £0.8/kW (80km × £10/MW/km/1000) respectively. Only the "shared" charge is subject to load factor scaling. Hence, the wind generators pay £1.60/kW (= £3.2/kW × 25 per cent +

£0.8/kW) and the conventional generators pay £3.04/kW (= £3.2/kw × 70 per cent + £0.8/kW). The derivation of these charges is summarised in Table B.4 below.

Table B.4
Derivation of WACM 2 TNUoS Charge for 60% Low-Carbon Scenario

Node	Technology	Load Factor	Sharing Factor	TEC (MW)	Incremental km			WACM 2 TNUoS Charges with Load Factor Scaling (£/kW of TEC)			
					Peak	*Year Round (shared)*	*Year Round (not shared)*	*Peak*	*Year Round (shared)*	*Year Round (not shared)*	*Total*
(1)	Wind Farm	25%	80%	12,000	0.00	320.00	80.00	0.00	0.80	0.80	1.60
(1)	Conventional	70%	80%	8,000	0.00	320.00	80.00	0.00	2.24	0.80	3.04
(2)	Conventional	70%	100%	40,000	100.00	0.00	0.00	1.00	0.00	0.00	1.00
(2)	Peaking	5%	100%	10,000	100.00	0.00	0.00	1.00	0.00	0.00	1.00
(2)	Nuclear	85%	100%	10,000	100.00	0.00	0.00	1.00	0.00	0.00	1.00

Source: NERA analysis and illustrative assumptions

Table B.5, Table B.6 and Table B.7 compare WACM 2 tariffs to the incremental costs for the above schematic transmission network, but with 40 per cent (8,000 MW), 60 per cent (12,000MW) and 100 per cent (20,000) low carbon generation at node (1).

Table B.5
Incremental Reinforcement Costs vs. WACM 2 TNUoS Charges (40% Low Carbon Concentration)

Node	Technology	Incremental Cost (£/kW of TEC)	WACM 2 TNUoS Charges (£/kW of TEC)	Difference (£/kW of TEC)
		Total	*Total*	*Total*
(1)	Wind Farm	2.15	1.00	-1.15
(1)	Conventional	2.72	2.80	0.08
(2)	Conventional	0.14	1.00	0.86
(2)	Peaking	0.14	1.00	0.86
(2)	Nuclear	0.14	1.00	0.86

Source: NERA analysis and illustrative assumptions

Table B.6
Incremental Reinforcement Costs vs. WACM 2 TNUoS Charges (60% Low Carbon Concentration)

Node	Technology	Incremental Cost (£/kW of TEC)	WACM 2 TNUoS Charges (£/kW of TEC)	Difference (£/kW of TEC)
		Total	*Total*	*Total*
(1)	Wind Farm	2.33	1.60	-0.73
(1)	Conventional	2.99	3.04	0.05
(2)	Conventional	0.10	1.00	0.90
(2)	Peaking	0.10	1.00	0.90
(2)	Nuclear	0.10	1.00	0.90

Source: NERA analysis and illustrative assumptions

Table B.7
Incremental Reinforcement Costs vs. WACM 2 TNUoS Charges (100% Low Carbon Concentration)

Node	Technology	Incremental Cost (£/kW of TEC)	WACM 2 TNUoS Charges (£/kW of TEC)	Difference (£/kW of TEC)
		Total	*Total*	*Total*
(1)	Wind Farm	2.80	4.00	1.20
(1)	Conventional	3.75	4.00	0.25
(2)	Conventional	0.00	1.00	1.00
(2)	Peaking	0.00	1.00	1.00
(2)	Nuclear	0.00	1.00	1.00

Source: NERA analysis and illustrative assumptions

The above tables, along with Table B.3, suggest that reinforcement costs incurred to comply with the SQSS economic and peak security criteria differ systematically from WACM 2 tariffs across the full range of generation mixes. For example, when the concentration of low carbon generation is low (i.e. less than 50 per cent), the TNUoS tariff for wind significantly under-estimates the cost it imposes on the TOs to comply with the two planning criteria. This is because the "year round" charge is 100 per cent shared and is therefore fully scaled by the 25 per cent load factor. As the low carbon concentration rises above 50 per cent, the TNUoS charge increases relative to reinforcement costs as the shared portion – that is, the portion which is scaled by load factor – decreases. When the generation is 100 per cent low carbon, the "year round" charge is 100 per cent *not shared* and wind generators must pay the full £4/kW. This is equivalent to assuming that an expanding wind capacity of 1MW is accompanied by 1MW expansion in network capacity. This is an overestimate, relative to the investment implied by the SQSS economic and peak security criteria, which scales back wind generation to 70 per cent under "year round" conditions.

B.5. Summary

While we recognise that the above analysis uses a simplistic representation of the transmission system and more work would be required to assess the cost reflectivity of the WACM 2 model, including empirical analysis using data from the actual transmission system, these worked examples enable us to draw some general conclusions regarding the WACM 2 model as it currently stands.

The analysis shows that there exist plausible situations in which the "year-round" and "peak security" charges under WACM 2 differ materially from the reinforcement costs imposed on the TO by their obligation to comply with the SQSS "economic" and "peak security" planning criteria. To the extent that these planning criteria drive the investment requirements imposed on TOs following the implementation of GSR009, this analysis suggests that the proposed charging model is not cost reflective.

Of course, as we note in Section 2.2, investments by TOs might be triggered either by the need to comply with these criteria, or the additional obligation to provide more capacity is this is justified by a full CBA. Hence, the proposed charging model could still be considered cost reflective if it reflected the incremental costs of providing the capacity prescribed by such an approach. However, as described in the body of this report:

- The economic criterion is designed to prescribe slightly more investment than would be optimal under a full CBA, so in practice, it is likely to be the binding driver of investment requirements;
- The evidence prepared by and presented to Ofgem that the WACM 2 charging model does reflect the costs of providing the capacity prescribed by a full CBA is incomplete and flawed; and
- Our own analysis suggests that the WACM 2 tariffs are no more cost reflective than the status quo, when we compare modelled tariffs to the incremental costs emerging from the DTIM transmission planning model.

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