Project TransmiT: Critical Review of Ofgem's April 2014 Further Consultation

Prepared for RWE npower

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NERA Project Team

Sean Gammons
Richard Druce
Peter Davies
Matthew Mair

Imperial College Project Team

Prof. Goran Strbac
Dr Christos Vasilakos
Dr Rodrigo Moreno
Dr Dimitrios Papadaskalopoulos
Dr Danny Pudjianto

NERA Economic Consulting
15 Stratford Place
London W1C 1BE
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com

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Executive Summary

On 25 April 2014, Ofgem issued, as part of the Project TransmiT process, a document consulting on proposed changes to the British electricity transmission charging methodology. RWE npower has commissioned NERA and Imperial College London to review this document.

Ofgem's latest consultation paper reviews the evidence Ofgem has received in response to its August 2013 Impact Assessment that led to its "minded to" decision to implement a new charging methodology, known as "WACM 2", and presents new evidence that compares WACM 2 with the existing "status quo" charging methodology. The consultation concludes that the evidence it reviewed has not led it to alter its minded to decision.

Ofgem's minded to decision to implement WACM 2 is based on its view that this new charging methodology would better meet the "relevant CUSC objectives" and comply with the Authority's statutory objectives. In particular, Ofgem believes that the WACM 2 charging model is more cost reflective. As well as being a CUSC objective in its own right, Ofgem believes this feature of WACM2 will promote efficiency and benefit consumers. However, Ofgem's conclusion that WACM 2 better meets these criteria and objectives is flawed for the following reasons:

- There is no basis for Ofgem's assertion that the WACM 2 methodology is cost reflective and consistent with the new SQSS, which determines the transmission investment costs TOs incur to accommodate generators. Our own analysis suggests WACM 2 sends less efficient locational signals than the status quo methodology:
  - While the SQSS and the WACM 2 charging methodology do share some common features, such as the "dual background", the similarities are partial and superficial;
  - Ofgem has asserted that WACM 2 reflects the SQSS, without any attempt to justify that the structure of the formulae, parameters and procedure used to set WACM 2 tariffs actually result in tariffs that reflect the costs TOs incur to accommodate incremental generation capacity (in compliance with the SQSS) any more closely than the status quo;
  - Ofgem has done no analysis to test whether the tariffs resulting from the WACM 2 methodology reflect the cost of transmission that TOs incur to accommodate incremental generation capacity. Its rationale for not doing so - that such modelling requires subjective assumptions - is inconsistent with its decision to conduct the welfare modelling exercise during the Project TransmiT process, as that too requires what might be called subjective assumptions;
  - Our own comparison of WACM 2 tariffs to the marginal costs of transmission that TOs incur to accommodate generators suggests WACM 2 is less cost reflective than status quo. Specifically, WACM 2 sends less efficient locational signals to wind farms than the status quo; and
  - Ofgem's critique of this analysis is based on the unsubstantiated assertion that it may be possible to reinforce the Scotland-England transmission boundaries without the use of HVDC technology (or some alternative that is no less expensive). Our research has not identified any published source that supports Ofgem's assertion;

- Ofgem believes that the WACM 2 charging model would benefit current and future consumers. However, the evidence it has reviewed does not support this position:
  - Modelling work Ofgem commissioned from Baringa suggests that customer bills would increase as a result of introducing WACM 2. Our own modelling work supports this result, and the finding that WACM 2 increases wholesale energy and/or capacity prices is entirely consistent with the fundamental economic constraint that marginal new entrant power generators need to recover their costs from the market, and these costs increase under WACM 2. Ofgem's suggestion that there is uncertainty surrounding this result, or that this result depends on the precise modelling treatment of the capacity mechanism, is incorrect;
  - Ofgem notes that power sector costs fall as a result of WACM 2, but our review of the Baringa approach suggests this modelling work overstates the generation cost saving from WACM 2, and/or understates the additional transmission system costs caused by WACM 2. Hence, this result is not robust; and
  - Ofgem cites other "non-monetised" factors that it considers would result in benefits to consumers from the introduction of WACM 2:
    - In fact, some of these benefits have been "monetised" through the Baringa modelling, such as the impact of new entry into the power market to compete away higher prices and generation profits under WACM 2;
    - Other factors hinge on Ofgem's belief that WACM 2 is more cost reflective than the status quo, which is a belief not supported by evidence or cogent reasoning, as described above;
- Ofgem has failed to consider a number of other factors that would reduce the case for the introduction of WACM 2:
  - Ofgem has failed to consider the additional cost to consumers resulting from the distributional effects created by introducing WACM 2. Redistributing value around generators in the sector, without a sound justification that the decision to do so enhances efficiency, will add to perceived regulatory risk, raise financing costs to the sector, and increase customer bills;
  - WACM 2 is an energy-based charge, as increases in a generator's output today increase expected future TNUoS costs over the following 5 years. Analysis commissioned by Ofgem from Baringa shows WACM 2 does affect trade with neighbouring markets, but Ofgem has ignored this finding in reaching its minded to decision; and
  - Ofgem has ignored the possibility that the need to implement zonal wholesale power pricing to comply with the EU Target Model will affect the efficiency of any locational signals conveyed through the status quo or WACM 2 charging models, and thus undermine any supposed benefits of implementing WACM 2.

Overall, therefore, there is no basis for Ofgem's belief that the WACM 2 charging methodology better meets the relevant CUSC objectives and is in the interests of consumers. The quantitative evidence on cost reflectivity and the welfare impacts of WACM 2 suggest it would harm consumers. The qualitative benefits that Ofgem suggests would offset the quantifiable harm to consumers resulting from WACM 2 are either already covered by the quantitative modelling, or hinge on Ofgem's unsubstantiated belief that WACM 2 is more cost reflective than the status quo. Moreover, Ofgem's assessment is partial because it has omitted some of the costs of implementing WACM 2 from its consideration of the proposed reform.

1. Introduction

NERA Economic Consulting and Imperial College London have been commissioned by RWE npower to review the recent consultation document published by Ofgem relating to proposals to reform the British Transmission Network Use of System (TNUoS) Charging Methodology.[1]

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 in an attempt 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*".[2] 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*".[3]

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.[4] 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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[1] Project TransmiT: Further consultation on proposals to change the electricity transmission charging methodology, Ofgem, 25 April 2014. Unless otherwise stated, all references in this paper to Ofgem (April 2014) refer to this consultation document.

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

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

[4] 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.[5]

On 1 August 2013, Ofgem announced that it was "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).[6] 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).

1.2. Ofgem's "Minded to" Decision

Ofgem's August 2013 Impact Assessment compared 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 was that "*all of the CPM213 proposals are more cost reflective than the status quo*" and would therefore *"promote competition more effectively*".[7]

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

  Ofgem's expressed the view that alternatives featuring the proposed methodology Diversity 1 (including WACM 2) "*most appropriately reflect the TOs' investment decisions for "year round" conditions, and therefore are the most cost reflective options*".[8]

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

  Ofgem expressed the view 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*".[9]

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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5 Project TransmiT : Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology, Ofgem (137/13), 1 August 2013, para 2.12. Unless otherwise specified, all other citations of Ofgem (August 2013) in this report refer to this document.

6 Ofgem (August 2013), page 5

7 Ofgem (August 2013), para 6.9

8 Ofgem (August 2013), para 6.47

9 Ofgem (August 2013), 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*".[10]
- **Security of supply**: Ofgem did not "*consider security of supply to be materially affected by any of the CMP213 options*".[11]
- **Consumer bill impacts:** Ofgem believed that the long term benefits of the new methodology "*are likely to outweigh considerably the short term disbenefits as regards consumer bills*".[12]

Hence, as the above summary shows, Ofgem's August 2013 consultation document expressed Ofgem's belief that WACM 2 best facilitated all the "relevant objectives" for the Use of System charging methodology, as well as meeting the Authority's principal objective.

1.3. Evidence Submitted Since the "Minded to" Decision

Ofgem's April 2014 consultation re-opens the consultation on the August 2013 minded-to decision to implement WACM 2, following receipt of additional evidence on (1) the cost reflectivity of WACM 2, and (2) evidence on the impact of the proposed change on the sector and on consumers.

In October 2013, following the August 2013 Impact Assessment, NERA and Imperial prepared two reports that were submitted alongside RWE's response to Ofgem's consultation:

- In one report submitted in October 2013, NERA and Imperial reviewed the Ofgem Impact Assessment that led to Ofgem's August 2013 "minded-to" decision to implement WACM 2. The report highlights that Ofgem failed to check whether the proposed methodology reflects the costs that different generators impose on the system better than the existing methodology. Analysis presented in this report suggests that WACM 2 reflects costs less closely than the status quo methodology; and[13]
- NERA and Imperial also performed a modelling exercise to assess the economic case for introducing the WACM 2 charging model. The electricity market and transmission system modelling conducted for this assignment suggests that WACM 2 would lead to higher transmission system costs, higher generation costs, and higher consumer bills over the period to 2030. Therefore, the modelling does not support the introduction of the WACM 2 model.[14]

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[10] Ofgem (August 2013), para 6.69.

[11] Ofgem (August 2013), para 6.76

[12] Ofgem (August 2013), para 6.81

[13] Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013.

[14] Project TransmiT: Modelling the Impact of the WACM 2 Charging Model, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013.

During early 2014, Ofgem then engaged with us through bilateral discussions and a Q&A process to better understand the analysis and arguments presented in these reports. As part of this process, we prepared a third report, submitted to Ofgem in February 2014, in which we updated and expanded the analysis of whether the WACM 2 charging methodology is more cost reflective than the status quo methodology. Across a range of scenarios, the analysis showed that the WACM 2 methodology does not constitute an improvement on the existing methodology in terms of cost reflectivity.[15]

1.4. Scope of this Report

In this report, we review the new evidence and arguments presented by Ofgem in its April 2014 consultation that was prepared in response to our abovementioned reports,[16] and other responses received during the consultation process:

- In Chapter 2 we review the new evidence and arguments presented by Ofgem on the cost reflectivity of the WACM 2 charging methodology, including its response to our analysis that compares WACM 2 and status quo charges to the LRMC of transmission required to efficiently accommodate generators of different technologies at different locations on the system;
- In Chapter 3 we review the new evidence presented by Ofgem on the expected welfare effects of introducing the WACM 2 charging model, including both monetised and non-monetised factors;
- In Chapter 4 we discuss omissions from Ofgem's consultation, including the costs of introducing WACM 2 that Ofgem has failed to consider in its latest consultation; and
- Chapter 5 concludes.

For the avoidance of doubt, this report does not represent our comprehensive assessment of the Ofgem minded-to decision. It should be read alongside our earlier reports submitted in October 2013 and February 2014.

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15 Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014.

16 Ofgem (April 2014).

2. Ofgem's Assessment of New Evidence on Cost Reflectivity

2.1. Introduction

As described in the preceding chapter, Ofgem's August 2013 minded to decision to implement WACM 2 was based on an assessment of the proposed modification against the relevant CUSC objectives and the Authority's statutory duties.

With reference to the relevant CUSC objectives, Ofgem's August 2013 position was that WACM 2 is more cost reflective, which as well as being a CUSC objective in its own right, implied that WACM 2 promotes competition and reduces discrimination.[17] Ofgem's August 2013 paper also concluded that a more cost reflective charging model would be "*in the long run consumer interest*" and provided "*long term sustainability benefits*", in line with the Authority's Statutory Objectives.[18]

This chapter reviews the new evidence and arguments presented by Ofgem in its April 2014 consultation paper on the cost reflectivity of the WACM 2 charging methodology, including its response to the new evidence submitted since the August 2013 consultation. It therefore supplements our October 2013 review of the Ofgem Impact Assessment and minded-to decision, as well as the analysis contained in the follow-up report on the cost reflectivity of the WACM 2 charging methodology submitted to Ofgem in February 2014.[19]

2.2. Ofgem's Evaluation of Evidence on Cost Reflectivity

2.2.1. Conditions for efficient access pricing

As noted in our recent report on the cost reflectivity of the WACM 2 charging methodology,[20] the most efficient means of sending locational signals to generators regarding the cost they impose on the system, or value they provide to the system, is through Locational Marginal Pricing (LMP) of energy, possibly combined with a "beneficiary pays" approach to recovery of residual transmission costs that are not recovered through congestion rents, e.g. due to economies of scale in the provision of transmission. However, in the absence of LMP or other forms of zonal energy pricing, setting infrastructure charges that reflect the Long Run Marginal Cost (LRMC) that users impose on the system can send equivalent efficient signals to users.

Therefore, the most efficient and cost reflective transmission charging model would set TNUoS charges equal to the LRMC that each generator imposes on the system, subject to other relevant considerations of tariff design (e.g. simplicity and transparency). This

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17 Ofgem (April 2014), para 2.2.

18 Ofgem (April 2014), para 2.3.

19 Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014.

20 Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014, Chapter 2.

interpretation of the cost reflectivity standard is in line with the condition set out in the CUSC:[21]

> "*The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems.*"

The CUSC makes the very clear statement that TNUoS charges must reflect the "incremental" (or marginal) costs that TOs would incur to accommodate additional capacity, in order to send efficient signals to users. Similarly, as the literature review presented in our February 2014 report points out,[22] the original ICRP methodology was developed to ensure tariffs reflected the LRMC of transmission reinforcement triggered by generators in different parts of the system. Hence, the cost reflectivity of TNUoS charges should be assessed in terms of the extent to which they reflect the LRMC of transmission rather than the average cost of transmission or some other measure.

2.2.2. Ofgem has mischaracterised the NERA/ICL modelling that compares WACM 2 and status quo tariffs to LRMC

As our February 2014 report recognises, given the complexity of the calculations required to estimate LRMC, it may not be practical to develop a sufficiently simple and transparent charging methodology that sets charges precisely equal to LRMC. Despite this constraint, estimates of LRMC should still be used as an objective basis for assessing whether a charging model is cost reflective, and thus which model is most likely to promote efficient decisions by users.[23] Modelling work presented in our October 2013[24] and February 2014[25] reports compares status quo and WACM 2 tariffs to LRMC to evaluate which methodology sends locational signals that are closest to LRMC, and thus which encourages the more efficient locational decisions by generators.

From our comparison of status quo and WACM 2 tariffs to modelled LRMC, we draw several conclusions that are robust across the scenarios we considered:

- First, we find that the locational differences in TNUoS faced by wind generators under both methodologies fail to reflect the extra transmission costs that wind generators in

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21 Connection and Use of System Code, Version 1.6, Section 14.14.6.

22 Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014, Section 2.3.

23 Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014, Section 2.3.

24 Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013, Section 2.3.6.

25 Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014, Chapter 5.

Scotland impose on the system, as compared to those costs imposed by wind generators in England and Wales. WACM 2 compresses the locational signal sent to wind generators, and so exacerbates this problem, and is less cost reflective for wind plants than status quo.

- Second, we find that both charging methodologies signal to peaking gas plants that they impose higher costs in the north of GB than the south, whereas they actually impose a negligible LRMC on the system wherever they locate. WACM 2 compresses the locational signal to peaking plants, so is more cost reflective for this type of generator than the status quo.

For other categories of generators the results were not clear cut. For baseload technologies, the locational signals are similar under status quo and WACM 2, although this conclusion varies slightly across the range of sensitivities we considered. Overall, therefore, we show that neither model addresses the defect in the current charging methodology that "*It does not appropriately reflect the costs imposed by different types of generators (in particular renewable generators) on the electricity transmission network*".[26] Neither methodology produces tariffs close to the LRMC triggered by different generators in different locations, despite the attempts to reflect the "year round" drivers of transmission investment (ALF and diversity) in the WACM 2 charging methodology.

Ofgem therefore mischaracterises our LRMC modelling as being "*not conclusive*".[27] In fact, our analysis shows that WACM 2 sends less cost reflective signals to wind farms than the status quo. Moreover, this finding is very "*conclusive*", as we find the same result across a range of scenarios. Given that improving the cost reflectivity of the charges to renewable generators has been a key aim of the Project TransmiT and CMP213 processes,[28] this evidence suggests that WACM 2 does not achieve its goal, and does not improve on status quo in terms of its cost reflectivity.

2.2.3. It is incorrect and misleading for Ofgem to assert that WACM 2 is closer to LRMC than the status quo

Following its review of our LRMC analysis, Ofgem asserts that "*in most cases the NERA/ICL analysis suggests that WACM 2 is closer to the measure of LRMC than status quo*".[29] Neither the Ofgem consultation nor the accompanying Baringa report give any indication of how Ofgem evaluated which model was closer to LRMC "*in most cases*". However, given that the conclusion of which model produces charges closer to LRMC depends on technology, location and year, in interpreting our modelling results it is essential that Ofgem considers which of the modelled charges are particularly important for ensuring efficient decision making by power generators, as well as the consistency of our findings across the range of scenarios we considered.

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26 Ofgem (August 2013), page 5.

27 Ofgem (April 2014), para 2.12.

28 See, for example: Ofgem (August 2013), page 5.

29 Ofgem (April 2014), para 2.15 and 2.18.

As noted above, WACM 2 makes locational signals less efficient (i.e. less cost reflective) for some technologies, and more efficient (i.e. more cost reflective) for others. In evaluating the case for implementing the new charging methodology, it is therefore important to consider how the mix of improvements and deteriorations in the efficiency of signals will, overall, affect the efficiency of outcomes.

We have made such an assessment in Table 2.1, which summarises the findings of our LRMC analysis. It notes that WACM 2 will probably materially reduce the efficiency of locational decisions made by wind farms. Offset against this, it may increase the efficiency of locational decisions made by peaking plant, but this effect is likely to be small. Finally, it notes that the impact of implementing WACM 2 on the efficiency of locational decisions made by baseload plants is likely to be negligible. Overall, therefore, we infer from the modelling results that WACM 2 is likely to lead overall to less efficient locational decisions by grid users than the status quo.

Table 2.1
Assessment of Likely Impact on Efficiency from Introducing WACM 2

	Relative Performance of SQ vs WACM2			**Assessment**	**Conclusion**
	2013	**2020**	**2030**		
Wind	No difference in locational spreads between SQ and WACM 2.	Across all scenarios, both models understate extra costs of locating wind in Scotland relative to England & Wales, but WACM 2 understates locational spreads by materially more than SQ		• Wind generators have significant discretion over location and trade-offs between transmission costs and regional load factor variation are important for efficiency, as the Baringa modelling in the April 2014 consultation illustrates. • Hence, Ofgem should give high weight to this result that suggests WACM 2 sends less efficient signals to wind farms than SQ.	WACM 2 is likely to materially reduce efficiency of outcomes.
Nuclear	Negligible difference			• Comparison is finely balanced, and in any case, nuclear plants have little locational discretion. • This result does not contribute to the SQ/WACM 2 comparison.	No impact.

	Relative Performance of SQ vs WACM2		
	2013	**2020**	**2030**
Baseload Gas	Negligible difference	WACM 2 provides a slightly more cost reflective locational spread, but this result only holds in the "reference case" and does not hold in our sensitivities, so is not robust to changes in assumptions.	
Marginal Gas	Across our various sensitivities, both models overstate the extra costs peaking generators impose in the north of GB compared to the south, but WACM 2 provides a narrower, and therefore slightly more cost reflective, locational spread.		

Assessment	Conclusion
• Both models signal investment should go into England & Wales and not Scotland, so difference in performance is likely to have little effect. • Gas plants are also more likely to locate in the south of GB for other reasons, such as the likelihood of higher earnings through the balancing mechanism and ancillary service markets. • Hence, the result that SQ sends slightly less efficient locational signals to marginal gas plant should be given little weight in the SQ/WACM 2 comparison.	WACM2 might improve the efficiency of locational decisions for peaking plant, but the effect would be small.

Source: NERA/Imperial

2.2.4. The assumption that the marginal north-south reinforcement will be HVDC (or a similarly expensive alternative) is robust

2.2.4.1. Both WACM 2 and status quo fail to properly reflect the marginal costs of north-south transmission reinforcement

As our February 2014 report describes, one factor contributing to the result that both methodologies (and especially WACM 2) fail to reflect locational variation in the LRMC caused by wind farms is the assumption that the cost of reinforcing the Scotland to England/Wales transmission boundaries is high, and both methodologies "dilute" the marginal cost of these investments when signalling the cost that generators in Scotland impose on the system. In practice, they introduce an element of average cost pricing, as they average the cost of providing onshore and HVDC capacity to reinforce Scotland-England boundaries, even though further reinforcement of the onshore system is heavily constrained.[30]

The use of average rather than marginal cost pricing conflicts with Ofgem's stated intention that "*the costs that triggered* (sic) *by users should be paid for by those users. This promotes cost reflectivity and ensures efficient decisions*".[31] This is in line with the condition set out in the CUSC that the TNUoS charged to users should be "*priced to reflect the incremental costs of supplying them*" (see also Section 2.2.1 above).[32] Therefore, the most efficient and cost reflective transmission charging model would set TNUoS charges equal to the LRMC that each generator imposes on the system, subject to other relevant considerations of tariff design (e.g. simplicity and transparency).

Our assumption that the costs of reinforcing the Scotland-England boundary are higher (on a £/MW/km basis) than the costs of reinforcing the rest of the system is driven by the assumption that it is not practical to develop new onshore overhead lines to provide new Scotland-England transmission capacity due to the difficulties of obtaining planning consents, so other technologies such as offshore HVDC cables are required to provide new capacity.

Hence, the marginal cost of providing additional north-south transmission reinforcement depends on the marginal cost of developing HVDC bootstraps. Accordingly, the marginal cost of accommodating incremental generation capacity in the north depends on the amount of HVDC reinforcement triggered once an incremental (decremental) amount of generation capacity connects to (disconnects from) the system. WACM 2 and status quo, in contrast, both set tariffs based on the average cost of reinforcing the HVDC and AC systems, and so dilute marginal locational signals. WACM 2 dilutes locational signals by more than status quo, so is less cost reflective.

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[30] See: Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 21 February 2014, Section 5.2.3 (amongst other sections that describe this finding).

[31] Ofgem (April 2014), Appendix 2, para 1.65.

[32] Connection and Use of System Code, Version 1.6, Section 14.14.6.

2.2.4.2. Ofgem has challenged our assumption that HVDC is the marginal reinforcement technology for the Scotland-England boundary

Ofgem's consultation states that "*The NERA/ICL model assumes that the marginal reinforcement required on the network between Scotland and England is an HVDC bootstrap*", and that this assumption "*is driving a greater divergence from the measure of LRMC for WACM 2 tariffs for wind generators in these zones than for status quo*".[33]

In light of this observation, Ofgem's April 2014 consultation considers "*how often it is likely that the marginal investment will be HVDC and how large the increased differential is likely to be*".[34] On the question of which transmission technologies will be used to reinforce the Scotland to England boundaries, Ofgem states that:[35]

> "*We consider that the type of future investment to be uncertain. There is likely to be a broader range of investments than assumed by NERA/ICL in its modelling. Some of this investment will be at a cost lower than the cost of the equivalent existing network at current prices. We also consider that fewer HVDC links may be built than currently being considered which gives further weight to this argument. Under the Strategic Wider Works process put in place under the RIIO-T1 price control, TOs must demonstrate that its proposed investment is the most efficient option. This will not always be an HVDC link as other alternative investment options may deliver a better result.*"

2.2.4.3. Our literature review suggests that HVDC will be the marginal reinforcement technology for the Scotland-England boundary

Ofgem's contention is that other transmission technologies besides HVDC could be used to reinforce the Scotland-England transmission boundaries, and that these might be cheaper than "current prices", which we assume constitutes a suggestion that future reinforcement options may be available at a lower cost than the HVDC bootstraps. This statement is not supported by any evidence presented in the Ofgem consultation, and moreover, conflicts with the documentation surrounding the decision to develop the western HVDC bootstrap set out by the Energy Networks Strategy Group (ENSG). ENSG considered the western HVDC investment against the alternatives of:[36]

- A "do nothing" approach, in which constraint costs are higher;
- Reconductoring an existing 400kV double circuit; and
- Installing two new 400kV transmission circuits (one from the East and one from the West of Scotland).

33 Ofgem (April 2014), para 2.14.

35 Ofgem (April 2014), para 2.17.

36 ENSG (2012), *Our Electricity Transmission Network: A Vision For 2020*, February 2012, page 70.

These alternatives "*did not represent the most economic solution*",[37] suggesting that (as of 2012) HVDC boostraps represented the cheapest means of reinforcing the Scotland-England boundaries, and Ofgem's suggestion that alternatives may be cheaper is incorrect. Moreover, presumably Ofgem's decision to allow funding for the Western bootstrap constitutes an acceptance on its part that no cheaper north-south reinforcement options are available.

Moreover, the modelling commissioned by Ofgem for the April 2014 consultation assumes that reinforcement between Scotland and England would require HVDC boostraps, and predicts that new HVDC boostraps (in addition to the western bootstrap) will be developed.[38] Hence, Ofgem's statement that alternatives to HVDC may be available contradicts the modelling it presents in the same document.

Additionally, a range of other recent publications that forecast the future evolution of the British transmission system all predict or assume that more HVDC projects will be required to reinforce the Scotland-England transmission boundaries. For instance, as summarised in more detail in Appendix A, National Grid's latest Ten Year Statement (TYS) includes investment recommendations for reinforcing the transmission system, and shows that the "*limitation on exporting power from Scotland to England*" requires further investment in HVDC: a second Western link, and up to three Eastern HVDC links.[39]

Also, the 2012 ENSG report foresees that the Western HVDC link will be sufficient to resolve transmission constraints on the England-Scotland border until 2018, but further reinforcement is needed thereafter, and a CBA performed by ENSG to compare the effect of installing a 2.1GW Eastern HVDC link against doing nothing found it to be superior. The ENSG only briefly considered other options, but did not state specifically what these options might be, suggesting that additional HVDC is the most likely reinforcement option.[40]

Forecasts made in the ENSG report clearly suggests that it considers the most likely future north-south reinforcement (and hence the least cost of competing investment options) to be HVDC. For example, Figure 2.1 shows that some reinforcement of B6 is possible ahead of the western HVDC commissioning in 2016, but thereafter incremental reinforcement is provided using two additional bootstraps and a very small reconductering project post-2020. Reconductering was considered as an alternative to the ENSG's CBA supporting the western HVDC bootstrap, and this option was shown not to be most economic, so this particular alternative to additional HVDC lines is probably no cheaper, and in any case is small compared to the other HVDC reinforcement projects expected to come online beforehand.

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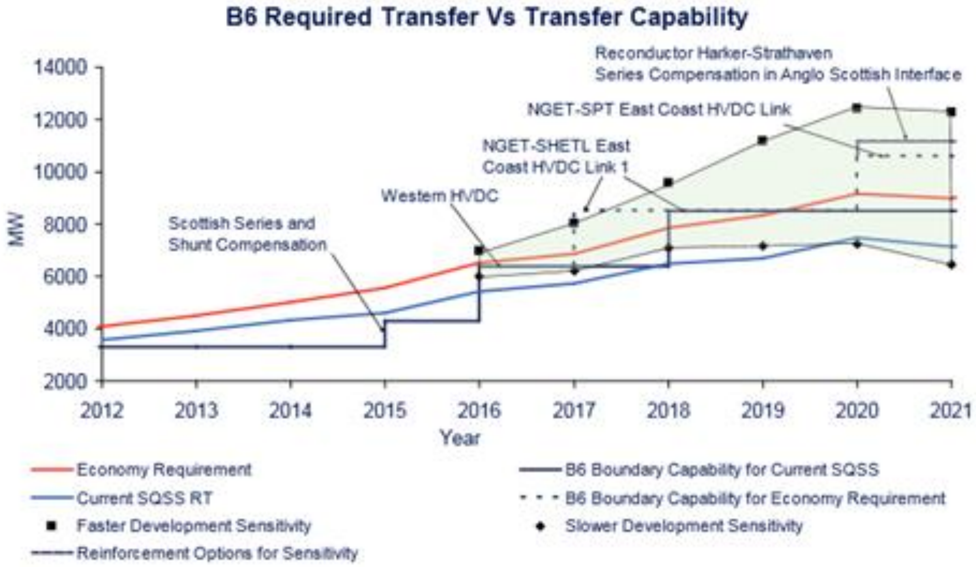
[37] ENSG (2012), *Our Electricity Transmission Network: A Vision For 2020*, February 2012, page 70.

[38] CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, table 15.

[39] National Grid (2013), *Electricity Ten Year Statement*, page 159.

[40] ENSG (2012), page 76

Figure 2.1
Reinforcement of the England-Scotland Transmission Boundary B6



Source: ENSG, 2012.[41]

Overall, the range of evidence we have reviewed provides no support for Ofgem's contention that other technologies besides HVDC could provide the marginal source of reinforcement for the north-south transmission links.

2.2.4.4. Our assumptions are therefore reasonable, and Ofgem's arguments that they exaggerate differences between WACM 2 and LRMC have no merit

Accordingly, our finding that the LRMC of transmission triggered by incremental generation capacity connecting in Scotland reflects the assumed cost of the HVDC bootstraps, or some transmission technology with costs higher than the cost onshore AC reinforcement, appears reasonable with reference to the published sources we have reviewed. Ofgem does not support its assertion that alternative transmission technologies may be available to reinforce the Scotland-England boundaries with any evidence or examples. However, whatever alternative transmission reinforcement options exist would probably be more expensive than HVDC on the basis that the decision to build the HVDC link concluded that no cheaper option was available.

Hence, Ofgem's arguments that our cost reflectivity modelling exaggerates the differences between the signals conveyed by WACM 2 as compared to LRMC have no basis in the evidence presented by Ofgem or in the evidence we have reviewed. As a consequence, Ofgem has presented no evidence to challenge our the modelling results we presented that indicate that WACM 2 sends less cost reflective signals than status quo, and there is therefore no evidence to support the introduction of WACM 2 on grounds of cost reflectivity.

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[41] ENSG (2012), page 76

2.2.4.5. The suggestion that other technologies may play some role is irrelevant for sending efficient marginal cost signals

Also, Ofgem's suggestion other technologies besides HVDC may play some role in reinforcing the Scotland-England boundary is not relevant to the assessment of which charging methodology promotes the most efficient outcomes:[42]

> "*We consider that the type of future investment to be uncertain* (sic). *There is likely to be a broader range of investments than assumed by NERA/ICL in its modelling. Some of this investment will be at a cost lower than the cost of the equivalent existing network at current prices. We also consider that fewer HVDC links may be built than currently being considered which gives further weight to this argument.*"

Even if there does exist some limited number of investment projects that use alternative transmission technologies that are cheaper than HVDC to upgrade Scotland-England links, our literature review suggests that, because most sources forecast substantial HVDC reinforcements, they would be relatively small, and so HVDC would still provide the marginal source of reinforcement.

Because efficient access pricing requires that tariffs reflect marginal costs, signalling the average cost of constrained low cost reinforcement options and unconstrained high cost reinforcement options (i.e. average, not marginal cost pricing) would not promote efficiency. Hence, Ofgem's statement that some reinforcements may be provided by technologies besides HVDC, even if this is the case, does not detract from the need to signal the marginal cost of HVDC bootstraps through locational TNUoS charges in order to promote efficiency.

2.2.5. Ofgem's decision not to conduct its own cost reflectivity modelling is inconsistent with its decision to perform welfare modelling

The Ofgem consultation indicates that it has decided not to perform its own cost reflectivity modelling to compare status quo and WACM 2 tariffs to the LRMC of transmission reinforcement.

This decision is based on the argument that such modelling would require "*subjective projections about future levels and types of generation and the required level of transmission reinforcement. These projects are highly uncertain but have a large impact on results… In carrying out our own modelling, we would be required to develop our own methodology and make our own simplifying assumptions*".[43] This statement is equally true of the welfare modelling Ofgem commissioned from Baringa, so this reasoning is inconsistent with other aspects of the minded-to decision.

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[42] Ofgem (April 2014), para 2.17.

[43] Ofgem (April 2014), para 2.19.

2.2.6. Baringa's latest report has attempted cost reflectivity analysis, but it is incomplete and makes the wrong comparison

Baringa has attempted some quantitative cost reflectivity analysis.[44] This analysis provides some preliminary indication that supports the findings of our LRMC analysis, i.e. that, when compared to status quo, WACM 2 understates the additional transmission costs that wind generators impose on the system in Scotland relative to England and Wales, and that both charging models, and status quo in particular, overstate the extra transmission costs caused by a peaker in Scotland relative to England and Wales.

However, Baringa's analysis is incomplete as it only considers a single year and two transmission zones. It also compares incremental constraint costs to tariffs, not incremental reinforcement costs. It is therefore less comprehensive and less reliable than the NERA/Imperial modelling described in our February 2014 report. However, as far as we can tell from our review of the Ofgem consultation, Ofgem has ignored this analysis in forming its conclusions.

2.2.7. Ofgem's conclusion that WACM 2 reflects the SQSS is based on unsound reasoning

2.2.7.1. Ofgem's consultation provides an interpretation of the transmission planning standards in the SQSS

Ofgem's consultation states that:[45]

> "*We think there is a misunderstanding in the way in which some respondents have understood the alignment of WACM 2, in particular the Year Round tariff element, to the SQSS and the way in which planning is carried out in reality using the SQSS framework. We support NGET's interpretation of the SQSS and its translation into the TNUoS methodology under CMP213"*.

Ofgem then goes on to explain how it (and/or NGET) thinks the SQSS should be interpreted. Ofgem notes that:[46]

> "*The two deterministic rules in the SQSS reflect a set of pre-determined requirements to establish the extent to which network reinforcement is required. The first of these only consider the requirements to reinforce the network based on times of peak demand. The second of these, the Economy criterion, has been developed as a representative 'snapshot' of the required level of efficient transmission investment that would be derived from a cost benefit analysis (CBA). This is in addition to that required for peak demand and is the level of investment required to efficiently manage constraint costs*".

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[44] CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, Section 2.3.

[45] Ofgem (April 2014), Appendix 2, para 1.5

[46] Ofgem (April 2014), Appendix 2, para 1.7.

For the reasons described in more detail below, whatever "misunderstandings" Ofgem thinks respondents have in the appropriate interpretation of the SQSS, Ofgem itself has not presented any evidence or cogent reasoning to show that WACM 2 signals the costs that TOs incur to accommodate incremental generation in compliance with the SQSS, even under its own interpretation of the SQSS planning standards.

2.2.7.2. The SQSS contains three conditions that drive transmission investment requirements

As discussed in our previous report,[47] the economy and demand security criteria backgrounds in the SQSS represent the minimum level of investment that the TOs are obliged to provide under their licences. Moreover, while the economy criterion background may be designed to prescribe the level of investment that would be prescribed by a CBA, in practice, the document itself obliges the TOs to provide at least the volume of investment required to conform with this standard, irrespective of whether this turns out to be higher or lower than the volume that a full CBA would actually prescribe.

In addition, as Ofgem notes, these deterministic rules *"cannot capture specific regional circumstances. Therefore, the SQSS also provides for consideration of 'conditions in the course of a year of operation'. This recognises that a full CBA may be required in reality and that larger investments require more than a single 'snapshot' study to establish their justification"*.[48] In other words, TOs are also obliged to provide additional transmission investments, on top of those prescribed by the combination of the demand security and economy criteria, where those additional investments are justified by a CBA. However, the SQSS does not allow the TOs to provide less capacity than prescribed by combination of the two deterministic criteria, even if a CBA suggests this is the efficient solution.

2.2.7.3. Ofgem's interpretation of the SQSS does not justify the supposed link to WACM 2 tariffs

Ofgem then goes on to explain that:

> "*Both the Economy criterion and 'conditions in the course of a year of operation' incorporate a CBA. This is an economic assessment weighing up the cost of current and future constraints against investment costs. The results are influenced by the output of generators behind boundaries and the plant mix in that area. This is consistent with the use of ALF and the sharing factor used in calculating the Year Round tariff under WACM 2. We therefore consider that WACM 2 is consistent with the SQSS*".[49]

This statement misrepresents the obligations imposed on TOs by the SQSS. Firstly, the SQSS imposes an obligation on TOs to provide at least as much capacity as prescribed by the

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[47] Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013, Section 2.2.

[48] Ofgem (April 2014), Appendix 2, para 1.7.

[49] Ofgem (April 2014), Appendix 2, para 1.8.

economy and demand security criteria. Even if the intention of the economy criteria was to "*incorporate a CBA*", in practice it simply imposes a deterministic obligation on TOs. The derivation of WACM 2 year-round tariffs uses the same generation/demand background as the economy criterion, but the economy criterion does not involve the use of ALFs or diversity factors. The use of these factors is a departure from the specific provisions of the economy criterion in the SQSS.

Secondly, the statement that optimal transmission investments depend (in a CBA framework) on "*the output of generators behind boundaries and the plant mix in that area*" will only be relevant to the costs actually incurred to comply with the SQSS if such a CBA prescribes that more capacity should be provided than the minimum levels that TOs are required to provide under the SQSS. Ofgem's consultation does not consider whether the obligation to conduct a full CBA or obligation to comply with the economy criterion is driving investment requirements on the transmission system.

Additionally, the final statement in this paragraph is speculation that is not supported by any evidence or analysis. Specifically, Ofgem states that "*the use of ALF and the sharing factor used in calculating the Year Round tariff under WACM 2*" is consistent with the observation that the results of a CBA depend on "*the output of generators behind boundaries and the plant mix in that area*". This statement lacks a logical foundation. The observation that ALF is included in the WACM 2 tariff calculation, and that plant load factor is a driver of optimal transmission reinforcements in a CBA, do not combine to prove that WACM 2 tariffs reflect the costs generators impose on the system more accurately than status quo tariffs.

WACM 2 could, at best, be considered a proxy for the costs generators impose on the system, and how close a proxy it is can only be appraised objectively by comparing estimated WACM 2 tariffs to the LRMC that the generators who pay those charges impose on the transmission system. This is something that Ofgem has still failed to do. The only attempt to perform such an analysis during the consultation process (or beforehand) was presented in recent NERA and Imperial reports, and as described elsewhere in this report, this analysis does not support the introduction of WACM 2.

2.3. Ofgem's Qualitative Evaluation on Cost Reflectivity

Ofgem believes that because WACM 2 introduces a dual background into charging, and because the NETS SQSS also uses a dual background, that WACM 2 must be more cost reflective than status quo.[50] This position is no more than a belief without foundation in analysis or tangible evidence, and the reasoning underpinning it is flawed.

The SQSS contains, not just a dual background, but also a requirement that more reinforcement should be provided if it is justified by CBA. WACM 2 attempts to reflect this additional driver through ALF and diversity adjustments, but Ofgem has no basis for concluding whether or not the charges resulting from these adjustments are more cost reflective than the status quo.

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50 Ofgem (April 2014), para 2.18.

Hence, superficially, WACM 2 appears to reflect the SQSS. Accordingly, Ofgem's consultation makes a series of vague assertions that WACM 2 reflects the costs users impose on the system because it includes a dual background, and includes plant load factor and diversity in the calculation of tariffs.[51]

However, the crucial problem with WACM 2 is the way and extent to which these factors are "reflected". Even if generators with higher ALF impose higher transmission costs on the system, it is not sufficient to conclude that linking charges to ALF necessarily reflects costs more closely that an alternative that does not include ALF in the formula.

In other words, whether a methodology in which charges are a function of ALF reflects costs more closely than an alternative methodology that does not use ALF depends on how the relationship between ALF and charges is formulated in an equation or calculation procedure, and how any formulaic relationships are parameterised. Ofgem has not investigated whether either of these crucial aspects of the WACM 2 charging model produce cost reflective charges, or charges that are more cost reflective than status quo.

2.4. Ofgem's Overall Assessment

Ofgem concludes that "*On balance, we think that the potential benefits of greater cost reflectivity for the GB system as a whole outweigh the risks that WACM 2 may result in less cost reflective charges in certain circumstances*".[52] Our analysis shows that the cost reflectivity of WACM 2 is particularly poor for those "certain circumstances" that are particularly likely to lead to inefficient decision making as a result of inefficient transmission charges (i.e. the locational signals sent to wind farms), as generators have significant locational discretion, and face a trade-off between load factor and TNUoS. For other types of plants the trade-off between locational TNUoS and other factors is less important. The difference between WACM 2 and status quo tariffs for baseload generators is marginal, and peaking plants would almost always locate in the south of GB under both charging models.

Ofgem's conclusion that "*this risk* [that WACM 2 may result in less cost reflective charges] *is considerably lower than that implied in the NERA/ICL modelling*"[53] appears to be based on the assertion that HVDC may not be the marginal reinforcement option. As described above, our research suggests that most studies of the long-term evolution of the GB transmission system clearly identify HVDC as the marginal investment option for the Scotland to England boundary.

Ofgem suggests that "*there is the potential to mitigate this risk if it does materialise through other modifications to the transmission charging arrangements"*.[54] This statement demonstrates that, given the material risk that WACM 2 is not cost reflective, the proposed methodology will be subject to further regulatory change, and so it is not stable or predictable,

[51] See, for example, Ofgem (April 2014), para 1.20.

[52] Ofgem (April 2014), para 2.20.

[53] Ofgem (April 2014), para 2.20.

[54] Ofgem (April 2014), para 2.20.

and investors cannot rely on the signals it conveys. Even in the cases where WACM 2 does send more cost reflective signals than status quo, the resulting uncertainty about the sustainability of the methodology will undermine investors' confidence in it, and reduce the extent to which they respond to the signals it sends.

Ofgem also states that "*We are also not persuaded by any of the arguments included in the consultation responses which seek to demonstrate that WACM 2 is less reflective of the impact different users have on the transmission system than the current ICRP methodology*".[55] As described above, the LRMC modelling we have performed provides quantitative evidence that proves that WACM 2 is less reflective of the impact different users have on the transmission system than the current ICRP methodology in a number of important respects. Given there is no competing evidence that demonstrates that the evidence provided by this study is invalid, Ofgem is wrong to draw this conclusion.

Finally, Ofgem concludes that "*we continue to think that WACM 2 better promotes competition and better reflects developments in the transmission licences' transmission businesses for the reasons set out in our August 2013 consultation*".[56] From the August 2013 consultation,[57] it appears that Ofgem reaches this conclusion primarily from its assessment of cost reflectivity,[58] but as noted above, the evidence presented since the August consultation suggests that WACM 2 is less cost reflective than status quo. Therefore, this conclusion is also flawed.

As a result of these failings, Ofgem's conclusion that "*WACM 2 better facilitates the CUSC objectives than the status quo"*[59] is not supported by evidence, and moreover, is not based on a logically coherent foundation.

55 Ofgem (April 2014), para 2.21.

56 Ofgem (April 2014), para 2.22.

57 Ofgem (August 2013), para 6.103-6.106.

58 In terms of the choice between WACM 2 and status quo, other changes to the methodology to include HVDC and island links in the WACM 2 charging model are not relevant, as they are common to both models.

59 Ofgem (April 2014), para 2.23.

3. Ofgem's Assessment of Consumer Benefits

3.1. Introduction

As well as its view that WACM 2 is more cost reflective than the status quo, Ofgem's minded to decision in August 2013 was based on modelling results that suggested it would reduce power sector costs over the period to 2030, and reduce customer bills:[60]

> "*We think that implementing this option will be in the interests of existing and future consumers. This is primarily because we consider it to be the most cost reflective of the options presented to us and therefore drives more efficient decisions by market participants and policy makers which creates value for consumers. This view is supported by the modelling analysis submitted to us by industry which suggests that between 2020 and 2030 consumer bills could be up to £8.30 per annum lower than under the current methodology.*"

However, in response to the August consultation, Ofgem received a range of feedback on this modelling work,[61] including in a report by NERA and Imperial.[62] In response to this feedback, and to better reflect recent developments in the Electricity Market Reform (EMR) programme, Ofgem commissioned Baringa to update the modelling work Ofgem relied on in August 2013.[63]

This chapter reviews the new evidence and arguments presented by Ofgem in its April 2014 consultation paper on the likely impact on current and future consumers from the introduction of WACM 2. It therefore supplements our October 2013 review of the Ofgem Impact Assessment and minded-to decision.

3.2. Ofgem's Revised Impact Assessment

3.2.1. Baringa's estimates of the quantifiable costs and benefits

The updated Baringa modelling indicates that the introduction of WACM 2 would lead to an increasing share of wind generation in Scotland, which, because it assumes wind load factors are higher in Scotland than in England and Wales, leads to lower generation costs. However, transmission costs increase because of the need to transport increased amounts of power from Scottish wind farms to the rest of Britain. The balance of these effects is that Baringa estimates that power sector costs will increase due to WACM 2 (in present value terms) over the period to 2020, but fall between 2020 and 2030. Over the whole period to 2030, Baringa's modelling suggests a small savings in power sector costs from the introduction of the WACM 2 methodology.

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[60] Ofgem (August 2013), page 6.

[61] Ofgem (April 2014), para 2.26.

[62] Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013.

[63] Ofgem (April 2014), para 2.27.

The modelling also estimates the impact on costs to consumers from the introduction of WACM 2. The modelling shows that consumers' bills will rise as a result of WACM 2 throughout the whole period to 2030. As well as higher transmission system costs, this result emerges because wholesale power prices (both in the energy and capacity market) increase as a result of the reform to TNUoS arrangements. Specifically, WACM 2 increases the price to which wholesale energy and capacity prices need to rise to remunerate investment in the most expensive new thermal generation capacity required to meet demand. Because the marginal cost of new thermal generation investments is higher under WACM 2, the wholesale costs increases, which increases consumers' bills.[64]

3.2.2. Baringa's modelling probably overstates the cost saving from WACM 2

3.2.2.1. The result hinges on the incorrect assumption that wind load factors are systematically higher in Scotland than England and Wales

Ofgem believes the "*small reduction in power sector costs under WACM 2*" arises because WACM 2 "*unlocks higher yielding renewables sites, particularly in Scotland*".[65] While it is true that, on average, wind load factors tend to be slightly higher than at onshore sites in England and Wales, our analysis shows that, contrary to what Baringa assumes, it is not *systematically* true that Scottish RES sites have higher load factors. That is, there are a large number of high load factor sites in both Scotland and England and Wales.

Using data from Ofgem E-Serve, which records the number of Renewable Obligation Certificates (ROCs) issued to generators in the UK, we have examined the distribution of wind load factors achieved by wind generators throughout Britain between 2011 and 2013 (inclusive).[66] More details of this analysis are presented in Appendix D.

As Table 3.1 shows, average load factors between 2011-2013 were higher on average in Scotland (28.4%) than in England (24.6%) and Wales (25.6%). However, these simple averages give a misleading impression.

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64 Modelling work by NERA and Imperial submitted to Ofgem in response to the August 2013 consultation sets out the same argument, and identifies an increase in customer bills in response to WACM 2. See Project TransmiT: Modelling the Impact of the WACM 2 Charging Model, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013, Sections 3.1.3 and 3.2.4.

65 Ofgem (April 2014), para 2.39.

66 The database includes some generators that did not receive ROCs in every month from 2011-2013. We excluded these generators to avoid biasing the results because, for example, they only operated in particularly windy periods. We were left with a sample of 105 wind generators located in England (approximately 3.2 GW), 22 wind generators located in Wales (approximately 0.5 GW) and 87 wind generators located in Scotland (approximately 2.4 GW).

Table 3.1
Load Factors (2011 - 2013) At Generators Across Great Britain

	England	Scotland	Wales	England & Wales
Mean	24.6%	28.4%	25.6%	25.0%
Std. Dev.	6.7%	8.7%	6.1%	6.6%
n	105	87	22	127

Source: NERA analysis of Ofgem data.

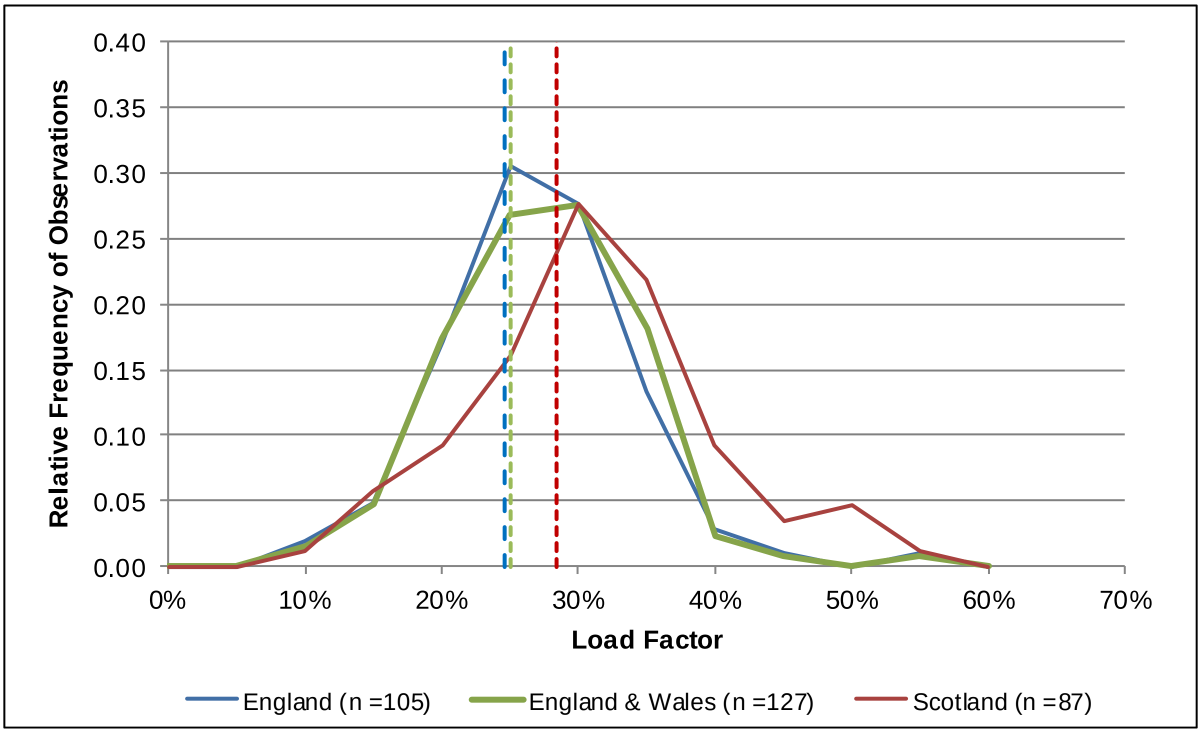
As Figure 3.1 shows, there is significant overlap in the distributions of load factors achieved by wind farms in England, Scotland and Wales. The implication of this finding is that increasing TNUoS to English and Welsh wind farms disadvantages some sites with high load factors, even if it benefits somewhat more wind farms in Scotland with high wind load factors.[67] In contrast, Baringa's assumption that all wind farms in Scotland have higher load factors than all wind farms in England and Wales will tend to exaggerate the effects of changing TNUoS on wind generators' locational decisions. By implication, the generation cost savings that Baringa identifies are overstated.

Hence, the Baringa load factor assumptions for onshore wind materially understate the variation in load factors seen in reality.[68] This shortcoming, sometimes referred to as "aggregation bias", is likely to bias the sensitivity of wind investment decisions that Baringa identifies.

[67] Specifically, our analysis suggests the probability that any randomly selected wind site in England and Wales has a higher load factor than a randomly selected wind site in Scotland is around 37%.

[68] The same problem applies to offshore wind, where our analysis of wind intensity data suggests substantially more variation in wind load factors is likely than Baringa assumes.

Figure 3.1
Distributions of Load Factors at Wind Sites Across Britain



Source: NERA analysis of Ofgem data.

3.2.2.2. Baringa's framework underestimates transmission system costs, so probably understates the extra costs of WACM 2

As well as exaggerating potential generation cost savings, Baringa's modelling framework ignores the impact of unit commitment costs and dynamic constraints when calculating constraint costs, as we pointed out in our recent review of the Ofgem Impact Assessment:[69]

> "*NERA/ICL point out their approach to modelling dispatch is superior to that in National Grid's ELSI model since it takes into account unit commitment and dynamic constraints. This may be true but we do not consider that this materially affects the results in this context. In designing the TransmiT modelling framework we actively took the decision to use the simplified ELSI model over a more detailed market dispatch model, such as PLEXOS, in order to speed up run times. However, we used PLEXOS to calibrate key outputs from ELSI such as constraint costs.*"

In fact, Baringa's benchmarking of the constraint costs emerging from ELSI to those emerging from a comparable PLEXOS run showed that ELSI systematically understated constraint costs as compared to the more detailed PLEXOS run. Higher constraint costs, taking transmission investment costs as given, should result, in an efficient modelled equilibrium, in higher transmission investment. For any given change in generation

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[69] CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, page 23.

locational decisions, we would expect Baringa's approach to understate the impact of WACM 2 on transmission constraint costs and/or transmission investment costs.

However, it would be necessary to perform a PLEXOS run using Baringa's latest setup of the model to verify whether this is the case. In particular, as noted above in Section 3.2.2.2, our analysis suggests that Baringa's framework may overestimate the impact on generators' locational decisions due to WACM 2. Hence, while the modelled impact on transmission system costs may be understated due to this flaw in Baringa's approach, we cannot be sure by how much.

Hence, Baring's modelling may understate the increase in transmission costs resulting from introducing WACM 2, and at the same time, as noted in Section 3.2.2.1 above, it probably overstates the generation cost savings because of the implausible assumption that all Scottish wind sites offer higher load factors than those in England and Wales.

3.2.2.3. We have identified other problems with the Baringa modelling

As well as these factors, which lead us to conclude that the Baringa model understates the net cost of implementing the WACM 2 charging model, we have identified a number of other problems with the Baringa modelling approach. However, it is difficult to identify whether these problems will lead to an under or an overstatement of the impact of WACM 2.

Firstly, Baringa has used an imperfect foresight approach, which assumes that investors in generation and transmission assets systematically ignore known and expected changes in costs and revenues that occur more than 5 years into the future. As described in Appendix B, there is no theoretical or practical basis for this approach, which is devoid of economic rationale.

Baringa also mischaracterises the approach used by NERA/Imperial as a "perfect foresight" approach, in which investors have full knowledge of the future. This characterisation does not assume that investors have perfect information, as Baringa suggests.[70] Rather, it assumes that investors form an expectation about how costs and other conditions will develop over the whole of the remaining modelling horizon, and represent the risk and uncertainty around these forecasts by discounting future cash flows at a market-based discount rate.

Secondly, the assumption that there will be a fixed split between the amount of onshore wind and offshore wind developed in the British market is not supported by statements of current government policy on the expected allocation of renewables. In fact, the government has not fixed a split between onshore and offshore wind that it will target out to 2030. Rather, government has the flexibility to optimise this mix as new information becomes available on the cost of competing renewables technologies, including TNUoS.[71] In the long-run the fixed split between onshore and offshore wind is not realistic. Government can change decisions regarding the mix it targets in response to information on cost and resource potential, and cost

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70 CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, page 22.

71 Ofgem's April 2014 consultation appears to recognise this possibility for government to adjust the renewables mix in response to changes in TNUoS. See paragraph 2.43.

reflective TNUoS could (and should) form part of this assessment. We provide more discussion of this topic in Appendix C.

3.2.3. Ofgem is wrong to dismiss estimated consumer bill increases following the introduction of WACM 2

Although the modelling shows that the impact on consumers would be negative from WACM 2, Ofgem considers other "dynamic effects" that it believes lead the modelling to understate the benefits of WACM 2.[72] In particular, Ofgem states that:[73]

> "*We think that the modelling of power sector costs is likely to be a more accurate illustration of the impact of WACM 2 on the sector as a whole than the results for consumer benefit. Modelling consumer benefit relies on the interaction with the capacity mechanism and it is uncertain how the introduction of this mechanism will drive behaviour. The modelling of power sector costs does not rely on assumptions about this.*"

This paragraph contains two incorrect statements. Firstly, the finding that customer bills rise as a result of WACM 2 does not rely on assumptions about "*interaction with the capacity mechanism*". In a competitive power market, in order to remunerate continued investment in power generation capacity, market mechanisms need to provide sufficient remuneration to power generators to allow them to cover their variable and fixed costs. Hence, in a credible economic equilibrium, energy and capacity prices need to rise to a level that covers the total costs, including TNUoS, of the marginal new entrant. This result holds irrespective of how the capacity market "interacts" with the TNUoS regime or the energy market; it is based on the simple fact that, to attract new investment, prices must be set at a level that remunerates marginal investment costs.

In the British power market, the marginal source of new entry is likely to be gas-fired CCGT, or possibly OCGT, as both the NERA/Imperial and Baringa modelling suggests. Moreover, as both modelling studies show, the marginal new entrant will probably be located towards the south of GB where the TNUoS charges faced by CCGTs are likely to rise under WACM 2.[74] Hence, it is likely that energy and capacity prices will increase as a result of WACM 2.

Ofgem's paper also suggests that Baringa's "alternative case" illustrates the sensitivity of results to assumptions regarding the future marginal plant, and suggests that the consumer impact is less if no capacity is procured through the CPM.[75] However, the fundamental result that the marginal new entrant plant, which is still southern CCGT in Baringa's alternative

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72 Ofgem (April 2014), para 2.40.

73 Ofgem (April 2014), para 2.41.

74 (1) CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, table 16; and (2) Project TransmiT: Modelling the Impact of the WACM 2 Charging Model, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013, table 3.5.

75 Ofgem (April 2014), para 2.44.

case,[76] needs to recover its costs (including any increase in TNUoS under WACM 2), still holds even if capacity is remunerated through the energy market.

The second problem with the statement above is Ofgem's assertion that the modelling of power sector costs does not rely on assumptions about interactions with the capacity mechanism. In Baringa's framework, the model that produces estimated power sector costs is the same as the model that produces price impacts. The model's decisions regarding generation investments taken through interaction with the capacity mechanism affect both modelled prices and modelled costs. Hence, Ofgem's statement is wrong.

3.2.4. Some of the "dynamic effects not modelled" that Ofgem identified have been modelled, so do not merit additional consideration

Ofgem suggests that higher prices under WACM 2 will result in higher generator profits, which may attract new entry into the power market, and thus put downward pressure on prices.[77] Our understanding of the Baringa modelling framework is that it simulates generators' optimal entry and exit decisions over the modelling horizon, with generators taking these decisions in response to price signals observed in the market.

Therefore, either Ofgem's suggestion that the consumer bill effects will be eroded by new entry into the power market is incorrect and is based on a misunderstanding of the Baringa framework, or Ofgem is asserting that the Baringa modelling framework is not a reliable basis for forecasting the evolution of the power market and estimating price and cost effects from the change in charging methodology.

Hence, because the possibility of new entry eroding changes in generators' profits has been modelled, it merits no further consideration.

3.2.5. Other "dynamic effects" hinge on the unsupported assertion that WACM 2 is more cost reflective

Ofgem then refers to a range of "*long term effects*" that the modelling does not take into account:[78]

> "*In particular, it becomes increasingly more difficult to make meaningful assumptions about factors influencing the market over the longer term (such as policy development or market behaviour). It is also difficult to draw any conclusions using the existing modelling about likely benefits or costs post 2030, the end of the modelling period. But as WACM 2 results in more cost reflective charges, we consider this will bring benefits not captured in the modelling both within the period and beyond it. We would expect to see current and future generators responding efficiently to more cost reflective charges and to any short term increase in profits. This would give policy makers a clearer picture of the market to make efficient decisions and supports the*

76 CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, table 17.

77 Ofgem (April 2014), para 2.42.

78 Ofgem (April 2014), para 2.43.

> *long term efficiency of the energy market. For instance, we consider that the sustainability benefits of WACM 2 discussed further below would support policy makers to develop mechanisms in delivering long term renewables targets at lower cost."*

Ofgem's argument that the WACM 2 delivers benefits post-2030 and benefits from sources that have not been modelled, such as supporting more efficient long-term policy regarding renewables, hinges on its belief that WACM 2 is more cost reflective than the status quo. As discussed in Chapter 2 above, Ofgem has no basis for this belief in either reliable evidence or logical reasoning.

3.2.6. Ofgem's discussion of non-monetised sustainability benefits shows they should carry no weight in the assessment of WACM 2

Ofgem believes that WACM 2 increases the "*likelihood of meeting renewables targets for a given low carbon support budget*".[79] This assertion relies on the hypothesis that renewable resources will have lower TNUoS under WACM 2, which is not necessarily true if they are running a high load factors (e.g. biomass) or are located in England and Wales. Moreover, there is no basis for the suggestion that WACM 2 will help meet renewables targets more efficiently, as Ofgem has no reliable evidence that it is more cost reflective than the status quo, and our own analysis suggests it may be less cost reflective.

This statement also assumes that, in the long-run, the budget for supporting renewable generators is fixed. In practice, this budget is not fixed, and government has discretion to change the mix of nuclear, CCS and the various renewable technologies it targets in response to new information on the costs and resource potential of these technologies. Using the most cost reflective TNUoS regime should support efficient decision making regarding the long-term generation mix, in a way that accounts for the whole-system impact of competing low carbon generation technologies.

Also, Ofgem's speculation that "*meeting long term renewable targets (eg beyond 2030) will require more renewable technology and incentives for renewable developers to innovate and develop their technologies (such as tidal and marine technology). The broader range of renewables technologies that might be developed under WACM 2 contributes to benefits in terms of energy mix*"[80] is equally illogical for the same reasons.

3.3. Conclusions

The quantitative modelling commissioned by Ofgem concludes that consumer bills will increase as a result of implementing the WACM 2 charging model. This finding is consistent across the range of modelling scenarios considered by Baringa.[81] Despite the Authority's principal objective of protecting consumers' interests, Ofgem's latest consultation seems to

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[79] Ofgem (April 2014), para 2.47.

[80] Ofgem (April 2014), para 2.48.

[81] CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, tables 19 and 20.

place little weight on this finding when concluding that the latest evidence does not lead it to change its minded to decision to implement WACM 2:[82]

> "*While we have always believed that modelling of this kind is illustrative, this additional uncertainly strengthens the view that we should not consider results as definitive but as part of wider range of evidence to look at collectively.*"
>
> "*Although the impact assessment modelling does not present clear evidence that the monetised benefits of WACM 2 outweigh the costs, we consider that the cumulative impact of factors not included in the modelling would reverse this effect in the long term...*
>
> *Overall, we think that the actual impact of implementing WACM 2 is likely to be long term benefits to consumers not all of which have been captured in the impact assessment modelling.* ***We therefore consider that implementing WACM 2 is in line with our statutory duty to protect the interests of current and future consumers.***"

Ofgem cites several "uncertainties" that lead it to place little emphasis on this analysis. However, for the reasons set out above, none of these uncertainties would reverse the conclusion that the introduction of WACM 2 is not likely to benefit current and future consumers. In fact, the result that consumers face higher bills as a result of WACM 2 is consistent with (1) the need for new entrants to recover their fixed development and operating costs through the market, and (2) the features of WACM 2 that increase the TNUoS costs faced by these marginal new entrants. We have also identified a number of other factors that mean the modelling commissioned by Ofgem from Baringa probably understates the overall cost of introducing WACM 2.

Given the low reliance Ofgem places on the quantitative modelling, the decision not to revise its minded to decision appears to be based primarily on non-monetised benefits that it believes would result from introducing WACM 2. However, Ofgem has not presented any evidence to suggest the non-monetised benefits will outweigh the negative financial impact on consumers indicated by Baringa's model. Moreover, these benefits stem from the belief Ofgem holds that WACM 2 is more cost reflective than the status quo methodology, and would therefore improve the efficiency of locational decisions taken by generators. As discussed in Chapter 2, Ofgem has not presented any evidence or logical argument to support this belief that WACM 2 is more cost reflective than the status quo.

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[82] Ofgem (April 2014), para 2.38 and para 2.49-2.50. Original emphasis.

4. Omissions from Ofgem's Assessment

Ofgem's updated consultation has failed to address a number of key problems with the WACM 2 charging methodology, and omissions from the Impact Assessment that we identified in response to the August 2013 consultation.

4.1. Distributional Effects

In our review of the Ofgem Impact Assessment, we noted that Ofgem had 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 standard for weighing up the harm caused by the significant distributional effects of the reforms against any supposed efficiency savings.[83] Ofgem's latest consultation acknowledges this feedback from respondents, noting that "*some respondents did raise concerns in relation to consistency and differential treatment".* It then lists a series of points including:[84]

> "*Our initial assessment failed to account for the distributional effects of the proposed change, particularly the risk that the change will add to perceptions of regulatory risk and increase costs to consumers through higher financing costs.*"

However, in the three paragraphs that follow, in which Ofgem sets out its views in response to this and other criticisms, Ofgem fails to mention the potential additional cost imposed on consumers from the introduction of WACM 2 as a result of distributional effects. Hence, Ofgem has still failed to quantify the distributional effects caused by the reform in any published document, and has not evaluated the effect of any such change on consumers.

As described in detail in our previous report, the increase in perceived regulatory risk from regulatory interventions that materially redistribute value around the industry, especially where those regulatory interventions are not justified on the grounds of enhancing efficiency, will tend to increase the perception of regulatory risk in the sector, inflate financing costs, and so impose additional costs on consumers. This factor is a non-monetised cost that would shift the balance of evidence towards the status quo away from WACM 2, and it is a factor Ofgem has consistently ignored throughout its consultation process.

4.2. Distorting Trade with Neighbouring Markets

In our review of the Ofgem Impact Assessment, we noted that the WACM 2 charging methodology, by linking transmission infrastructure charges to generators' output,[85] could distort trade with neighbouring markets, as generators in other EU Member States tend not to

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[83] Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013, Section 3.2.

[84] Ofgem (April 2014), Appendix 2, para 1.54.

[85] By producing an extra MWh today, a generator increases its ALF (at least in 3 out of 5 years, reflecting the averaging procedure used in WACM 2) for the subsequent five years. Hence, WACM 2 is, in effect, an energy based transmission charge that can distort dispatch and trade with neighbouring markets.

face these energy-linked charges.[86] Ofgem's latest consultation notes this criticism, and states that "*We agree with respondents that the use historical ALF will have an impact on generator dispatch decisions*".[87] In response, Ofgem commissioned Baringa to model the impact on plant dispatch from introducing the new link between energy production and TNUoS costs under WACM 2. Ofgem's summary of Baringa's modelling states that:

- "*The distortion would provide a signal for generators in the south to run more and those in the north to run less.*
- *As a consequence of more southern plant running, any generation cost increases due to distortion are likely to be outweighed by larger reductions in constraint costs and transmission losses.*
- *Baringa's analysis (on the Original Case) indicates that prices would decrease by an average of £0.05/MWh across the period of analysis.*

> […] *The conclusion of this work is that the impact on generator dispatch decisions would be minimal and, based on the modelling approach adopted by Baringa, potentially outweighed by movements in other parameters. We therefore disagree with the suggestion that the impact could be significant and potentially distort trade with other EU member states.*"

Hence, Ofgem's response to the potential for distorting trade between neighbouring markets does not actually consider the effect on trade with neighbouring markets at all, and focuses solely on the impact of WACM 2 on dispatch within the British market. Baringa's report, in contrast, does admit that imports increase under WACM 2.[88] Given that this change in imports does not result from a change in cost conditions in either Britain or neighbouring markets, and only the introduction of an energy-based TNUoS regime in Britain, this analysis appears to confirm our hypothesis that WACM 2 will distort trade with neighbouring markets.

4.3. Implementation of the Target Model

Under the EU Target Model, market zones need to be defined with reference to transmission boundaries across which persistent congestion arises. This may require some degree of market splitting in the British market, which would have the effect of pricing congestion into the energy market to a greater degree than can be achieved with a uniform national wholesale price, as exists currently under BETTA. If implementation of the Target Model does necessitate market splitting in Britain, it will materially alter the locational price signals conveyed to users through the energy market, and will alter the case for the use of either the WACM 2 or status quo methodologies.

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[86] Project TransmiT: Review of Ofgem Impact Assessment of Industry Proposals CMP213, NERA Economic Consulting and Imperial College London, Prepared for RWE npower, 9 October 2013, Section 6.2.

[87] Ofgem (April 2014), Appendix 2 para 1.32.

[88] CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014, page 83.

Given the possibility that market splitting will necessitate changes to the TNUoS methodology, and that the supposed benefits of WACM 2 in terms of savings in power sector costs arise late in the modelling horizon to 2030, there is a material risk that market splitting will erode any supposed benefits of WACM 2.

Ofgem has so far not considered this effect during the CMP213 consultation process. However, it is consulting separately on the possibility of market splitting. On 28 March 2012, Ofgem published an "open letter" on the EU Target Model and the need to consider market splitting to allow more efficient management of internal constraints:[89]

> "*An example of a binding requirement* [of the Target Model] *is a mandate on National Grid to propose, and Ofgem to consider, the merits of separate price zones to manage internal constraints in GB more efficiently. The idea is that electricity is exported (or imported) across interconnectors only when there is a real surplus (scarcity) of generation in the relevant portion of our network (zone) connected to a neighbouring country.*"*
>
> "**For example, if we implemented price zone delimination* (sic) *by splitting the GB market into Scotland and England & Wales, in case of congestion between Scotland and England & Wales, we would export to France only in case of surplus of generation in England and Wales.*"

Hence, the need to consider market splitting is clearly part of Ofgem's current work programme, and the possibility of market splitting materially undermines the long-term credibility of the WACM 2 charging methodology.

[89] Open letter: Implementing the European Electricity Target Model in Great Britain, Ofgem Letter, 28 March 2012.

5. Conclusions

5.1. Appraisal Against the Authority's Statutory Objectives

5.1.1. Consumer interest

The quantitative analysis commissioned by Ofgem from Baringa shows that consumers will face higher bills throughout the period to 2030 due to the introduction of WACM 2. This finding is in line with our own modelling, and conforms with economic theory regarding the likely impact of the proposed reform to TNUoS charges. Hence, the welfare modelling commissioned by Ofgem suggests that introducing WACM 2 runs contrary to its primary statutory objective, to protect the interests of current and future consumers.

However, Ofgem seems to ignore this evidence that consumers would be harmed by the introduction of WACM 2 for the following reasons, each of which is without merit:

- Ofgem considers that changes in power sector costs is a more accurate measure of likely consumer impacts, on the basis that higher prices/profits will attract new entry into the market. This argument is flawed, as the Baringa and NERA/Imperial modelling both account for the possibility of new entry driving down prices in response to higher profits caused by WACM 2. The result that higher prices (and higher average/total industry profits) emerge from the modelling is a very plausible result, emerging from the fundamental economic constraint that marginal new entrants into the power market must recover their costs, and WACM 2 leads to higher costs for the marginal new entrant (CCGT in southern GB in Baringa's modelling).
- Ofgem cites other non-monetised benefits that would result from WACM 2 setting more cost reflective charges, and thus improving the efficiency of market outcomes in ways that have not been modelled, such as reducing the cost of meeting longer-term renewables targets. However, Ofgem's reasoning is flawed, as it has failed to justify its belief that WACM 2 is more cost reflective than the status quo. It has not performed analysis to check whether WACM 2 tariffs are closer to or further from the cost that users impose on the transmission system than status quo tariffs, and our own analysis suggests that it will produce tariffs that are less cost reflective than the status quo methodology.

Moreover, we see a number of other factors that will result in consumers facing higher costs under WACM 2:

- WACM 2 will have material distributional effects, increasing the value of some generation assets and reducing the value of others. Regulatory decisions that redistribute value around the industry, especially when, like the proposed decision to implement WACM 2, they lack a robust justification grounded in evidence that the decision improves efficiency, increase the perception of regulatory risk, inflate financing costs, and thus increase consumer bills. Ofgem's latest consultation ignores this potential cost to consumers.
- To implement the EU Target Model, it may be necessary to split the British wholesale market into zones, delineated by points on the grid where persistent congestion arises. Pricing congestion through the energy market would signal the avoided cost of constraints for which TOs are required to provide transmission infrastructure, for example, by the "year round" and "economy criterion" provisions in the NETS SQSS. Hence, if market

splitting does occur, it will be necessary to revisit the decision to implement WACM 2, and the modelled reductions in power sector costs in the 2020s are unlikely ever to be realised. Moreover, investors' expectation that the WACM 2 methodology will not be sustainable will undermine the credibility of the locational signals it conveys to users.

5.1.2. Sustainable development

Ofgem has not identified any credible benefit from introducing WACM 2 from the perspective of promoting government environmental objectives. Some types of low carbon generators see higher charges under WACM 2, while some see lower charges. Overall, therefore, the impact of introducing WACM 2 on the costs of meeting renewable and low carbon targets is not clear-cut.

However, more cost reflective charging will support meeting low carbon targets efficiently (i.e. accounting for all power system costs that are ultimately born by consumers), so assessing which TNUoS methodology is most conducive to supporting sustainability objectives requires that the Authority identify which methodology is most cost reflective. As noted in this report and our previous reports, Ofgem has not demonstrated that WACM 2 is more cost reflective than status quo.

5.1.3. Non-discrimination

WACM 2 introduces components to TNUoS charges that result in different types of generator paying different charges, even if they are in the same location on the grid. Because Ofgem has failed to demonstrate that WACM 2 improves cost reflectivity, WACM 2 risks unduly discriminating between parties by levying TNUoS charges that differ across parties in a way not justified with reference to differences in the costs those parties impose on the transmission system.

5.1.4. Consistency with EU legislation

WACM 2 is an energy-based TNUoS charge, as by producing more energy today, generators tend to incur higher future TNUoS charges. Energy-based transmission infrastructure charges have the potential to distort trade with neighbouring markets, where generators do not face energy-based transmission infrastructure charges. Ofgem's consultation ignores the potential distortions to trade resulting from WACM 2.

5.2. Appraisal Against CUSC Objectives

5.2.1. Reflecting the costs incurred by the transmission operator

5.2.1.1. Ofgem's review of our cost reflectivity analysis

To promote efficient decision making by generators, the TNUoS charges faced by a user should reflect the costs of the infrastructure required to accommodate their presence on the grid. As Ofgem's consultation recognises, "*the costs that triggered by users should be paid for by those users*".[90]

As noted above, and despite the financial impact on generators of the proposed change in charging arrangements, Ofgem has failed to perform analysis to check whether WACM 2 tariffs are closer to or further from the transmission costs that users impose on the system. As described in our recent October 2013 and February 2014 reports, our own analysis suggests that WACM 2 will produce tariffs that are less cost reflective than the status quo methodology. Ofgem's commentary on this analysis indicates that it "*suggests that WACM 2 is actually more cost reflective than status quo"*.[91] However, Ofgem's assessment contains two key flaws:

- Ofgem's assessment of our LRMC modelling is based on the assertion that, because the marginal reinforcement of the England-Scotland boundary might not require HVDC, our analysis overstates "*the risks that WACM 2 may result in less cost reflective charges in certain circumstances*".[92] Our research suggests that most published studies on the future evolution of the British transmission system forecast increasing use of HVDC to reinforce these boundaries, including the Project TransmiT modelling on which Ofgem has relied. Hence, we can find no basis of evidence for Ofgem's statement that it uses to cast doubt on the assumption that the marginal reinforcement will require HVDC bootstraps. Moreover, Ofgem itself also presents no evidence on what alternatives to HVDC might be available.
- Ofgem asserts that our analysis shows that in the majority of cases, WACM 2 tariffs are closer to LRMC than status quo tariffs. First, Ofgem (and Baringa) give no justification for this conclusion. Second, this statement mis-represents our findings, and makes no assessment of which differences between tariffs and LRMC are largest and most likely to distort efficient decision making. Our assessment, which does consider these questions, reached the very clear conclusion that WACM 2 is likely to lead to less efficient locational decisions that the status quo.

Ofgem's criticisms of this analysis are therefore not valid. Despite the extended consultation period, our LRMC modelling still represents the only attempt to compare WACM 2 and status quo tariffs to LRMC, and thus test objectively the cost reflectivity of WACM 2. Our analysis shows WACM 2 performs less well than status quo at reflecting the cost that different types of users impose on the transmission system.

5.2.1.2. Reflecting the SQSS

The new SQSS contains a "dual background" approach to defining transmission planning standards, in which the transmission investment obligations placed on the TOs depend on a "demand security criterion" and an "economy criterion". The SQSS also contains a provision

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[90] Ofgem (April 2014), Appendix 2, para 1.65.

[91] Ofgem (April 2014), para 2.15.

[92] Ofgem (April 2014), para 2.20.

that more capacity should be provided by TOs than prescribed by these deterministic criteria, if it can be justified using a full CBA approach to transmission planning.

WACM 2 incorporates the same dual background as appears in the SQSS into TNUoS charging arrangements. It also defines some charge components as a function of ALFs and diversity factors, which Ofgem believes are related to the investment costs that would be prescribed by a full CBA framework. Therefore, Ofgem seems to believe that WACM 2 must necessarily be more cost reflective than status quo.[93]

This position is no more than a belief without foundation in analysis or tangible evidence, and the reasoning underpinning it is flawed. Superficially, WACM 2 does "reflect" the drivers of transmission in the new SQSS. However, the crucial problem with WACM 2 is the way and extent to which these factors are "reflected". Even if generators with higher ALF impose higher transmission costs on the system, it is not sufficient to conclude that a charging methodology in which charges are a simple increasing function of ALF necessarily reflects costs more closely that an alternative that does not include ALF in the formula.

In other words, whether a methodology in which charges are a function of ALF reflects costs more closely than an alternative methodology that does not use ALF depends on how the relationship between ALF and charges is *formulated*, and how any formulaic relationships are *parameterised*. Ofgem has not investigated whether either of these crucial aspects of the WACM 2 charging model produce cost reflective charges, or charges that are more cost reflective than status quo.

5.2.2. Facilitating competition

In general, we support the suggestion made by Ofgem in its original impact assessment that making charging models more cost reflective will tend to facilitate effective competition.[94] However, Ofgem is wrong to suggest that WACM 2 will facilitate competition, on the basis that there is no evidence that it is more cost reflective than the status quo.

5.2.3. Accounting for developments in transmission licensees' businesses

From our review of the Project TransmiT documents, the main "developments in transmission licensees' businesses" that Ofgem is seeking to reflect in new charging arrangements are: (1) the dual drivers of transmission investment, and (2) the presence of HVDC technologies on the transmission system. Both the status quo and WACM 2 give similar treatment to the HVDC bootstraps in the charging model, so presumably both accomplish the second aim.

Regarding the first development, status quo does not attempt to reflect the dual drivers of transmission investment whereas WACM 2 does. However, as noted above, the precise formula used to calculate tariffs under WACM 2 may or may not produce charges that are more cost reflective than status quo, even though the WACM 2 formula includes some

93 See, for example, Ofgem (April 2014), para 2.18.

94 Ofgem (August 2013), para 6.9

variables that are correlated with transmission investment requirements for reasons besides peak security (ALF, diversity factors, etc). In practice, our analysis suggests that WACM 2 produces tariffs that are further from LRMC for some categories of generation where investors have a range of locational options (in particular, wind farms). Hence, both charging models perform equally poorly against this criterion.

5.3. Summary

Ofgem's own quantitative analysis suggests that implementing WACM 2 would harm consumers. Ofgem has also failed to show that WACM 2 is more cost reflective than the status quo methodology. Hence, there are no reasonable grounds for Ofgem's minded to decision.

Appendix A. Options for Reinforcing the Scotland-England/Wales Transmission Boundaries

A.1. Ofgem's April 2014 Consultation Document

Ofgem's consultation document criticises some of the assumptions underlying NERA/Imperial's calculation of the LRMC of transmission costs.[95] Principally, it suggests that NERA and Imperial are wrong to assume the marginal addition to transmission capacity between England and Scotland will be High Voltage Direct Current (HVDC) "bootstraps".

> "*The NERA/ICL model assumes that the marginal reinforcement required on the network between Scotland and England is an HVDC bootstrap.*
>
> *We consider that the type of future investment to be uncertain. There is likely to be a broader range of investments than assumed by NERA/ICL in its modelling. Some of this investment will be at a cost lower than the cost of the equivalent existing network at current prices. We also consider that fewer HVDC links may be built than currently being considered which gives further weight to this argument. Under the Strategic Wider Works process put in place under the RIIO-T1 price control, TOs must demonstrate that its proposed investment is the most efficient option. This will not always be an HVDC link as other alternative investment options may deliver a better result.*"

This appendix reviews a range of studies that seek to forecast the evolution of the British transmission system. As described in more detail below, most studies either assume or predict new transmission capacity to reinforce the Scotland-England boundaries will be provided using additional HVDC bootstraps, beyond the western HVDC link, which we understand is already in development.

A.2. Baringa Modelling (2014)

As described in the body of this report, Ofgem commissioned Baringa to provide a quantitative analysis of the WACM 2 charging methodology.[96] As part of this analysis, Baringa lists the future investments that are scheduled to increase transmission capacity in Great Britain. Baringa's model appears to use Ofgem's list of future investment (i.e. the project pipeline shown in Figure A.2), and commission those that are needed in a particular model run. Baringa's model commissions HVDC reinforcement of the England-Scotland transmission boundary, as shown Figure A.1.

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95 Ofgem (April 2014), pages 14-16.

96 CMP213: further analysis and review of consultation responses, Baringa, 25 April 2014.

Figure A.1
HVDC Links Assumed By Baringa

Table 15 Timing of new HVDC links

Reinforcement	Capacity (MW)	Boundaries reinforced	Status Quo (Original)	WACM2 (Original)	Status Quo (Alternative)	WACM2 (Alternative)
Western HVDC Link	2000	B6, B7a	2016	2016	2016	2016
Western HVDC Link #2	2000	B6, B7a	-	-	2027	2026
Eastern HVDC Link	2000	B2, B4, B5, B6, B7a	-	-	-	-
Eastern HVDC Link #2	2000	B2, B4, B5, B6, B7a	2021	2021	2021	2021
Wylfa-Pembroke 2GW HVDC link	2000	B202, NW2	-	-	-	-
Caithness - Moray HVDC	600	B1	-	-	-	-
Humber - Walpole HVDC	2000	B8, B9, B11, B16	-	-	-	2030

Source: Redpoint (2014), page 58.

A.3. Strategic Wider Works Programme (2013)

The SWW Programme is the mechanism through which TOs can develop new network investment projects during the RIIO-T1 price control. TOs propose new investment to Ofgem, which assesses their proposals and alters their revenue allowance (subject to approving the investment).

As part of the SWW programme, Ofgem produced a non-exhaustive list of future transmission projects it believes might be brought forward by the TOs. The pipeline of projects includes the Eastern HVDC link (and a subsequent second link), as well as a 400kV East Coast link. The cost-benefit analysis for these (to the extent there is one) is in the ENSG report discussed in Section A.5.

Figure A.2
Prospective "Strategic Wider Works"

Transmission Owner	Proposed project	Key driver for investment
NGET	Hinkley-Seabank	Proposed new nuclear generation at Hinkley Point
NGET; SHE Transmission; SPTL (joint project)	Eastern subsea HVDC link	Increase in the north-south transfer capacity; new offshore generation in Firth of Forth
SHE Transmission	Caithness-Moray	Onshore and offshore renewable generation
SHE Transmission	400kV East Coast	Increase capability to export renewable energy to central Scotland and North England
SHE Transmission	Kintyre-Hunterston	Renewable generation around Kintyre, Argyll and Bute area
SHE Transmission	Western Isles link and onshore works	New generation on Lewis
SHE Transmission	Shetland HVDC link	Generation around Shetland
SHE Transmission	Orkney Isles link	Renewable generation around the Orkney Isles and Pentland Firth
SHE Transmission	Beauly-Mossford overhead line	Renewable generation projects in the Strathconon and Mossford areas
SHE Transmission	Second East Coast subsea HVDC link	Wind generation including Moray Firth and marine generation from Pentland Firth and the Orkney Waters
SPTL	Dumfries and Galloway	To facilitate renewables in SW Scotland and to provide a secure link to the Moyle interconnector
SPTL	East Coast (Kincardine – Harburn) 400kV	Enables increased levels of renewable energy to be transferred from SHETL to SPTL network areas.

Source: Ofgem.[97]

A.4. National Grid's Ten Year Statement (2013)

National Grid publishes an annual *Ten Year Statement*, which includes investment recommendations for reinforcing the boundary between England and Scotland (as shown in Figure A.3). National Grid's forecasts suggest that resolving the "*limitation on exporting power from Scotland to England*" requires further investment in HVDC: a second Western link, and up to three Eastern HVDC links.

[97] Ofgem (2013), *Strategic Wider Works (SWW) Factsheet*, November 2013.

Figure A.3
NG's Recommended Investment Includes Large Amounts of HVDC

Table 4.6
Scottish Investment Options

Driver	Potential transmission solution		
	Category	Option	EISD
Limitation on power transfer from generation in remote locations to the main transmission routes	Asset	Gravir on Lewis to Beauly HVDC Link	2018
		Shetland to Mainland HVDC Link	2018
		Orkney – Dounreay AC Subsea Connection	2018
		Beauly-Mossford 132kV Reinforcement	2015
		Beauly-Tomatin 275kV Reinforcement	2018
		Foyers-Knocknagael 275kV Upgrade	2015
		Lairg-Loch Buidhe 275kV Reinforcement	2019
		Skye 132kV Second Circuit	2021
		South West Scotland Connections Project	2015
		Kilmarnock South – Coylton 275kV Uprating	2016
		Coylton – Mark Hill 275kV Uprating	2016
		Kilmarnock South 400/275kV Substation Uprating	2018
		Dumfries and Galloway Reinforcement	2023
Limitation on exporting power from Argyll and the Kintyre peninsula	Asset	Kintyre to Hunterston Subsea Link	2015
Limitation on power transfer from north to south of Scotland	Asset	Beauly to Denny Reinforcement	2015
		Beauly – Blackhillock – Kintore Uprate	2015
		Caithness – Moray Reinforcement Strategy	2018
		East Coast 400kV Uprate Blackhillock to Kincardine	2018
		Tealing – Westfield – Longannet Uprate	2019
		Central 400kV Uprate	2019
Limitation on exporting power from Scotland to England	Asset	B6 Series and Shunt Compensation	2015
		Harker – Strathaven Reconductoring and Series Compensation	2019
		Western HVDC Link	2016
		Eastern HVDC One	2019
		Eastern HVDC Two	2021
		Eastern HVDC Three	2025

Source: National Grid.[98]

A.5. Electricity Network Strategy Group (2012)

The Electricity Networks Strategy Group (ENSG) is a body jointly chaired by DECC and Ofgem, with the aim of identifying and co-ordinating work to reinforce the transmission system. In 2009, it produced "vision for 2020", in which it identifies the likely future investments in transmission capacity.[99] It updated this report in 2012.[100]

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98 National Grid (2013), *Electricity Ten Year Statement*, page 159.

99 ENSG (2009), *Our Electricity Transmission Network: A Vision For 2020*, July 2009.

100 ENSG (2012), *Our Electricity Transmission Network: A Vision For 2020*, February 2012, page 70.

A.5.1. Assessment of the western HVDC "bootstrap"

The ENSG reported the results of a cost-benefit analysis (CBA) of a 2.1GW western HVDC link. First, the HVDC cable was found to provide greater net benefits than "doing nothing" and paying constraint costs. Second, the HVDC link was appraised against two alternative options, (1) installing two new 400kV transmission circuits (one from the East and one from the West of Scotland), and (2) reconductoring an existing 400kV double circuit. Neither of the options were superior, because:[101]

> "*They did not represent the most economic solution. The total length of the new circuits would be in excess of 600km; this resulted in a total project cost that was higher than the undersea HVDC option.*
>
> *For these reasons it was decided not to progress with onshore AC reinforcements*".

A.5.2. Assessment of the eastern HVDC "bootstrap"

The ENSG report foresees that the Western HVDC link will be sufficient to resolve transmission constraints on the England-Scotland border until 2018. Thereafter, further reinforcement is needed.

A CBA was performed to compare the effect of installing a 2.1GW Eastern HVDC link against doing nothing, and was found to be superior. The ENSG only briefly considered other options:[102]

> "*A number of alternative options are under consideration to increase the capability of the B4, B5, B6, B7 and B7a boundaries. These include onshore system reinforcement.*"

A.5.3. Project pipeline

Forecasts made in the ENSG report clearly suggests that they consider the most likely future investment (and presumably, therefore, the least cost investment) to be HVDC. These are shown in Figure A.4 to Figure A.6.

Between the 2009 and 2012 ENSG reports, a 400kV double circuit between Norton and Spennymoor was removed, and replaced it with the East Coast HVDC link,[103] suggesting that, if anything, alternatives to HVDC reinforcements are becoming less likely, and not more likely as Ofgem's April 2014 consultation suggests.[104]

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[101] ENSG (2012), page 70.

[102] ENSG (2012), page 72.

[103] ENSG (2012), page 76.

[104] Ofgem (April 2014), para 2.17.

Figure A.4
Reinforcement of the England-Scotland Transmission Boundary B6

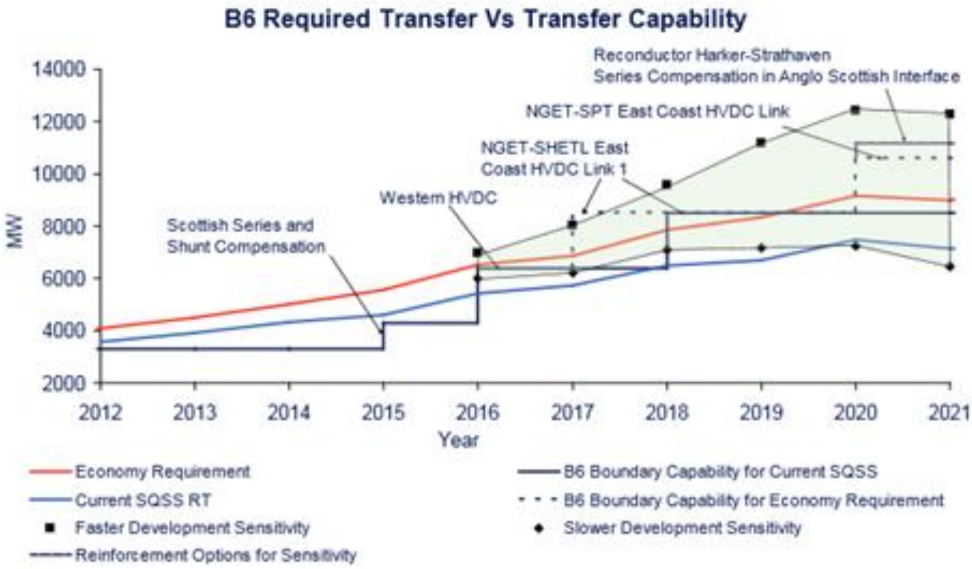


Figure A.5
Reinforcement of the England-Scotland Transmission Boundary B7

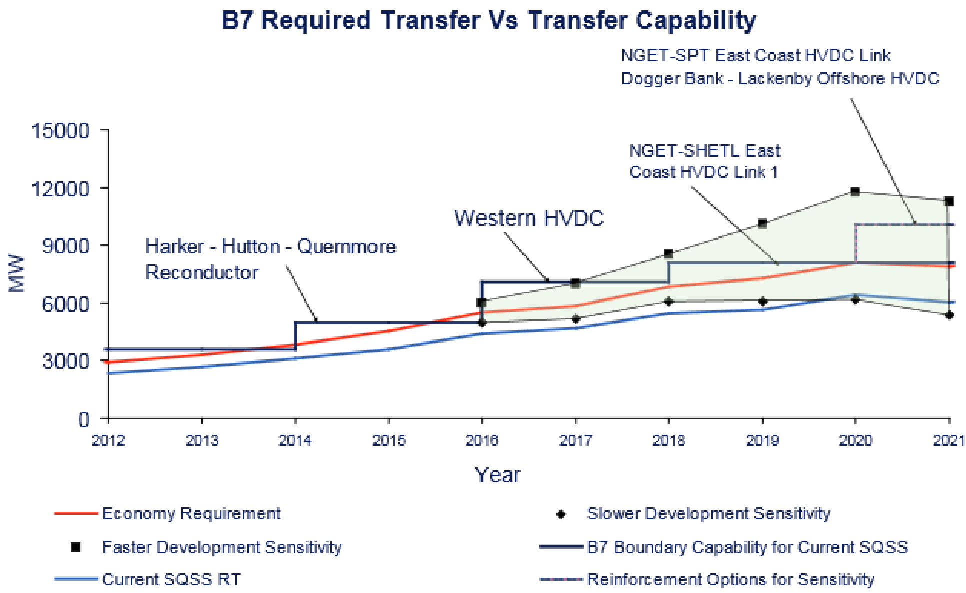
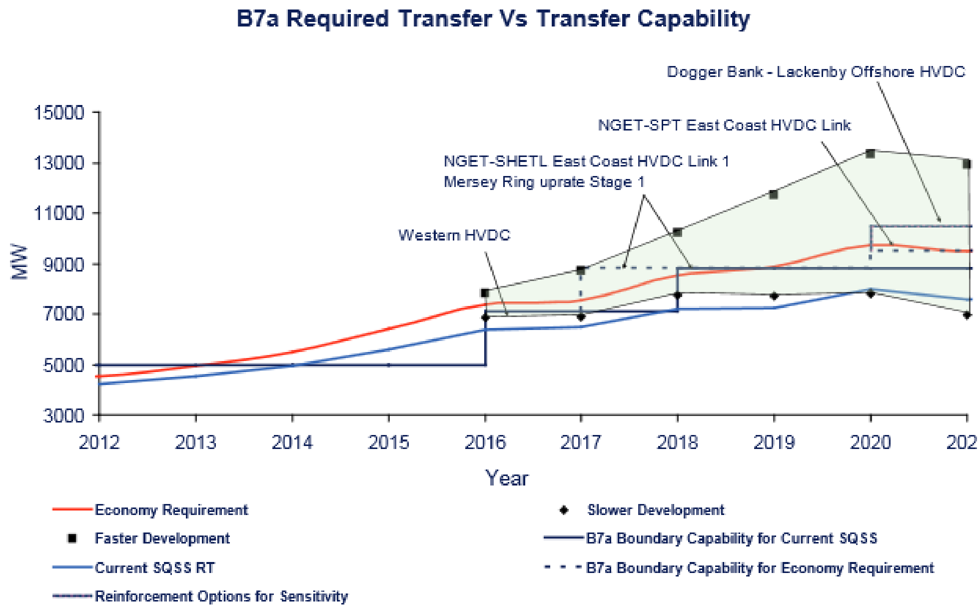


Figure A.6
Reinforcement of the England-Scotland Transmission Boundary B7a



A.6. Transmission Investment Incentive (2011 onwards)

Ofgem uses the TII mechanism to grant TSOs upward revisions to their revenue allowances if justified by large, one-off investment. The western HVDC "bootstrap" was funded through this mechanism. Documents published as part of the TII process discuss some of the costs and benefits of HVDC (although HVDC is assessed against a "do nothing" option, rather than any alternative transmission investment option).

A.6.1. SKM review of western "boostrap" (2011)

SKM were commissioned by Ofgem to review NGET and SPT's proposal for the western HVDC "bootstrap".[105] SKM is fairly critical of NGET/SPT's request for funding for the project, saying "*it appears that no full CBA of all the costs and benefits associated with both the Western link, Eastern link, other onshore reinforcements and constraints was conducted back in 2009, or has been conducted since*".[106] SKM recommended further work be carried out by the TSOs to justify their request for funding.

A.6.2. Poyry review of western "bootstrap" (2012)

Poyry were commissioned by Ofgem to review NGET and SPT's revised proposal for the western HVDC "bootstrap".[107] Poyry benchmarked the costs of a HVDC project. However, these results are redacted in the publically released report.

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[105] SKM (2012), *Independent Review of Funding Request for Western HVDC Link*, 1 August 2011.

[106] SKM (2012), page 53.

[107] Poyry (2012), *Western HVDC Final Funding Review – A report to Ofgem*, April 2012.

Appendix B. Critique of Baringa's Imperfect Foresight Modelling Approach

Our modelling approach assumes that generators take decisions regarding the timing, type and location of new entry (and exit) by comparing the revenues earned by each asset to the costs it incurs over the expected life of the asset. New investments will come online only if the expected net present value (NPV) of revenues exceeds the expected NPV of costs, where NPVs are calculated using a market-based discount rate specific to each generation technology.

Baringa characterises our modelling approach as one of "perfect foresight", suggesting that our approach implies investors have "full knowledge" of the conditions they will face in the future. Baringa then argues that the approach is not reflective of the uncertainty that investors face when making investment decisions:[108]

> *"When the iterations converge, the modelling approach represents a perfect foresight world in which decision making on generation and transmission investment is made with full knowledge of future tariffs and profitability. This approach does not reflect the imperfect view of the future that investors have to assess to when they make their decisions"*

In contract, Baringa's own modelling chooses investment decisions based on a five-year forecasting horizon, which assumes that investors ignore expected costs and revenues that occur further than five years into the future, and therefore base their decisions solely on the near-term market outlook.

B.1. Our Approach does not Assume "Perfect Foresight"

The term "perfect foresight" as used by Baringa suggests that NERA/ICL's iterative approach effectively produces *deterministic* outputs of tariffs and profitability, i.e. "full knowledge" of outcomes over the modelling horizon. This description implies that investment decisions are based on investors' expectations of tariffs and profitability that will be realized with *certainty*. As we discuss below, this interpretation offered by Baringa shows a misunderstanding of our approach, because it fails to acknowledge that our modelling of investment decisions *recognizes* and *accounts* for uncertainty of future outcomes.

In accordance with standard financial theory, our approach to choosing new generation capacity is based on assessing the Net Present Value (NPV) of each project under consideration, by comparing the *expected* revenues of the project with the *expected* costs of the project in present value terms over the economic life of the asset, i.e. after *allowing* for the inherent risks around the cost/revenue expectations. Standard corporate finance textbooks refer to this fundamental principle as "the Net Present Value Rule" (NPV Rule), based on

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[108] Redpoint, p. 22.

which investor should go ahead with the project if the project cashflows have a positive NPV.[109]

The NPV Rule is a simple mathematical expression of two fundamental principles that determine the value of investments in financial economics:[110]

1) ***Timing of casfhlows****:* This principle recognizes that "*a dollar today is worth more than a dollar tomorrow",* also known as "the time value of money" valuation component. In simple terms, this principle recognises that an investor considering purchasing/building an electricity generating asset today, with a view to receive an expected (albeit uncertain) income from electricity generation in the future, at the very least has the alternative option of investing that money in a risk-less asset, i.e. a government bond, which generates annual interest with certainty.[111] Following this principle, investors recognise that future cashflows are worth less at present, because they can be accrued in the future if some fraction (lower in value) today is invested at a compound interest rate to be accrued over a defined period in the future. To reflect this notion that present casfhlows have lower value to investors than future cashflows, future cashflows are "discounted", i.e. marked down based on a "discount rate" that is at least as large as the alternative interest investors can receive from investments in risk-less assets, with cashflows being discounted to a greater extent the further into the future they fall. We refer to this adjustment as the "time-value of money" adjustment.

2) ***Uncertainty of cashflows:*** A second fundamental principle in valuation is the notion that *"a safe dollar is worth more than a risky one".* This principle explicitly recognizes that investors *do not* have a perfect foresight of the future cashflows, because there is uncertainty around their expected revenues and costs. For example, generators considering purchasing/building an electricity generating asset today will have a view of the *expected* cashflows they will receive from generating electricity, based on their best forecasts of revenues and costs that reflect all presently available market information. However, since electricity prices (and many other costs, such as fuel prices etc.) are uncertain and hence there is risk associated with their outturn values, investors use an *appropriate discount rate* when marking down these future casfhlows, to reflect the risk associated with these cashflows. Standard finance textbooks define this appropriate discount rate as the ***hurdle rate*** or the ***opportunity cost of capital***, which is defined as the return on investments with the same risk as the given project which investors are foregoing because they are committing funds to the given project[112]. This return is therefore the *standard of profitability* that investors require in order to make the investment. By marking down future cashflows by this

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109 See for example Brealey & Myers, *Principles of Corporate Finance, 9th ed.* Chapter 2.

110 See Brealey & Myers, *Principles of Corporate Finance, 9th ed.* Chapter 2

111 We use government bonds as the best market proxy of the true risk –free rate, which is the yield on risk-less securities with certain payoffs. In practice, a country risk premium determines the extent to which investors' price in risk of government default, with country risk premium being greater for developing countries.

112 Common models used to estimate the required rate of return on equity by investors is the Capital Asset Pricing Model (CAPM), under which investors require compensation for bearing *systematic* (i.e. correlated) risk with the market.

rate of return, they are assessing the profitability of the project, *after* having accounted for the return they would require in order to bear the risk of this investment.

Figure B.1 illustrates how the NPV Rule would be applied by an investor in a long-lived energy infrastructure asset (e.g. t=20). In this illustrate example, we sketch the cashflows of a generic generation asset that has a large upfront capital expenditure when the asset is built in time t=0, and generates a steady real annual income stream over the next say 20 years (1 to t in Figure B.1, where t=20).[113] As described above, an investor evaluating the profitability of the project in time 0, would weigh the following items:

- The PV of the negative casfhlow in time 0 (shown by the red bar in Figure B.1), which is the same value as the current capital expenditure of the project, since this casfhlow is immediate and hence not discounted;[114]
- The PV of each future *expected* positive cashflow *over the expected life of the project* (a function of annual output, captured electricity prices, variable fuel and operating costs, the level of subsidies etc.), shown as the dark-shaded blue bars in Figure B.1. The PV of these future cashflows decreases over time, as more and more of the total expected annual cashflow (shown as the sum of the dark-shaded and light-shaded bars) are discounted (shown by the light-shaded blue bars in Figure B.1).

Thus, an investor evaluating the investment opportunity of this illustrative asset, would compare the negative capital outflow (red bar) with the sum of the positive expected inflows of cash (dark blue-bars) over the entire life of the project. If the PV of the positive casfhlows outweighs the negative casfhlow, then the NPV of this investment is positive, and an investor will undertake this investment opportunity.[115]

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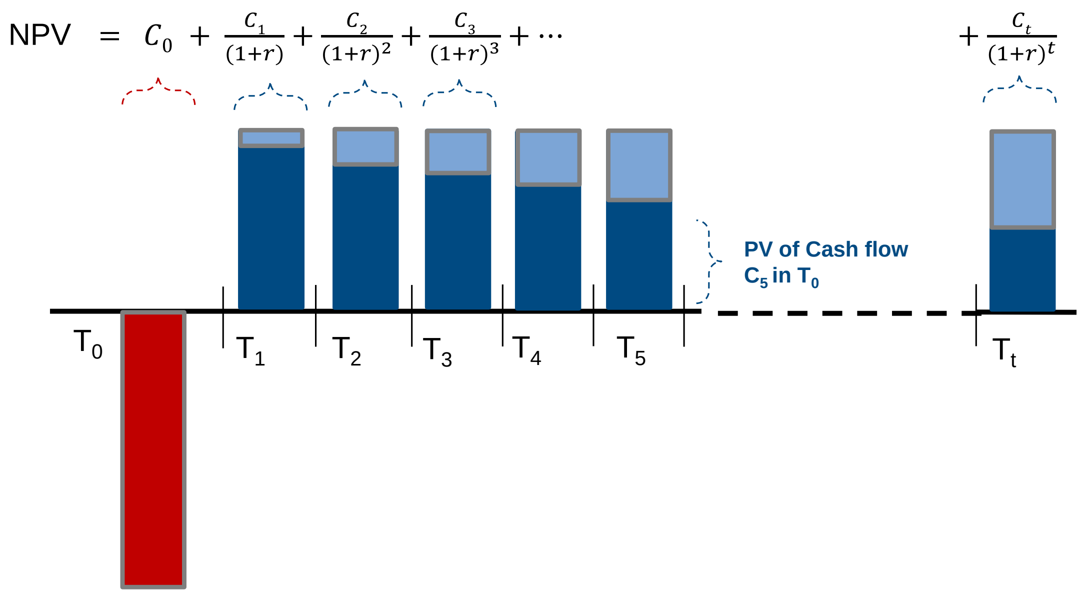
[113] Note for simplicity, we omit from this illustrative example other casfhlow items that would accrue to this asset in years 1 to 20, e.g. operating costs, subsidies etc. It should be understood that positive cashflows accruing in years 1 to 20 are in fact net cashflows accruing in each period. All principles described in this section apply to those net casfhlows.

[114] We assume any interest during construction is rolled into the upfront cost incurred by the developer.

[115] Note, the NPV Rule can be expressed equivalently as the "the Rate of Return Rule", under which investors should go ahead with a project if the offered rate of return is at least as large as the opportunity cost of their capital.

Figure B.1
Investment Decisions Under Uncertainty ("Net Present Value Rule")



***NPV > 0** → go ahead with project;* ***NPV < 0** → do not go ahead with project*

Our modelling approach reflects this simple yet powerful rule of making investment decisions:

1) Investors assess investment opportunities based on the available information at the time of making the decision, which is reflected in their *expectations* of future casfhlows. Our iterative process to choosing transmission and generation investments converges to a level which reflects the best *expectation* that investors would have of future outcomes (tariffs, profitability) based on all presently available information. These views are not assumed as certain, or deterministic, but rather are assumed to represent reasonable expectations of the most likely path of outcomes investors will face in the future.

2) Investors consider the present value of the entire expected cashflow stream o*ver the life of the project;*

3) In comparing the present value of cashflows to costs, investors account for uncertainty of the expected casfhlows by discounting them at the appropriate discount rate which reflects the riskiness of the investment (or their opportunity cost of capital). Our modelling *allows* for uncertainty by taking this standard approach to discounting cashflows when making investment decision.

B.2. The Lack of Theoretical Support for Baringa's Approach

As discussed above, the principle rule for making capital investment decisions is the NPV Rule, based on which investors decide whether to commit capital by assessing whether the NPV of the cashflows expected to accrue to an asset is positive or negative.[116] Equivalently, this same principle can be expressed in terms of the Rate of Return rule, under which investors accept projects if the expected rate of return is greater than the investors' opportunity cost of capital.

For long-lived assets, investors sometimes also use the "discounted cashflows (DCF) rate of return" also known as the "internal rate of return" (IRR) approach to valuation, which based on the same principles discussed above, solves for that discount rate which makes the net present value of the project's cashflow equal to zero. [117] Investors then compare this IRR with the cost of capital of the project, and only make a decision to invest if the former is greater than the latter.

Therefore, as can be seen from the above, standard valuation techniques rest on the idea that in making investment decisions investors take into account ***all*** future positive or negative cashflows accruing to the project over its entire economic life.

Baringa's own modelling choice shows misunderstanding of these fundamental financial principles. Rather than looking at the entire modelling horizon, Baringa calculates the profitability over the first five years of the life of the asset. This assumption is unrealistic and has no basis in financial theory. As we showed above, valuation exercises include *all expected* cashflows over the life of the asset, which are assessed against a standard of profitability, i.e. discounted at the investors' appropriate cost of capital (see above). Any known/expected cashflow that has a positive or negative present value after the appropriate discount rate has been applied, *affects* the investment decision of rational investors, because it determines whether the investor is anticipated to cover its capital and maintenance outlays over the life of the project, including earning an appropriate rate of return on this investment for accepting to bear the risks associated with it.

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116 See for example, Chapter 3 & 5 and 6 of Brealey & Myers, *Principles of Corporate Finance, 9th ed* . For example, in section 6.1 *Review of the Basics*, the authors give the following example of how to appropriately answer the question of "how to analyse a proposed $1million investment in a new venture called project X": "First, forecast the cash flows generated by project X *over its economic life*. Second, determine the appropriate opportunity cost of capital. This should reflect both the time value of money and the risk involved in project X. Third, use this opportunity cost of capital to discount the projects' future cash flows. The sum of the discounted cash flows is called present value (PV). Fourth, calculate the net present value (NPV) by subtracting the 11million investment from PV. Invest in project X if its NPV is greater than zero."

117 The Internal rate of return of a project is calculated by setting up the same NPV calculation of cashflows as is done when taking an NPV approach, but *solving* for that rate of return which would make the NPV of casfhlows equal to zero, in the following equation:

$$\text{NPV} = C_0 + \frac{C_1}{(1+IRR)} + \frac{C_2}{(1+IRR)^2} + \frac{C_3}{(1+IRR)^3} + \cdots + \frac{C_t}{(1+IRR)^t} = 0$$

Investment decision are then taken if the IRR of a project is greater than or equal to the opportunity cost of capital of the project. See Brealey & Myers, *Principles of Corporate Finance, 9th ed,* Chapter 6.

B.3. Conclusions

In this section, we summarised why Baringa misrepresents our approach as assuming investors have “perfect foresight”. Our approach accounts for future uncertainty, by appropriately discounting the *expected* cashflows investors anticipate receiving over the life of the asset, as is standard in financial theory and the practical evaluation of investment opportunities, such as the option to build transmission or generation assets. In contrast, Baringa’s own approach is inconsistent with financial theory, because it ignores known or anticipated changes to casfhlows/margins over the modelling horizon, and can lead to suboptimal investment decisions.

Appendix C. Recent Developments to Low Carbon Subsidy Arrangements

Since the end of 2010 the Department for Energy and Climate Change (DECC) has managed a period of policy change in the UK electricity market, under the program of Electricity Market Reform (EMR). One of the headline policy amendments has been to change the mechanism by which renewable electricity generators receive support from the government on top of the existing support provided through the wholesale market. The primary objective of current government policy on renewable electricity is to help achieve the UK's 2020 target to source 15% of all energy consumption from renewables. In order to achieve this, DECC expects that a 30% renewables share of power generation is required in 2020.[118]

C.1. Change in Renewables Support Scheme

To date, UK renewable project developers have applied for support under the Renewables Obligation (RO) scheme, established in 2002. This is a market based support mechanism in which qualifying renewable generators receive certificates (ROCs) for each unit of output exported to the grid. These certificates can then be sold to electricity suppliers, often along with the power that is generated, who are required to surrender a determined number of certificates each year, in proportion to the total electricity they supply.

Pursuant to the Energy Act 2013, DECC has introduced a Contract for Difference (CfD) Feed-in Tariff (FIT) support scheme which provides a top-up payment to generators in addition to their revenues from the sale of electricity. This top-up is provided up to a contractually determined level, known as the strike price, which will be agreed with each project developer prior to commissioning and will provide support for a maximum of 15 years.

After the CfD scheme opens, DECC intends to offer support to new capacity under either scheme until 31 March 2017, allowing project developers to choose their preferred subsidy regime.[119] From April 2017 all new capacity will then be required to apply for CfD FIT support, completing the transition from the RO to the CfD system for new capacity.[120]

C.2. Allocation of Contracts for Difference

In order to initiate the CfD scheme, DECC began a process in March 2013 to help renewable developers make firm investment decisions ahead of the enduring regime going live. This process, known as the Final Investment Decision Enabling for Renewables (FIDER), has selected five wind and three biomass projects for development and agreed contracts for their

[118] See, for example: DECC. Renewable Energy Roadmap. November 2011.

[119] Note that in practice CfD contracts are unlikely to be available prior to the first quarter of 2015 at the earliest. DECC also recently announced plans to restrict access for solar PV plants to RO support.

[120] Existing capacity supported under the RO will continue to receive support under this scheme.

support.[121] These projects will receive support at the level of the maximum strike prices published in December 2013 by DECC.[122]

Various details of the enduring CfD regime are still to be clarified and certain features are currently under consultation, pending a final decision. DECC is expected to award contracts to applicants on an annual basis, starting in the final quarter of 2014. The allocation of contracts will be constrained by the budget available to support renewable investments. This is set out in the Levy Control Framework, which places a cap on total spending in each year on levy funded schemes, currently covering small-scale FIT payments, the Warm Home Discount and RO and CfD FIT payments; the latter making up the most significant share of the total budget.

Given an available budget trajectory DECC has proposed that renewable technologies will be divided into two groups – *established* and *less established* technologies - with separate budget pots for each group. The established technologies, which include biomass, onshore wind and solar PV, will be subject to competitive allocation with contracts awarded via an auction process in which projects bid in the strike price that they are willing to accept and receive the auction clearing price, determined for each commissioning year. Initially DECC does not expect the projects applying within the less established group, namely offshore wind, to exceed the available budget, but in time DECC also intends to introduce competition to this group as well.

DECC has not released information on the relative size of the available budget that will be allocated to the different technology groupings. This will be set out prior to each allocation round.[123] DECC therefore allows itself a significant degree of flexibility to control how much of each technology is awarded a CfD contract.

C.3. Implications for Modelling the Impact of Changes in TNUoS

At the time of writing there remains a degree of uncertainty regarding the operation of the enduring CfD FIT regime, specifically with respect to the allocation of funds across the range of renewable technologies. However, it is clear that, while DECC retains discretion under the CfD FIT scheme to specify how much of the available support budget will be allocated to each of the onshore and offshore wind categories, it has not published details on how it will determine these limits. In particular, DECC retains control over which technologies receive support, and a key consideration in setting these support levels for (or allocating the support budget to) each technology, government will consider its desire to meet the renewables targets at least cost.[124]

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[121] The award of investment contracts was formerly announced by DECC on 23 April 2014.

[122] DECC. Investing in renewable technologies – CfD contract terms ansd strike prices. December 2013.

[123] For the first allocation round, due to take place in 2014, DECC intends to publish the final budget in September 2014, with the first auction expected in October 2014. (DECC. Electricity Market Refore: allocation of Contracts for Difference. Consultation on Competitive Allocation. January 2013; and subsequent government response on competitive allocation (May 2014).

[124] DECC has stated that the "Government will set budget allocations that it considers best meets its policy objectives including achieving the renewables target, keeping consumers costs low, the total costs within the LCF and achieving

Moreover, whilst DECC proposals do not explicitly set out direct competition between onshore and offshore wind projects (as they have been allocated to the separate ‘established’ and ‘less established’ technology groupings, respectively) by retaining control of the share of the budget to be allocated to each technology group we expect there to remain implicit competition amongst all wind project types in the long-run.

Changes in TNUoS may therefore affect the relative costs of different renewable technologies, and government has considerable scope to change renewables support payments and budgets in response to changes in cost. We therefore see no basis for Baringa’s assumption that there will be a fixed breakdown of capacity between onshore and offshore wind, as described in Section 3.2.2.3 of the main report.

value for money.” (DECC. Electricity Market Reform: Allocation of Contracts for Difference – A Government response on Competitive Allocation. May 2014)

Appendix D. Statistical Analysis of Wind Load Factor Data

In this appendix we analyse the Ofgem E-Serve database to derive the distribution of load factors achieved by wind generators in England, Wales and Scotland.

D.1. The Ofgem E-Serve Database

We downloaded data from the Ofgem E-Serve database for the years 2011-2013.[125] The database records the number Renewable Obligation Certificates (ROCs) awarded to renewable electricity generators each month. The database records how may ROCs are issued by MWh of generation at each site (different technologies are in different "bands", which have been revised over time).

The database includes generators that did not receive ROC certificates in every month from 2011-2013. We excluded these generators to avoid biasing the results because, for example, they only operated in particularly windy periods. We were left with a sample of 105 wind generators located in England (approximately 3.2 GW), 22 wind generators located in Wales (approximately 0.5 GW) and 87 wind generators located in Scotland (approximately 2.4 GW).

D.2. Average Load Factors by Region

For each of the 214 generators identified above, we calculated monthly load factors from the data on installed capacity and electrical output. We took the average load factor over the three year period and the standard deviation as a measure of the dispersion of load factors at different sites. These results, aggregate by region, are presented in Table D.1.

Table D.1
Load Factors (2011 - 2013) At Generators Across Great Britain

	England	Scotland	Wales	England & Wales
Mean	24.6%	28.4%	25.6%	25.0%
Std. Dev.	6.7%	8.7%	6.1%	6.6%
n	105	87	22	127

Source: NERA analysis of Ofgem data.

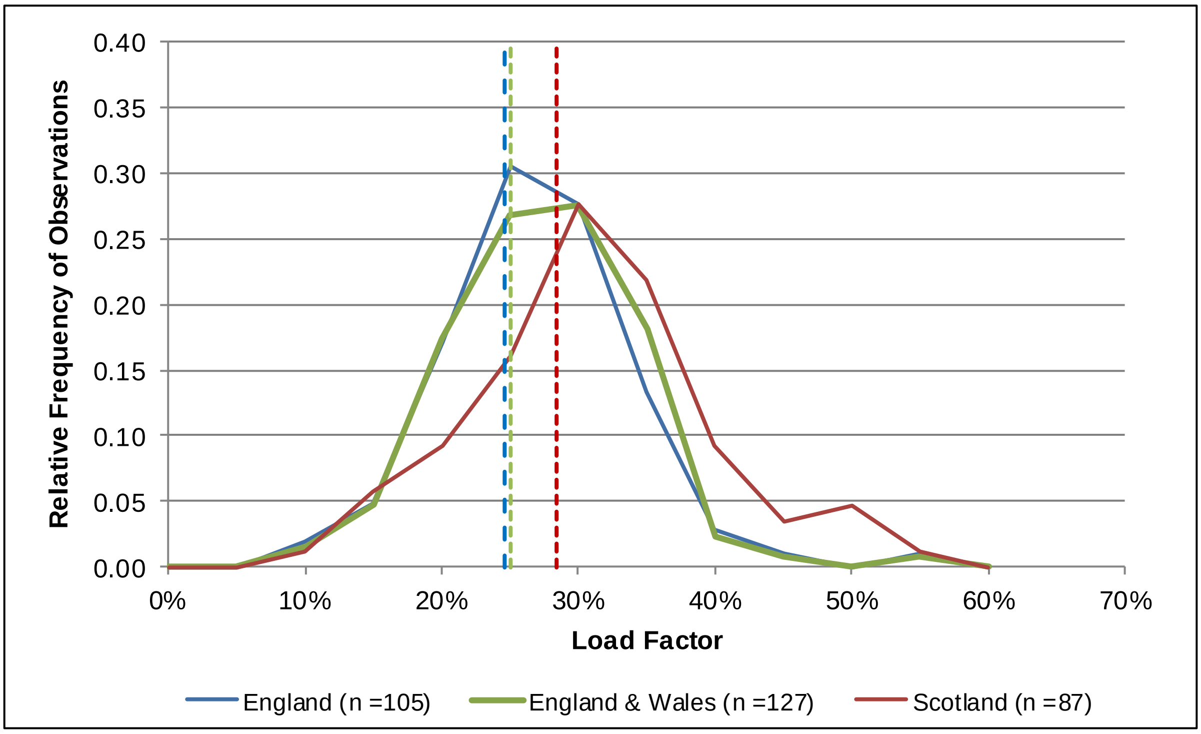
To represent the dispersion of load factors at generators across Great Britain, we examined the distribution of the data. Figure D.1 presents these distributions graphically, where the horizontal axis represents load factor and the vertical axis represents the relative frequency with which it was observed in our sample. The dotted lines represent the average for each area (England, England and Wales, and Scotland).

Figure D.1 suggests there is significant overlap between the distributions of wind load factors for each region. That is, while wind farms in Scotland have higher load factors on average

125 https://www.renewablesandchp.ofgem.gov.uk/Public/ReportManager.aspx?ReportVisibility=1&ReportCategory=0

than those in England and Wales, there are many wind farms in England and Wales that achieve relatively higher load factors too.

Figure D.1
Distributions of Load Factors at Wind Sites Across Britain



Source: NERA analysis of Ofgem data.

D.3. Distribution of Load Factors by Region

From Figure D.1, we can conclude that there is a significant probability that a randomly selected location in England (or England and Wales) will have a higher wind load factor than a randomly selected location in Scotland. To demonstrate this, we drew a generator at random from our sample of English generators and compared its load factor to a generator drawn at random from our sample of Scottish generators. We repeated this procedure several thousand times (a "Monte Carlo" simulation). Our results, presented in Table D.2, suggest there is roughly a 35 percent chance a site in England will exhibit a higher load factor than one in Scotland (and roughly a 37 percent chance a site in England or Wales will do the same). We also performed the same analysis "parametrically", i.e. by assuming that the distribution of wind factors is normal, and calculated the probability analytically. This confirmed our results.

Table D.2
There Are A Significant Number Of Sites With Higher Load Factors Than Scotland

	England > Scotland	England & Wales > Scotland
Probability (Monte Carlo)	35.0%	36.8%
Probability (Parametric)	35.7%	36.9%

Source: NERA analysis of Ofgem data.

We therefore conclude that there is significant diversity in the distribution of wind factors both across Great Britain and within each region. While wind load factors are highest on average in Scotland, both England and Wales have generators located at sites with higher load factors than the load factors achieved at many Scottish sites.

It is therefore incorrect to suggest that all Scottish wind farms have higher load factors than all English and Welsh wind farms, as Baringa's modelling assumes.

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NERA

ECONOMIC CONSULTING

NERA Economic Consulting
15 Stratford Place
London W1C 1BE
United Kingdom
Tel: 44 20 7659 8500 Fax: 44 20 7659 8501
www.nera.com