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Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology

Consultation

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Overview:

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

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

Project TransmiT identified defects in the current charging methodology. This triggered an industry led process to further develop the charging methodology to address the defects. The industry led process developed several options to resolve the defects. This document assesses the impact and sets out our initial analysis of the options and our minded-to position. We seek stakeholders' views on these.

Following the consultation and our consideration of responses, we plan to publish a final decision towards the end of the year.

Context

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

Against this background, we launched Project TransmiT to consider if any changes may be required to the electricity transmission charging arrangements. In May 2012 we directed National Grid Electricity Transmission (NGET) to initiate an industry led process to further develop the charging methodology to address the defects that we had identified.

This consultation considers the impact of all options presented to Ofgem for decision and requests stakeholders' views on our minded-to position.

Associated documents

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

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

Project TransmiT: Electricity transmission charging arrangements Significant Code Review conclusions, May 2012
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=232&refer=Networks/Trans/PT

Direction to National Grid Electricity Transmission plc in relation to the Significant Code Review under Project TransmiT
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=234&refer=Networks/Trans/PT

Other relevant documents are available on the Project TransmiT section of our website (including our web forum)
http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx

Documents published as part of the CUSC modification process are available on National Grid's website
http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

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Executive Summary

Transmission charges seek to recover the costs of developing and operating the transmission system. The current electricity transmission charging regime has served consumers well by promoting the efficient use and development of the network. This has helped to avoid unnecessary costs to consumers. However, the mix of electricity generation is changing rapidly, with more renewable and low carbon generators connecting to the network. It is therefore important that we review the methodology for calculating electricity transmission charges to make sure it remains fit for purpose.

Following our review of the transmission charging arrangements under Project TransmiT we instructed industry to develop proposals that would address the following three defects that we identified in the current approach:

- It does not appropriately **reflect the costs imposed by different types of generators** (in particular renewable generators) on the electricity transmission network. This is because it has not evolved to better reflect the changing generation mix and the different impact that users have on transmission investment decisions.
- It does not **reflect the development of High Voltage Direct Current (HVDC) links** that will run parallel to the onshore network. The first HVDC links is due to be commissioned in 2016 hence a modification needs to be in place by then.
- It does not **take into account potential development of Island links** which use subsea cable technology which are currently not catered for in the methodology.

Industry developed a number of different solutions to address these defects and has submitted these to us to decide whether to approve one of the options. We have assessed these options and have reached a **minded-to position to approve the option known as "Workgroup Alternative Connection and Use of System Code (CUSC) Modification 2"** (or WACM 2) in the industry submission to us.

This approach recognises that there are two drivers of transmission investment, namely the capacity required to ensure that the network is secure at times of peak demand, "Peak Security", and the capacity required for the efficient management of constraint costs, "Year Round" considerations. WACM 2 recognises these drivers and the ways that different generators have different impacts on transmission costs by:

- Splitting the tariff into a Peak Security component (which only non-intermittent generators, such as gas plants, would pay) and a Year Round component (which all generators would pay). We consider this aligns with the assumptions in the transmission planning standard[1] and therefore the drivers of transmission investment.
- Recognising that different generators drive different constraint costs and therefore trigger different levels of transmission investment for Year Round considerations. WACM 2 does this by using a generator's load factor (a measure of how much a plant generates) as a proxy for its impacts on constraints and hence transmission investment.

[1] The National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS)

- Acknowledging that areas with high concentrations of low carbon generation are less able to efficiently share transmission capacity. This is because low carbon generators are more expensive to constrain off (due to interactions with government renewable energy support policies) and are more likely to generate at the same time. Therefore it is efficient to build more transmission capacity for such areas.

We consider this to be a significant improvement to the existing approach which only recognises peak security as a driver of transmission investment and assumes that all types of generators contribute equally to it.

Our favoured option also incorporates solutions to charging for HVDC and Island links. In doing so it does not seek to socialise any of the associated converter station costs. We think this is appropriate given that we have not identified a strong reason to avoid targeting the recovery of these costs on the users of the links.

This proposal will impact generation by narrowing the divergence of generation tariffs between north and south of the country. Tariffs in the north will decrease whilst tariffs in the south will increase relative to the Status Quo. For example, indicative industry modelling suggests that in 2014 wind generators in the North of Scotland may pay on average £13/kW less than under the current method for access to the main transmission network and those in South West of England (Wessex charging zone) may pay £5/kW more.

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. This outweighs a much lower impact in the period up to 2020 where consumer bills could on average be up to £1.60 per annum higher than under the current methodology. This reflects the difference between short term impacts on generators' decision making and longer term impacts where we would expect the new methodology to result in more efficient decisions on the location of generation.

We consider that our preferred option will also promote sustainable development goals. We consider that it appropriately takes into account the impact of renewable generators on transmission costs and therefore does not represent an undue barrier to the deployment of renewable generation across Great Britain.

We have also considered the implementation date of our preferred option. We are **minded to approve implementation in April 2014** rather than at a later date. This is the earliest opportunity from which the methodology can take effect and will ensure the benefits of an improved methodology are realised sooner and that the defects in the methodology are addressed as soon as possible. We have not identified a strong reason to delay implementation beyond this date.

Overall, our minded to position is to approve Workgroup Alternative CUSC Modification 2 for implementation in April 2014. Based on the evidence presented to us and the analysis we have undertaken we think this option is consistent with our statutory duties and best meets our principal objective to protect consumers compared to other options submitted to us and the existing methodology.

1. Introduction

Chapter Summary

This chapter provides an overview of the current electricity transmission charging framework and sets out the structure of the rest of the document. There are no consultation questions on this chapter.

Overview

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

1.2. This document consults on the proposals submitted to us by industry as part of the Connection and Use of System Code (CUSC) modification proposal 213 (CMP213). It also sets out our impact assessment as required by section 5A of the Utilities Act.

The role and importance of transmission charging

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

1.4. TNUoS charges pay for the installation, reinforcement, maintenance and renewal of shared transmission assets that facilitate access to and the flow of power across the network. These assets cannot be solely attributed to a single user.

1.5. National Grid Electricity Transmission plc (NGET) is responsible, in conjunction with other stakeholders as appropriate[2], for ensuring that appropriate electricity transmission charging arrangements are in place. Ofgem's role is to set out the principles that NGET must adopt in carrying out this role and provide support and challenge as necessary to achieve this. This includes deciding whether proposals for modifications to the charging methodology developed by NGET and industry should be implemented.

1.6. The current transmission charging methodologies have applied across Great Britain (GB) since the introduction of the single electricity market through the British Electricity Trading and Transmission Arrangements (BETTA) on 1 April 2005. BETTA extended the existing charging regime for England and Wales to include Scotland.

[2] NGET has transmission licence obligations to have transmission charging methodologies in place, to keep its methodologies under review at all times and to make proposals to modify those methodologies where it considers a modification would better achieve the relevant objectives. The process for modifying the methodologies is contained within the Connection and Use of System Code (CUSC).

However, the principle of cost reflective charging has been a feature of the Use of System charging approach in England and Wales since 1990.

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

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

1.9. Locational signals should therefore allow participants to make efficient commercial decisions about where to locate new generation and when to close existing generation, thereby assisting in the development of an economically efficient transmission system. This in turn facilitates the efficient development of the GB electricity sector which can benefit consumers in the form of lower bills.

1.10. The current transmission charging regime has served consumers well by promoting the efficient use of the networks and facilitating effective competition in generation and supply. However, the mix of electricity generators is changing. In particular, there are an increasing number of variable generators, such as wind, wanting to connect to the system. The time is therefore right for us to consider whether the arrangements are fit to meet the challenges of the future and consider whether the proposals from industry that are assessed in this document better meet our objectives and these challenges.

Structure of this document

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

- Chapter 2 describes the background to this assessment
- Chapter 3 sets out the charging proposal raised by NGET and Working Group Alternative CUSC Modification (WACM) proposals developed by industry
- Chapter 4 sets out NGET's modelling approach which underpins the quantitative analysis that we present and the quantitative impact of the different charging options based on the modelling undertaken
- Chapter 5 sets out additional strategic and sustainability considerations
- Chapter 6 contains our assessment of the NGET Original and WACM proposals against the decision making criteria and sets out our minded-to position
- Chapter 7 sets out our next steps.

2. Background

Chapter Summary

This chapter provides background to this consultation, identifying its purpose and context. There are no consultation questions on this chapter.

2.1. This chapter sets out:

- a brief summary of how the TransmiT review has evolved;
- a summary of the assessment presented in our significant code review (SCR); and
- a brief summary of the industry process.

Evolution of Project TransmiT

2.2. Project TransmiT was launched in September 2010 and we provide a summary below of the progress so far:

- TransmiT was launched in September 2010 with a call for evidence. At its outset, the project focused on charging and connection arrangements for both gas and electricity transmission.
- Following this, in January 2011, we decided to focus TransmiT on connection issues and transmission charging issues for electricity transmission as this is where we identified the most material issues that required further investigation. In particular, this was so that these arrangements did not present a barrier to the UK meeting its environmental targets.
- In our May 2011 consultation we explained that options which would require more fundamental change to the electricity transmission charging and wholesale market arrangements, such as locational marginal pricing, would not be included within the scope of Project TransmiT[3]. We also consulted on our proposal to launch a SCR to focus on potential short-term changes to the current TNUoS arrangements as this was where stakeholder feedback suggested that the most significant concerns lay.
- In July 2011 we launched a SCR to examine electricity Transmission Network Use of System charging arrangements. There was broad consensus from industry in support of our decision to exclude options that would require more fundamental changes beyond the TNUoS arrangements.
- We concluded our SCR in May 2012 and directed NGET to raise a CUSC modification proposal to address the defects in the current methodology that

[3] The exact form of these wider changes and the scale of their impact on transmission charging in GB was, and remains, uncertain. We also sought to make any justified changes in a timely way, so as to realise any benefits to existing and future consumers as soon as possible.

we had identified. The SCR conclusions and direction to NGET are discussed in more detail below.

- NGET raised a modification proposal (CMP213) to address these defects in June 2012. This initiated an industry process to develop and assess solutions to the identified defects.
- Industry concluded its process in June 2013 when it submitted its proposals to us.

2.3. We are now at the final stage of the process where we must assess the proposals developed by industry and make a decision on whether to accept one of the options presented to us or whether to reject all of them.

2.4. We provide further details below on the SCR, the defects referred to in our direction, and the industry CUSC process.

Summary of the findings from our Significant Code Review

2.5. The consultative process that led to us raising the SCR identified a spectrum of potential options to change the current TNUoS arrangements. The range of options reflected the divergent views on the importance of cost reflectivity and about the ability of the current arrangements to help deliver a balanced, sustainable and diverse generation mix cost effectively for consumers.

2.6. The SCR sought to assess a suitable range of potential changes to TNUoS charging that could be implemented in the near term. The SCR considered three main options:

- The Status Quo (based on the principle of ICRP): retaining the existing Use of System charging methodology used in the calculation of TNUoS charges for generators and demand users.
- Improved ICRP: incrementally changing the current charging approach to improve the accuracy of cost targeting for generation charges by taking into account the fact that differences in the characteristics of generation drive different investment costs on the transmission network.
- Socialisation: recovering transmission costs through a uniform £/MWh tariff applied to all generation users, whatever their type and location.

2.7. We assessed these options against the three broad aims of the project: (i) deployment of low carbon generation across GB and impact on achieving the UK government's Renewable Energy Strategy target of 30% of generation from renewable sources by 2020 and carbon intensity goals in 2030, (ii) quality and security of supply across GB, and (iii) overall cost of the system as a whole and customer bill impacts. We also considered aspects of wider sustainable development as well as distributional impacts and a number of practical issues. Our assessment of these options was informed by our December 2011 consultation, and modelling of the impacts of different options by Redpoint Energy[4].

[4] Now Baringa Partners.

2.8. In May 2012 we concluded that we should not progress socialised charging as an option for transmission charging and that an improved form of ICRP is the best way forward because:

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

2.9. We therefore directed NGET to raise a modification proposal to the TNUoS methodology so that:

- it better reflects the differing impacts (ie costs and benefits) of individual generators on the TOs' costs in a manner which is consistent with the principles set out in the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS);
- it takes account of the development of High Voltage Direct Current (HVDC) links that will run parallel to the onshore AC network; and
- it appropriately takes into account the potential Island links that are currently being considered.

2.10. These are discussed in more detail below.

- **Better reflects the costs imposed by different types of generators** (in particular renewable generators) on the electricity transmission network. This is to ensure that the charging methodology better reflects the transmission investment framework set out in the NETS SQSS.

  The current charging methodology only recognises peak security as a driver of network investment and assumes that all types of generation within an area of the network (a generation charging zone[5]) contribute equally to investment for this purpose. In doing so it overlooks the fact that some investment is driven more by "Year Round (YR)" considerations (ie the seeking of an efficient balance between constraint costs[6] and transmission capacity to minimise overall costs) than the needs of peak security. Under the current methodology all types of generators within a zone receive the same tariff (ie are assumed to drive the same level of investment) – this does not recognise that: a) some plant are not assumed to provide peak security under the NETS SQSS; and b) different types of plant trigger different levels of constraint costs (eg depending on how much they use the system) and

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[5] Given the requirement for stable cost messages and administrative simplicity, the Methodology groups individual nodes into generation and demand zones and a zonal average tariff is calculated.
[6] A constraint on the transmission system refers to the situation where there is not enough physical network in place to either meet local demand or to transmit the power supplied on to the system and transport it to other parts of the network where the demand for that power is situated. In the event of an "Export" constraint, the System Operator will take actions to reduce the transfer out of an area to ensure that the boundary capability is not exceeded, by reducing generation or increasing local demand. Circumstances where generation within the local group needs to be increased, or demand reduced, are termed "Import" constraints. These actions incur constraint costs which are recovered through the Balancing Services Use of System charges from all users of the system.

therefore drive different levels of transmission investment for year round considerations.

- **Takes account of the development of HVDC links that will run parallel to the onshore network**. These are currently not catered for in the charging methodology. The first link of this kind (the Western Bootstrap) is due to be commissioned in 2016, so a methodology needs to be put in place before then.
- Appropriately **takes into account the development of potential Scottish Island links** that are currently being considered. These are currently not catered for in the charging methodology. The methodology needs to be developed so that charges can be calculated for users of these links and so that they can make appropriate investment decisions.

The industry process

2.11. In June 2012 NGET raised a formal modification proposal in accordance with our direction. This initiated an industry led process to develop and consider options to improve the current ICRP transmission charging methodology via the CMP213 Workgroup[7]. The Workgroup developed a number of options (27, including the NGET Original Proposal and 26 alternatives) to address the defects identified.

2.12. At the 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. This formed the Panel's recommendation to Ofgem. On 14 June 2013 the CUSC Panel submitted its final modification report to Ofgem for our consideration.

[7] The Workgroup was comprised of a number of industry specialists from a broad range of users.

3. The charging options developed by industry

Chapter Summary

This chapter sets out the options for change that have been presented to Ofgem for decision. It focuses on the solutions that have been developed in each of the three areas specified by our direction. There are no consultation questions on this chapter.

Overview

3.1. Following the SCR, we directed NGET to raise a modification proposal and the industry group proposed alternatives resulting in a total of 27 different proposals to address the defects in the charging methodology. This chapter provides a summary of how these proposals seek to address the defects of the current methodology discussed in the previous chapter. The different proposals to address each of these defects can be combined in different ways which is why 27 different proposals (NGET's Original and 26 Workgroup alternatives) have been submitted to us.

3.2. We discuss below the different solutions that have been developed in each of the three areas specified by our direction and we then provide a summary matrix outlining how these different options are combined to form the 27 proposals that have been submitted to us. For a more detailed description of the options developed by industry please see the CMP213 Final Modification Report (FMR) for a complete description of the options.

Summary of the different options developed by industry

3.3. The three tables below summarise the options that have been submitted to us as part of CMP213 for each of the three areas specified by our direction.

Table 1: Reflecting costs of different users

Detail of defect	Proposed solutions
The current charging methodology only recognises peak security as a driver of transmission investment and charges all plant the same tariff for this. This overlooks the second driver of transmission investment as set out in the NETS SQSS – Year Round	Aims to better reflect transmission charging with network investment rules so that charging is cost reflective. **NGET's Original**: Aims to reflect this by splitting the TNUoS tariff into two elements; (i) Peak Security, and (ii) Year Round. The **Peak Security** element would reflect investment for Peak Security reasons. Intermittent generators (eg wind and solar) are not assumed to contribute to Peak Security build, to reflect the background conditions used in the 'Security Background' of the NETS SQSS, and therefore would not be exposed to this element of the TNUoS tariff. The **Year Round** element would reflect investment to relieve constraint costs efficiently. This would be paid for by all generators.

considerations (efficient management of constraint costs). The current TNUoS charging regime does not reflect the two drivers of network investment and how different types of plant contribute toward these.	The tariff would be scaled by the Annual Load Factor (ALF) of the generator which is a measure of how frequently it is operating – a simplifying assumption to reflect the impact of a plant on constraint costs and thus the size of investment. It can also be considered as a proxy for how a plant can "share" transmission capacity with other plants – plants with variable fuel sources and low load factors are more likely to generate at less than full capacity throughout the year and capacity built to accommodate a generation mix that contains a proportion of this generation can typically be "shared" more with higher load factor plant at times when variable sources are unavailable.
	The alternative options developed by the CUSC Workgroup seek to address perceived deficiencies with the NGET Original. **<u>Alternatives featuring Diversity 1</u>:** This recognises that areas dominated by low carbon plant tend to drive more transmission investment for "Year Round" considerations. This is because: • the plants are more expensive to constrain off in the Balancing Mechanism[8] – this is due to the interaction with government's renewable energy support policies; and • low carbon plants often run simultaneously (eg when the wind is blowing) and are therefore less able to "share" transmission network capacity. This approach is the same as the Original until the proportion of low carbon generation exceeds 50% behind a transmission boundary. Beyond this point the level of sharing is assumed to reduce linearly until there is no sharing for areas with 100% of low carbon generation.
	<u>Alternatives featuring Diversity 2</u>: Assumes that high concentrations of either high or low carbon generation in a zone drive higher constraint costs and therefore investment. Under this approach the maximum sharing of transmission capacity occurs when there are equal proportions of low carbon and carbon plant. The level of sharing then reduces linearly as you approach 100% of either low carbon or carbon generation. This approach also applies a 50% cap to the level of sharing which is not present in Diversity 1 described above.
	<u>Alternatives featuring Diversity 3</u>: Reverts back to single charge based on "Year Round" considerations. Like Diversity 2, it assumes that more investment is required where there are high concentrations of either low or high carbon generation. It also assumes the same point of maximum sharing (when equal split of carbon and low carbon generation) and assumes that sharing reduces linearly as you approach 100% of either low carbon or carbon generation. It also applies a 50% cap to the level of sharing. This approach does not recognise peak security as a driver of network investment and it does not recognise that plants within a zone drive different constraint costs and investment (they all get the

[8] NGET can control the volume of generation once dispatched. The main method of managing constraint volumes is to take actions in the Balancing Mechanism to reduce output (or increase for import constraints). For an export constraint the SO will accept bids from the marginal generation plant on the export side of the boundary to reduce output and hence power flows.

	same tariff).
	Counter Correlation Factor: NGET's Original and all alternatives propose to introduce a Counter Correlation Factor (CCF) to reflect situations where a Transmission Owner (TO) has intentionally designed and built a radial transmission link[9] at a reduced capacity to specifically reflect the counter correlation of differing generation technologies.
Sub options	
Load factor assumptions	There is an alternative approach to the calculation of ALF (the load factor) in the Original and in the WACMs featuring Diversity 1 and 2: • average 5 year historical ALF; or • YR forward looking hybrid - choice for generator between average 5 year historical ALF or a forward looking annual forecast of load factor that would need reconciliation at the end of each year, including an incentive to provide an accurate forecast
"MITS[10]" charging definition	Under the Original proposal, NGET proposes a revision to the MITS definition so that all radial transmission circuits would not be classified, for charging purposes, as part of the MITS[11]. These links would be part of the "local" transmission network from a TNUoS charging perspective (and include onshore radial transmission circuitry). This approach effectively excludes such links from a wider Year Round locational element subject to a sharing factor based on load factor. The local TNUoS tariff calculation is not proposed to change. WACMs featuring the diversity solutions (1, 2 and 3) propose to retain the current MITS charging definition. The rationale is that the addition of a further element to the wider Year Round locational element tariff calculation to reflect the composition of generation removes the need to address this impact through other means.

[9] The NETS SQSS allows TOs to make judgments as to the likely output of a generator over the course of a year of operation when setting out minimum transmission capacity requirements. Particularly for generation connecting via relatively expensive links there is precedent for reduced minimum transmission network capacity requirements via a cost benefit assessment. A radial link is a single "spur" that links generation and/or demand in one location to the wider interconnected network. Radial links are therefore single, standalone circuits that represent the lowest cost design solution when considered individually.

[10] Main Interconnected Transmission System. This is the boundary between the "local" transmission network (ie infrastructure assets required close to a generation site) and infrastructure assets in the "wider" transmission network. Section 14.15.26 of NGET's Methodology Statement currently defines a MITS node.

[11] This has no effect on the user commitment MITS node definition.

Table 2: Reflect the development of HVDC bootstraps

Detail of defect	Proposed solutions
These are currently not catered for in the charging methodology There is a need to: a) Reflect DC flows in the current AC only charging model b) Recover cable costs c) Consider whether cost of HVDC converter stations[12] should be included in the locational charging signal or socialised	All of the proposals seek to resolve a) and b) similarly. They propose to recover the cable cost element of these links on a locational basis (ie from the users of the links rather than on a socialised basis). The only difference between the options relates to the treatment of the converter station cost elements (up to 50% of the cost of the overall link). Industry discussions centred on whether converter stations exhibit the same traits as onshore AC substations[13], the costs of which are not recovered on a locational basis. The options presented to us either: • Remove no converter station costs; or • Remove some costs (ie socialise them[14]) ○ 50% based on the cost breakdown of a generic design ○ 60% based on similarity of additional element of design – additional 10% for similarities to Quadrature Boosters (QBs)[15]. • Remove a specific % of costs reflecting the specific cost breakdown of each project that are similar to AC substations.

Table 3: Reflect the potential development of Island links

Detail of defect	Proposed solutions
These are currently not catered for in the charging methodology. There is a need to address a) and b) as above and c) treatment of converter stations (as per HVDC)	All of the proposals seek to resolve a) and b) as per HVDC above c) As with HVDC bootstraps above there are issues around converter stations • Remove no converter station costs, or • Remove some costs[16] ○ 50% (AC substation equivalent) ○ 70% based not on extra QBs but on 20% extra for Voltage Source Converters (VSCs) which some argue will benefit the quality of supplies for demand at the remote end of the link • Remove a specific % of costs reflecting the specific cost breakdown of each project that are similar to AC substations.

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[12] When using HVDC cables, these devices are required to convert the AC power signal to DC and back again and then back again to interface with the existing AC transmission network.
[13] Onshore, transmission substations connect two or more AC transmission lines. Where the lines are of the same voltage, a substation will contain switches that allow lines to be connected or isolated. Where the connecting lines are of different voltages, it may include transformers to change voltage levels (eg 275kv to 132kV). Substations enable power to be transported across long distances and to redirect flows to where the demand is situated.
[14] The expansion factor calculation for HVDC links would exclude some costs components of the converters, thereby reducing the effect on locational tariffs. Hence, wider tariffs would not increase to the same extent as they would under NGET's Original Proposal (ie removing these costs elements further compresses charges, lowers tariffs for generators in the north of Scotland relative to the Original).
[15] QBs provide a means of relieving overloads on circuits and re-routing power via more favourable paths.
[16] See footnote 13.

Changes to Demand TNUoS charges

3.4. Under the proposals submitted to us, the methodology for demand tariffs continues to follow the same principle as under the current methodology eg demand is treated as the opposite of generation

3.5. Investment in transmission network capacity for demand is not affected by the characteristics of that demand, as is the case with generation. As such, although the methodology calculates loadflow in an identical manner to that of generation (ie a Peak Security and Year Round background), it combines these together before multiplying by the charging base. This means that for demand consumers TNUoS charges contain only a single wider locational tariff element (for Half Hourly (HH) and Non Half Hourly (NHH) customers). This should lead to only minor differences in demand tariffs as a result of a small number of transmission circuits that change flow direction between the two backgrounds.

The options recommended by the CUSC panel

3.6. The matrix in appendix 2 presents how these different options above are combined to form the 27[17] proposals that have been submitted to us as part of CMP213. The Panel voted by a majority in favour of 8 of the 27 options. These are alternatives (known as "WACMs") 2, 19, 21, 23, 26, 28, 30 and 33, and are summarised in the table below. For example, WACM 2 features Diversity method 1, using the historical 5 year annual load factor removing no cost from HVDC bootstraps or Island links.

Table 4: CUSC Panel recommended options

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

[17] The Workgroup originally presented 42 options but these were reduced to 27 that they considered viable in the FMR.

4. Quantitative modelling of the charging options

Chapter Summary

This chapter sets out NGET's modelling approach which underpins the quantitative analysis that we present. It examines NGET's analysis of the quantitative impact of the different charging options based on the modelling undertaken. It also sets out our thinking in the light of this analysis.

Question box

Question 1: Do you think we have identified the relevant impacts from NGET's modelling and interpreted them appropriately?

Question 2: Do you have any further evidence of the impacts of the charging options not covered by NGET's analysis?

Purpose of the modelling

4.1. The objective of the modelling presented in this consultation is to provide quantitative evidence of the potential impact of the different options under consideration as part of CMP213. In line with the Project TransmiT objectives it aims to do this by focusing on the impacts in three main areas:

- The impact on power sector costs and the impact on consumer bills.
- The deployment of low carbon generation across GB in order to meet 2020 renewable targets.
- The impact on security of supply (as captured by de-rated capacity margins[18]).

4.2. NGET undertook the modelling analysis as part of the CUSC process using an updated version of the model developed as part of the SCR, and has now updated this for the purposes of our impact assessment. The modelling approach is discussed in the next section, and the results are summarised from section 4.15 onwards.

The modelling undertaken by NGET

The fundamental modelling approach used has not changed from the SCR. The model attempts to mimic transmission and generation build decisions in response to relevant market factors, eg transmission charges and wholesale prices. A Capacity Market is included in the modelling approach to reflect the UK government's Electricity Market Reform (EMR)[19] proposals. Contract for Differences (CfD[20]) strike

[18] The de-rated capacity margin is the capacity margin adjusted to take account of the availability of plant, specific to each type of generation technology. It reflects the probable proportion of a source of electricity which is likely to be technically available to generate (even though a company may choose not to utilise this capacity for commercial reasons).
[19] Further information on the UK government's EMR work is available from the DECC website:

prices are set to reflect the assumption that UK government policy targets for 2020 and 2030 are met. However, the model was updated to reflect, among other things, known changes in Transmission Entry Capacity (TEC)[21] and EMR developments in respect of the Capacity Market. These updates are set out in NGET's "CMP213 Impact Assessment Modelling Report" and discussed in Baringa's "Review of CMP213 Impact Assessment Modelling", both of which are published in parallel to this consultation.

4.3. NGET did not model all 27 options but a selection of the alternatives that are representative of the package of options. We agree that the options modelled by NGET provide a representative range of the different permutations that we must assess.

4.4. The NGET Original and alternatives that feature Diversity 1, 2 and 3 have been modelled twice: once with 100% of HVDC converter station costs included in the wider locational charge (for Island links and HVDC bootstraps), and once with 50% of HVDC converter station costs excluded. All modelling was carried out using 5 year average historical load factors where applicable (the use of load factor is not relevant to the Diversity 3 approach) as the YR forward looking hybrid option was considered too complex to model. This resulted in nine different options being modelled.

4.5. NGET has submitted the results of this analysis and the underlying models to us and they are also published alongside this consultation.

Reviews of the modelling

4.6. We commissioned two pieces of consultancy work to review the updated modelling undertaken by NGET. Both of these have been published alongside this document. Additional detail of the reviews and findings is contained in Appendix 3.

- Baringa reviewed the changes made to the model since the SCR, namely to input assumptions, model functionality/mechanisms and outputs. It has also assessed the likely impact of any changes.
- Lane, Clark and Peacock (LCP) carried out a quality assurance review of NGET's modelling work. The primary aim of LCP's review was to assess whether NGET's modelling approach had been implemented correctly. We also asked LCP to provide high level comment on the approach itself.

4.7. Baringa's report concluded that the changes made by NGET to the modelling assumptions and functionality for the CMP213 modelling were reasonable and produce results that are consistent with the changes made. Some updates have had

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http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx

[20] Under a CfD the purchaser (typically an electricity retailer) agrees in advance to purchase a specified physical quantity of energy from the spot market at a set price (the "strike price"). If the actual price paid in the spot market by the purchaser is higher than the strike price, the counterparty to the contract (typically an electricity generator or a financial institution) pays the purchaser the difference in cost. Conversely, if the price paid is lower than the strike price, the purchaser pays the counterparty the difference.

[21] TEC is the maximum amount of electricity a generator is allowed to export onto the NETS and is stated in Megawatts (MW). TEC is an element of the TNUoS charge all generators pay. In terms of charge differentiation, generators tariffs currently reflect not only their location, but also their TEC.

a significant impact on the results. The increase in total offshore wind and nuclear capacity drive most of the differences in power sector costs, and changes to the Capacity Market have led to lower capacity margins.

4.8. LCP identified a number of minor issues with the implementation of the modelling approach that it did not think materially affected the conclusions reached. However, it considered that the effect of the modelling simplifications should be taken into account when drawing any conclusions based on the results of the analysis.

4.9. LCP did identify an issue with the implementation of alternatives that feature Diversity 3 within the tariff and transport model, which had an impact on modelling results. NGET has since corrected the model in this respect and provided us with updated results.

Interpreting the modelling results

4.10. Due to the complex nature of the energy market and TOs’ transmission investment decisions, the model used in the impact analysis of the CMP213 proposals is necessarily complex but at the same time must make simplifying assumptions. As identified by LCP, some of these simplifications influence the results – notably the way that CfDs and the Capacity Market have been modelled. This view is reinforced by the conclusions of the Baringa report. Baringa noted that relatively subtle differences in transmission charges under the Status Quo and the Original can be dominated by other factors including:

- the availability of sites for new low carbon generation and the deployment rates for renewable technologies;
- the differential support levels for low carbon generators under the Renewables Obligation and assumed under EMR;
- the lumpiness of onshore transmission reinforcement; and,
- the effect of low carbon support on constraint costs.

4.11. The modelling results must be interpreted taking these issues into consideration. Therefore, while we consider that the modelling results provide a view of the relative impacts of the modelled CMP213 proposals, we think that they only provide an approximate guide as to the likely “real world” impacts of the different proposals with a broad sense of the magnitude. As such, the qualitative analysis supporting our decision is also important.

4.12. We have given some consideration as to whether the industry analysis and our consultants’ reviews are adequate to support our decision, or whether we need to undertake additional analysis. We do not propose to undertake further modelling at this stage. The question being addressed by the model is very complex and we have concluded that it is highly unlikely that any other model would provide materially more robust findings than the current model without significant delay to the process (if at all). Overall we therefore do not think it is proportionate or in consumers’ interests to delay the process further and undertake more modelling.

4.13. We also note that some of the modelling assumptions are now out of date. For example, there have been further TEC changes that are not reflected in the model, and the latest 2013 'Gone Green' demand forecasts[22] are lower than those used in the model.

4.14. All the impacts provided below are for modelling which adjusts levels of low carbon support so that each charging approach results in broadly equivalent levels of renewable generation. This facilitates comparison on a 'like with like' basis.

The modelling results

4.15. The remainder of this section summarises the overall quantitative analyses conducted by NGET for all the modelled charging options. This section is a summary, the complete analysis is contained in the NGET modelling results and the Redpoint energy document published alongside this document, these documents form part of our impact assessment.

4.16. The CMP213 Workgroup agreed that the impact analysis of the modelling undertaken by NGET should be carried out on six models representative of potential future scenarios. In June 2013, we requested that NGET provide modelling results for a further three models. These models, and their reference to the 27 alternatives considered in the FMR, are set out in Table 5 below.

Table 5: NGET modelling options summary

Model	Charging option	Approach to diversity	HVDC links (% converter station costs in locational charge)	Island links (% converter station costs in locational charge)
1	Status quo	As per current methodology	100%	100%
2	NGET's Original proposal	Sufficient diversity assumed to exist	100%	100%
3	WACM 2	Diversity 1	100%	100%
4	WACM 3	Diversity 2	100%	100%
5	WACM 4	Diversity 3	100%	100%
6	WACM 28	As per Original proposal	50%	50%
7	WACM 30	Diversity 1	50%	50%
8	WACM 31	Diversity 2	50%	50%
9	WACM 32	Diversity 3	50%	50%

4.17. We present the following types of impacts for the each of the modelled charging options (results for WACMs 30, 31 and 32 are provided where the result diverges from the results for WACMs 2, 3 and 4 respectively):

- **Impacts on transmission charges:** an overview of impacts on generator tariffs, tariff movements, regional impact on generators and regional impact on demand tariffs. This section highlights distributional impacts.

[22] "Gone Green" is a modelling scenario (not a forecast) designed by National Grid to meet the UK government's legally binding climate change policy targets. Gone Green assumes that the correct economic incentives are in place to ensure these targets are met..

- **Overall cost impacts**: an overview of impacts on power sector costs and consumer bills.
- **Power Sector costs**: the aggregate impacts on power sector costs and the impacts on factors that affect power sector costs such as generation costs, cumulative new build, retirement, transmission costs and constraint costs.
- **Consumer Bills**: the aggregate impacts on consumer bills.
- **Impacts on security of supply**: measured using de-rated capacity margins.
- **Impacts on sustainability goals:** estimated using NGET's analysis, with low carbon support adjusted across the charging options.

Impacts on transmission charges

Overview

4.18. The allowed revenue that the transmission companies are permitted to collect, known as the Maximum Allowed Revenue (MAR)[23] under all options is projected to increase over the modelling period. This reflects the costs they would be expected to incur. The modelling suggests that this would be reflected in increasing transmission charges on average under any option including the Status Quo. The split of total transmission costs between generation and demand is assumed to remain at 27:73 under all options.

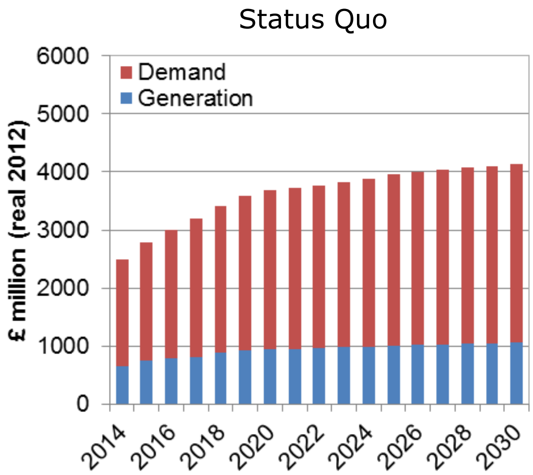
4.19. The base revenues have been calculated in accordance with the RIIO-T1[24] Final Proposals, and have been projected forward beyond the end of the forthcoming price control period out to 2030/31.

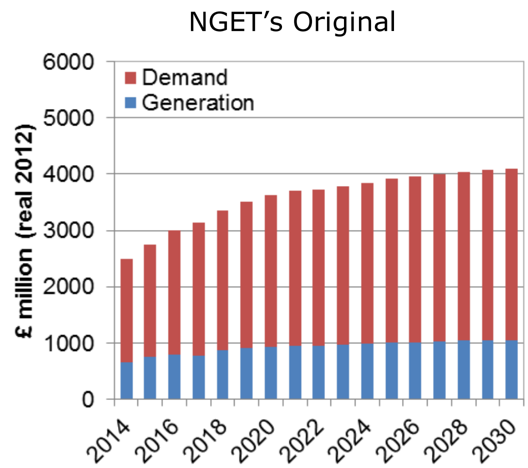
4.20. Projected changes in allowed TO revenues (particularly due to the introduction of new offshore networks) are the main driver behind year on year tariff changes that the analysis shows, particularly zonal demand tariffs. It can also be noted that aside from the effect of HVDC links being commissioned, the year on year projected generator tariff trends largely align with the changes in TO allowed revenue.

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

[24] RIIO is Revenue = Incentives+Innovation+Outputs. RIIO-T1 is the first transmission price control review to reflect the new regulatory framework.

Figure 1 : Annual Transmission Costs under Status Quo and NGET's Original





4.21. For the three main approaches to dealing with Diversity (Diversity 1, 2 and 3), the impact on the level of annual transmission costs is very similar. By 2030, charges recovered from generators are roughly £1bn under all the options, whilst charges recovered from demand are roughly £3bn.

4.22. The general trend is the same for the diversity options combined with the removal of 50% of the costs of HVDC/island converter stations.

4.23. The remainder of this section looks at the distributional impacts of the transmission tariffs for both generators (generator tariffs, tariff movements, regional impacts on generators) and demand (regional impacts on demand tariffs)

Generator tariffs

4.24. All charging proposals, with the exception of Status Quo and Diversity 3[25], assume a dual background (peak security and Year Round) approach for assessing the incremental transmission network costs imposed by generators. A generator's TNUoS charge would therefore be comprised of the following four components:

- ***A peak security wider tariff:*** charged on capacity (TEC in MW) and levied only on non intermittent generators as described in Chapter 2.
- ***Year round wider tariff***: in positive generation charging zones, charged on capacity (TEC in MW) and scaled by the annual load factor specific to each generator. In negative generation charging zones, charged on average metered output and scaled by the annual load factor.
- ***Residual element***: would continue to ensure the full recovery of the revenue that onshore and offshore TOs have been allowed in their price controls[26]. CMP213 does not alter the residual calculation relative to the Status Quo.

[25] Under Status Quo and Diversity 3, all types of generator would be subject to a charge based on a single background condition.
[26] To ensure the correct level of revenue is collected through each locational charge, a 27:73 split will be obtained for each triggering criterion 'pot', without altering the size of the total pot.

- ***Local tariff*[27]:** the proposals would not alter the local substation or local circuit charges calculation relative to the Status Quo, although the NGET Original proposal proposes to alter the extent to which circuits are defined as local or wider. However, the recalibration of this would have minimal impact on the local tariff relative to the Status Quo.

4.25. Relative to the Status Quo option, low load factor generators in positive charging zones would see lower transmission tariffs under all options, and the corresponding charges would be higher in negative charging zones. The effect would be more pronounced for low load factor generators who would not pay the peak security wider tariff in the Original and diversity options 1 and 2.

4.26. Across the time period modelled, the Status Quo provides the greatest range of locational differentials. NGET's Original provides the lowest range of locational differentials (the 50% HVDC variant reduces this further). Diversity 2 provides the next lowest range of differentials.

4.27. The tariffs under the Diversity 3 options are most similar to the Status Quo and therefore have a wider range of tariffs than the other options.

4.28. The impacts of the range of charging options utilising the dual background approach is shown in the table below. These compare an intermittent generator with a 30% load factor and a conventional generator with a 70% load factor. In general, the modelling results suggest that the effect of NGET's Original and alternatives that feature Diversity 1 and Diversity 2 is to 'compress' locational variations in generation TNUoS charges, particularly for low load factor generators (including variable and intermittent renewables)[28]. This can be seen in the figures below which compare the different approaches to diversity (with 100% HVDC costs included in locational charge) for non intermittent (70% load factor) and intermittent (30% load factor) generators:

[27] It is proposed to levy CMP213 on the wider element of charge only because "local" infrastructure reflect elements of transmission build made for a specific user (or users), which therefore limit the potential for sharing of transmission network capacity and, as such, are sized to that user's (or users') capacity. Hence, the Local transmission charge elements reflect the full cost of the build rather than an amount based on its usage.

[28] These tariffs have been produced by NGET according to the 2011/12 generation charging zones. A short explanatory note written by NGET on its modelling approach is published alongside this.

Figure 2: 2014 tariffs for non intermittent generators (70% load factor)

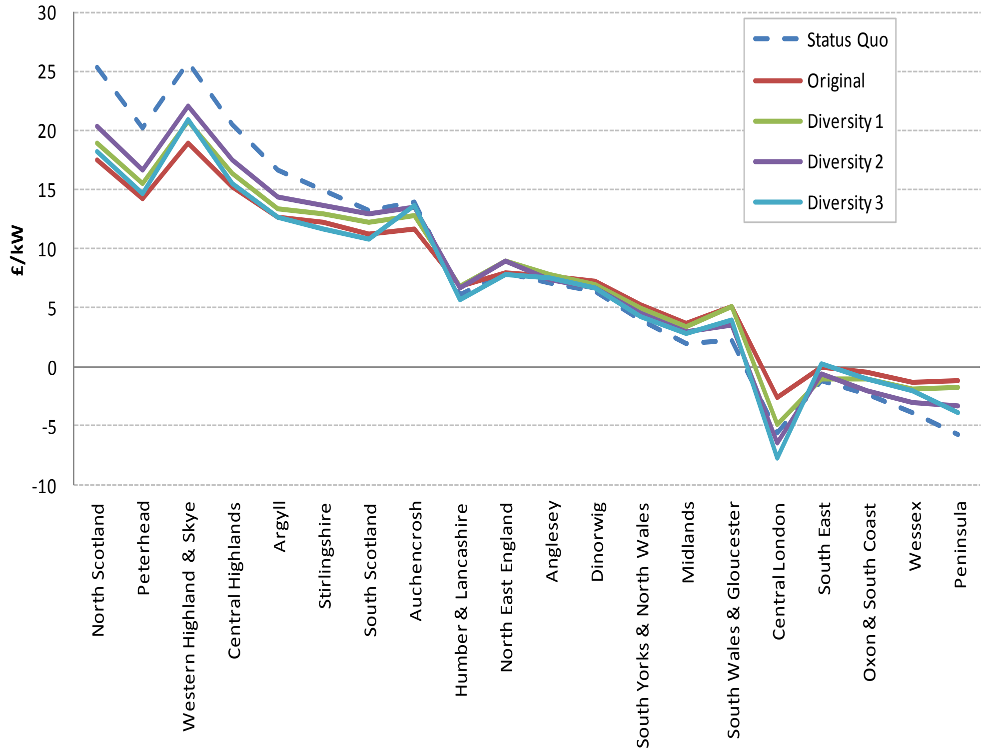
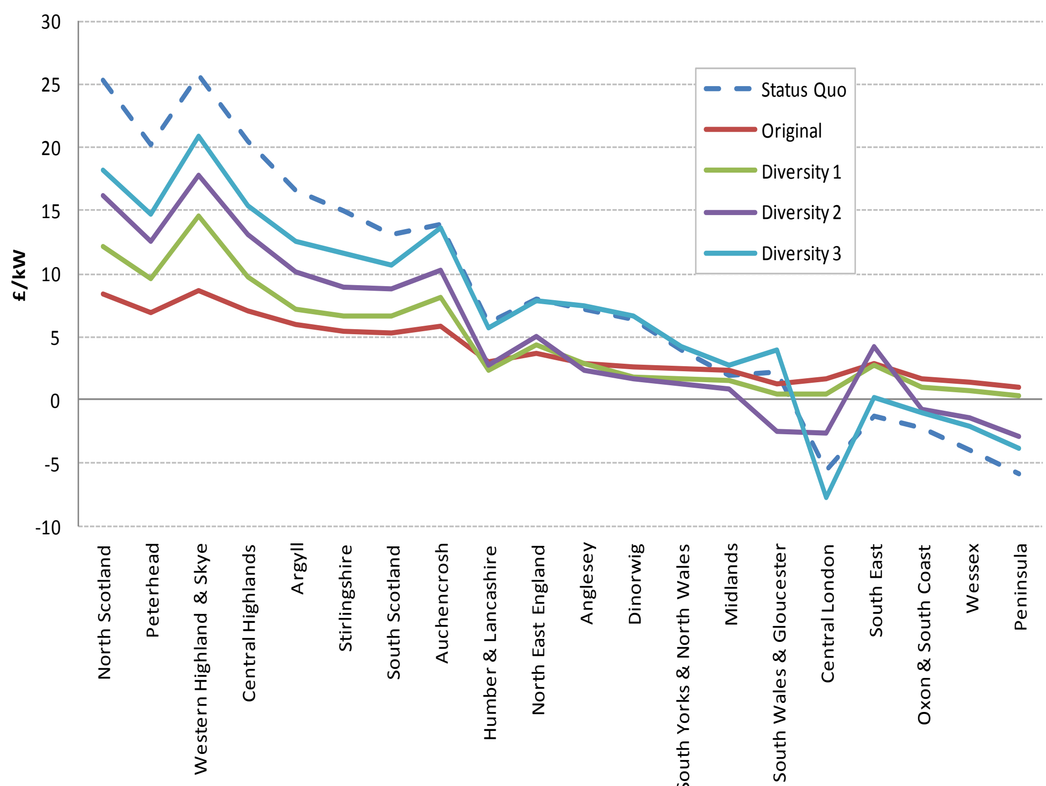


Figure 3: 2014 tariffs for intermittent generators (30% load factor)



4.29. Table 6 below shows the tariff range modelled in 2020 between North Scotland and Central London for both baseload and intermittent plant. The 50% HVDC variants mainly affect tariffs in the zones that are users of the HVDC links.

Table 6: 2020 Tariff Ranges between North Scotland and Central London for NGET Original, Diversity 1 and Diversity 2 and variants

£/kW	Region	NGET Original	Diversity 1	Diversity 2	NGET Original (50% HVDC)	Diversity 1 (50% HVDC)	Diversity 2 (50% HVDC)
Intermittent (30% load factor)	North Scotland	12.2	24.2	26.3	11.6	22.6	24.9
	Central London	1.7	-0.5	-4.4	1.9	-0.2	-3.6
Non Intermittent (70% load factor)	North Scotland	23.0	25.7	26.5	21.3	23.9	24.9
	Central London	-2.1	-5.3	-7.6	-1.9	-4.9	-6.8

4.30. The 50% HVDC variant of the NGET Original would lead to the most compressed tariffs across GB, particularly for low load factor plant.

4.31. It can be observed that, all else being equal, zones which currently have high TNUoS charges, such as North Scotland, become more attractive for siting plant with lower load factors (including low load factor thermal generation) and zones which currently have low positive, or negative TNUoS tariffs, such as the south of England, become less attractive for plant with this characteristic. This effect is more pronounced in the Original and Diversity 1 options (especially the 50% HVDC variants) than Diversity 2. Diversity 3 is very similar to the Status Quo for the reasons noted above.

Regional impacts on generators

4.32. All CMP213 options will change the profitability of generating plant according to their location. The analysis indicates that over the longer term all options will reduce generator profits relative to the Status Quo due to reduced wholesale electricity prices.

4.33. Out of the four diversity options considered, Diversity 3 has been found to result in the lowest generator profits in the short term and reductions in profit levels in the longer term for all generators across GB (relative to the Status Quo).

4.34. The Diversity 1 and Diversity 2 options lead to very similar profits for generators, with Diversity 2 leading to slightly higher profits over the period 2021 – 2030 due to a combination of higher wholesale prices and higher investment in offshore wind.

4.35. Compared to the Status Quo, the diversity options favour generators in what are currently high TNUoS charging zones in Scotland, as illustrated below. Specifically, under Diversity 1 generator profits are higher in Scotland in the short term and relatively unaffected in the longer term (whereas they are lower in south England, the Midlands and Wales).

Figure 4: 2014 -2020 Average annual change in total generator profits, relative to Status Quo – Diversity 1

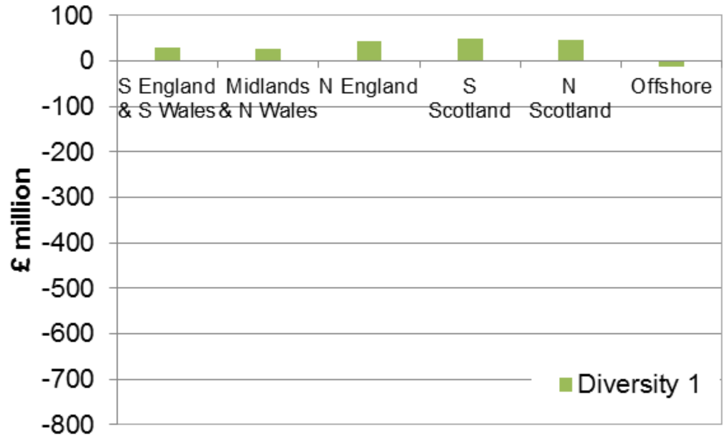
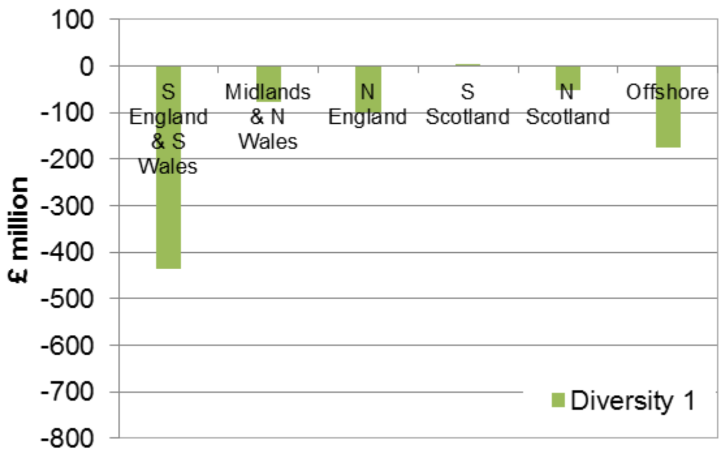


Figure 5: 2021 - 2030 Average annual change in total generator profits, relative to Status Quo – Diversity 1



Regional Demand tariffs

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

4.37. The change to the calculation of the wider locational element of demand charges produces very similar charges across the Status Quo and alternative charging approaches. As such, differences in demand TNUoS charges between the Status Quo and the modelled alternatives are relatively minor and are driven almost entirely by differences in generation and transmission backgrounds.

4.38. The figures below show the HH and NHH demand tariffs by region for 2014 for the different approaches to diversity (100% HVDC cost in locational charge).

Figure 6: 2014 HH demand tariffs

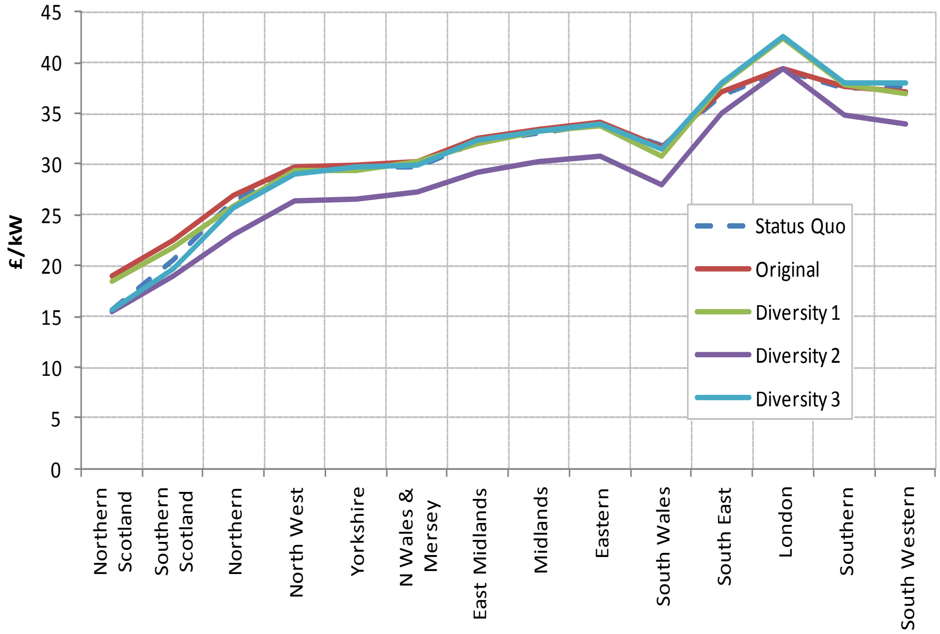
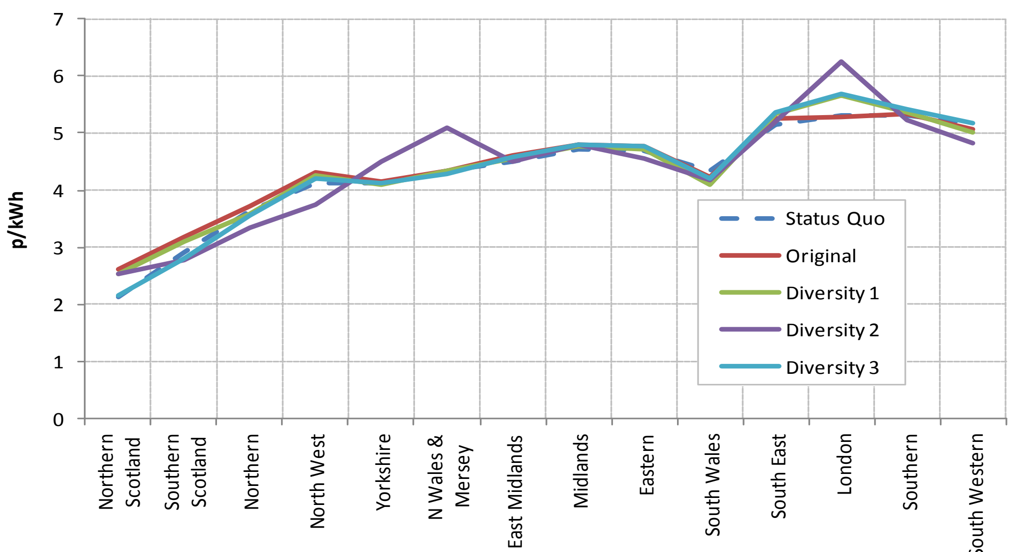


Figure 7: 2014 NHH demand tariffs



4.39. NGET's Original shows reductions compared to Status Quo in demand tariffs for regions where demand is greater than generation (South England and South Wales) but increases for consumers located in regions where generation is greater than demand (North Scotland). A similar trend has also been found to take place under alternatives that feature Diversity 1 and Diversity 2 methods.

4.40. On the other hand, demand TNUoS charges under the alternatives that feature Diversity 3 are very similar to the Status Quo. There are some small increases for customers in Scotland due to differences in transmission and generation investment, however, the regional impact on consumers remains similar.

4.41. In terms of the diversity options that seek to socialise a greater proportion of HVDC converter station costs, the charges for generators north of the link (putting power onto the link) will be lower relative to an option that does not. Conversely, generators in areas below the exit point onto the system from the HVDC bootstrap will pay relatively higher generator charges. The model indicates that marginal generation is located in these southern areas. It is observed that as these generators are paying relatively more, the capacity payments assumed by the model will be greater and the wholesale costs will be larger. In the tables below, positive numbers show an increase from the Status Quo and negative numbers a decrease.

Table 7: Change in demand TNUoS element of bill vs. Status Quo (£/customer)

	Original – change from Status Quo			Diversity 1 – change from Status Quo		
	£/year			£/year		
	2014	2020	2030	2014	2020	2030
N Scotland	£1.88	£2.40	£3.56	£1.60	£3.27	£4.38
S Scotland	£1.24	£2.34	£3.71	£0.81	£3.25	£4.21
N England	£0.26	£0.03	£0.26	-£0.12	-£0.19	£0.23
Midlands & N Wales	£0.20	-£0.43	-£0.27	£0.04	-£0.72	-£0.62
S England & S Wales	£0.06	-£0.25	-£0.59	£0.37	-£0.20	-£1.08

Table 8: Change in demand TNUoS element of bill vs. Status Quo (£/customer)

	Diversity 1 (50%) – change from Status Quo		
	£/year		
	2014	2020	2030
N Scotland	£1.60	£4.53	£5.56
S Scotland	£0.81	£4.60	£5.48
N England	-£0.12	-£0.20	£0.22
Midlands & N Wales	£0.04	-£0.89	-£0.78
S England & S Wales	£0.37	-£0.36	-£1.23

Impacts on overall costs

4.42. The analysis shows the impact of the charging options versus the Status Quo on a) power sector costs and b) consumer bills. Power sector costs are comprised of costs associated with changes to provision of generation to meet demand, the provision of transmission network, level of constraints and costs of carbon. Hence it represents the change in total cost to society of meeting electricity demand. Consumer bill impacts measure the direct impact on consumers. They are comprised of costs that together form the consumer bill.

4.43. Table 9 shows the impact on total power sector costs relative to Status Quo for the period to 2020 under NGET's Original and diversity options 1, 2 and 3.

4.44. The NGET Original and Diversity 1 variants lead to the lowest power sector costs due to the greatest reduction in generation and transmission costs, while Diversity 3 leads to the lowest decrease in power sector costs up to 2020.

4.45. An increase in consumer bills is observed across the period for all options relative to the Status Quo. Diversity 2 has the smallest decrease in power sector costs and the largest increase in consumer bills.

4.46. In the period 2021 to 2030, Diversity 1 variants (100% and 50% HVDC treatment) produce the largest decreases in power sector costs. It is observed that Diversity 3 leads to an increase in power sector costs due to large increases in generation costs. This is largely explained by the differences in generation costs, which are mostly driven by different generation profiles of renewable technologies.

4.47. In terms of consumer bills, Diversity 3 leads to the largest decrease in due to the greatest reduction in wholesale costs, the second largest decease is under Diversity 1. Diversity 2 is observed to have an increase in power sector costs and the lowest decrease in consumer bills. Changes in consumer bills are dominated by changes in the wholesale cost of power (including capacity payments). While capacity mixes are similar overall under the modelling, the differences in wholesale costs can be explained by the different capacity margins, with tighter capacity margins leading to an increase in power prices.

4.48. Under all options, before 2024, wholesale costs were found to be higher compared to the Status Quo due to tighter capacity margins. This trend is reversed from 2025 onward. Diversity 3 has the highest margins and also the greatest investment in low carbon technology with low marginal cost. However, low wholesale prices result in higher low carbon support under the model (due to CfD top-up payments). These factors interact but the wholesale cost effect is especially dominant under Diversity 3.

4.49. Table 10 below summarises the cost analysis (i.e. power sector costs and consumer bill impacts) for the period until 2020 (first table) and the period 2021 to 2030 (second table).

Table 9: Cost analysis [29]

		NPV 2011-2020 (£m real 2012)						
		Diversity 1 (Option 2)	Diversity 1 (50% HVDC) (Option 30)	Original	Diversity 2	Diversity 3	Diversity 2 (50% HVDC)	Diversity 3 (50% HVDC)
Benefit relative to Status Quo								
Power sector costs	Generation costs	931	931	958	349	308	929	308
	Transmission costs	143	143	137	73	28	141	28
	Constraint costs	-34	-34	-40	-29	-32	-34	-32
	Carbon costs	-116	-116	-104	-45	-35	-116	-35
	Decrease in power sector costs	**924**	**924**	**950**	**348**	**269**	**921**	**269**
Consumer Bills	Wholesale costs (inc. capacity payments)	-1,725	-1,740	-1,729	-1,382	-1,166	-1,776	-1,180
	BSUoS	-17	-17	-20	-15	-16	-17	-16
	Transmission losses	-42	-42	-48	-33	-28	-43	-28
	Demand TNUoS charges	135	135	135	78	41	135	41
	Low carbon support	930	929	892	359	224	929	224
	Decrease in consumer bills	**-719**	**-735**	**-770**	**-992**	**-944**	**-771**	**-959**

		NPV 2021-2030 (£m real 2012)						
		Diversity 1 (Option 2)	Diversity 1 (50% HVDC) (Option 30)	Original	Diversity 2	Diversity 3	Diversity 2 (50% HVDC)	Diversity 3 (50% HVDC)
Benefit relative to Status Quo								
Power sector costs	Generation costs	517	615	-84	-579	-762	750	-723
	Transmission costs	407	402	214	236	324	402	255
	Constraint costs	43	43	33	-3	-9	43	-9
	Carbon costs	58	34	257	304	-128	32	-79
	Decrease in power sector costs	**1,025**	**1,094**	**420**	**-41**	**-576**	**1,226**	**-557**
Consumer Bills	Wholesale costs (inc. capacity payments)	3,517	3,300	4,194	2,895	7,070	1,626	5,900
	BSUoS	21	21	17	-1	-5	21	-5
	Transmission losses	32	33	-42	28	33	32	17
	Demand TNUoS charges	274	270	187	152	212	270	173
	Low carbon support	667	708	-397	-463	-1,210	1,212	-1,044
	Decrease in consumer bills	**4,511**	**4,332**	**3,958**	**2,610**	**6,102**	**3,161**	**5,042**

Power sector costs

4.50. This section considers the overall trend in power sector costs and then describes the factors that affect this namely generation costs, cumulative new build, retirement decisions, transmission costs and constraint costs.

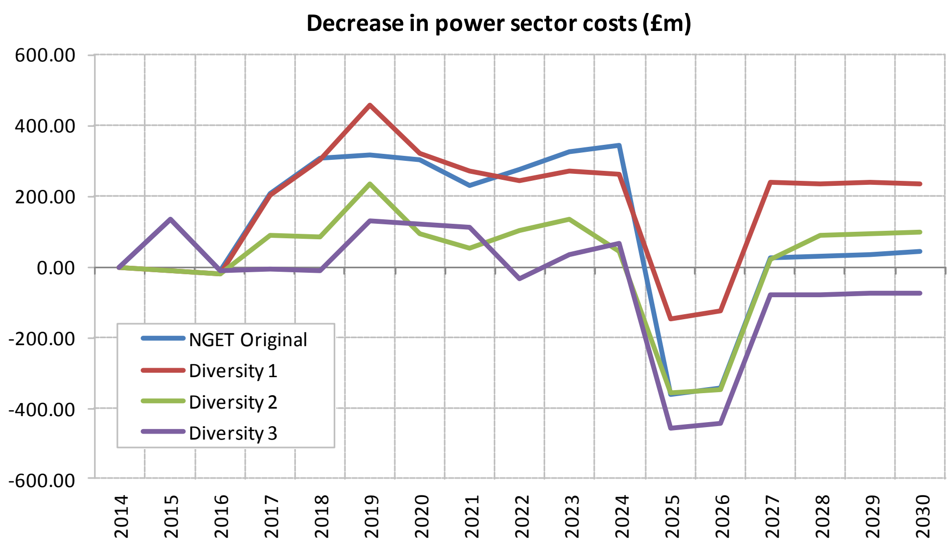
[29] Positive figures represent cost increases relative to the Status Quo. Negative numbers represent cost decreases (savings) relative to the Status Quo.

Overall trend in power sector costs

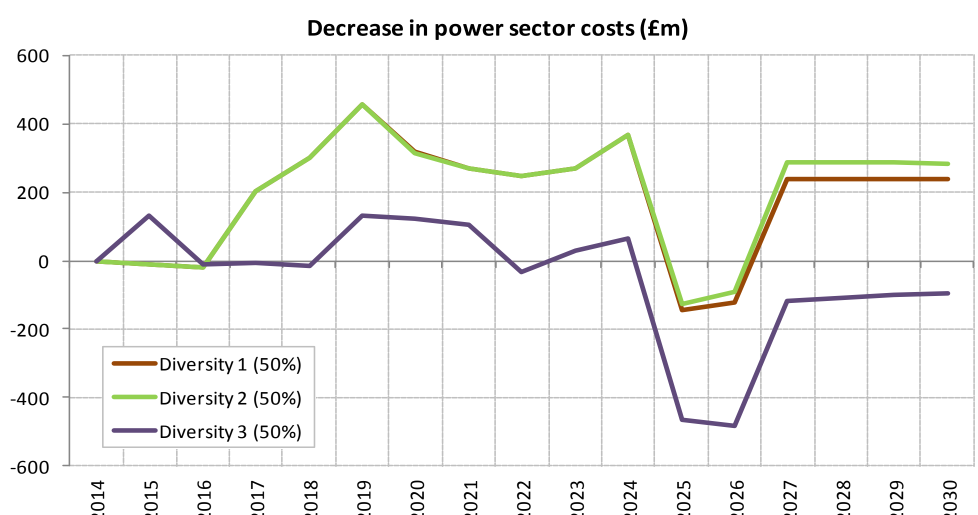
4.51. The year by year changes in power sector costs relative to the Status Quo are illustrated in Figure 8.

4.52. To aid understanding we have separate graphs showing options where 100% of the cost of HVDC converter stations is included in the locational charge (first graph) and options where only 50% of the cost of converter stations is included in the locational charge (second graph).

Figure 8: Net power sector cost impact relative to the Status Quo



NOTE: positive numbers reflect a decrease in power sector costs.



4.53. Overall, Diversity 1 with 100% converter station costs in the locational charge leads to the lowest power sector costs, followed by Original with 50% converter station costs included in the locational charge, whilst Diversity 3 leads to the highest power sector costs. These differences can largely be explained by differences in generation costs, which are mostly driven by different investment profiles in renewable technologies.

4.54. The graphs show that NGET's Original delivers an overall saving in power sector costs relative to the Status Quo. This is mainly due to savings caused by the replacement of offshore wind with onshore wind (and the lower level of renewable generation overall). Conversely, diversity options 2 and 3 (and their variants) are closer to the Status Quo power sector costs results overall. Diversity 1 (and the variant) shows the largest savings, due to continued lower offshore wind generation relative to other models.

4.55. The overall trend observed across each option is a saving in most years, although the earlier build of CCGT plus CCS imposes a larger cost in 2025 and 2026 in Diversity 2 and 3 relative to NGET's Original and Diversity 1. Diversity 2 shows a net increase in costs (and NGET's Original shows a net decrease) since the overall level of renewable generation is higher under Diversity 2. Both Diversity 3 options show a large increase in generation costs. The drivers of this effect are the additional investment in new CCGT capacity and the higher level of renewable generation overall.

Generation costs

4.56. Generation costs are considerably lower under Diversity 1 options (100% HVDC treatment) relative to all other options due to savings in generation capital costs and fixed costs associated with replacing offshore wind with onshore wind. By 2030 Diversity 1 results in the lowest overall level of renewable generation to achieve the policy targets (10.1GW, see Table 11 below). Under all options there is no growth in offshore wind after 2020. The greatest deployment of offshore wind is observed under Status Quo and Diversity 3 (12.2GW and 11.3GW respectively).

4.57. The main difference in the generation mix observed between Diversity 1 and Diversity 2 is that slightly more offshore wind is being built by 2020 in Diversity 2 (0.8GW built in the south), see Table 10 below. This effect is maintained and amplified under Diversity 3 (1.2GW versus the level observed under NGET's Original and alternatives that feature Diversity 1). There are no differences in generation mix between diversity options and their respective 50% HVDC variants across the modelling period. In the period from 2021-2030 (see Table 11 below), Diversity 3 (with 100% HVDC converter station cost included in the locational charge) drives the construction of an additional nuclear plant relative to the Diversity 3 variant option.

Table 10: Carbon intensity and renewable penetration results 2020

	Status Quo	Original	Div 1	Div 2	Div 3	Div 1 (50%)	Div 2 (50%)	Div 3 (50%)
Onshore Wind (GW)	9.6	10.1	9.9	9.9	9.9	9.9	9.9	9.9
Offshore Wind (GW)	11.3	10.1	10.1	10.9	11.3	10.1	10.1	10.7
Renewable Penetration	30.4%	29.7%	29.6%	30.3%	30.6%	29.6%	29.6%	30.1%

Nuclear (GW)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Coal and CCS (GW)[30]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Carbon intensity (G/KWh)	246.8	251.6	252.1	248.7	247.1	252.1	252.1	249.7

Table 11: Carbon intensity and renewable penetration results 2030

	Status Quo	Original	Div 1	Div 2	Div 3	Div 1 (50%)	Div 2 (50%)	Div 3 (50%)
Onshore Wind (GW)	11.1	11.6	11.4	11.4	11.4	11.4	11.4	11.3
Offshore Wind (GW)	12.2	11.0	10.1	10.9	11.3	10.1	10.1	10.7
Renewable Penetration	32.8%	32.1%	31.3%	31.9%	31.9%	31.3%	31.3%	31.4%
Nuclear (GW)	14.8	14.8	14.8	14.8	15.2	14.8	14.8	15.2
Coal and CCS (GW)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Gas and CCS (GW)	3.4	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Carbon intensity (G/KWh)	99.0	96.6	99.5	97.5	96.0	99.5	99.5	97.8

Cumulative new build

4.58. The next sections summarise the build decisions by three main category of plant: CCGT, low carbon, nuclear and CCS.

CCGT

4.59. With regards to CCGT build, there are no differences between NGET's Original and the three main Diversity methods until 2020 (new build or retirement decisions) although all are different from the Status Quo.

4.60. There are no significant differences in the level of new CCGT capacity build or in the location of that capacity between 2020 and 2030 between NGET's Original, Diversity 1 and 2 or their variants. For these options investment continues in the South England and South Wales region only.

4.61. Modelling of Diversity 3 shows that 2.7 GW more CCGT capacity is built by 2030.

Low carbon

4.62. NGET's Original and variants have more onshore wind generation capacity and less offshore capacity than the Status Quo across the modelling period. In total the renewable generation capacity is slightly lower under NGET's Original than Status Quo.

[30] Coal and CCS only.

4.63. Diversity 1 and variants produce a level of renewable capacity that is closest to NGET's Original relative to the other diversity approaches. Alternatives that feature Diversity 3 produce results most similar to Status Quo. The capacity mix under Diversity 1 and Diversity 2 is very similar, with the only difference being that Diversity 2 results in an additional 0.8 GW of offshore wind capacity, all of which is located in the south of England. This is most likely due to the lower generator tariffs.

4.64. The differences between the alternatives that feature Diversity 2 and between the alternatives that feature Diversity 3 are minimal. We also note that the differences between the Diversity 1 and Diversity 2 variants are small throughout the modelling period, suggesting that the compression of tariffs is similar.

4.65. The additional onshore wind under NGET's Original and variants is located in North Scotland. This is where tariffs are reduced most compared to the Status Quo. The reduction in onshore wind is in the south of England (where tariffs generally increase).

Nuclear and CCS

4.66. The results of nuclear build decisions and CCS are almost identical across the range of modelling runs. Alternatives that feature Diversity 3 are observed to have an additional 0.4GW of nuclear capacity by 2030.

4.67. The results for the Diversity 1 variants are identical up to 2023. After 2023 the differences are related to a one year delay in the deployment of a CCGT plus CCS plant in the south of GB for the option which includes only 50% HVDC converter station costs in the locational charge.

Retirement decisions

4.68. The changes to transmission charging are seen to impact on marginal retirement decisions only, and therefore while the transmission charges themselves may change the overall profitability for all generators, the changes in these tariffs cause limited differences in retirement decisions. The main impact is on the timing of retirement decisions.

4.69. Under alternatives that feature Diversity 3, there is an additional retirement of 3.2GW of older (existing) CCGT between 2021 and 2026 relative to the Status Quo.

Transmission costs

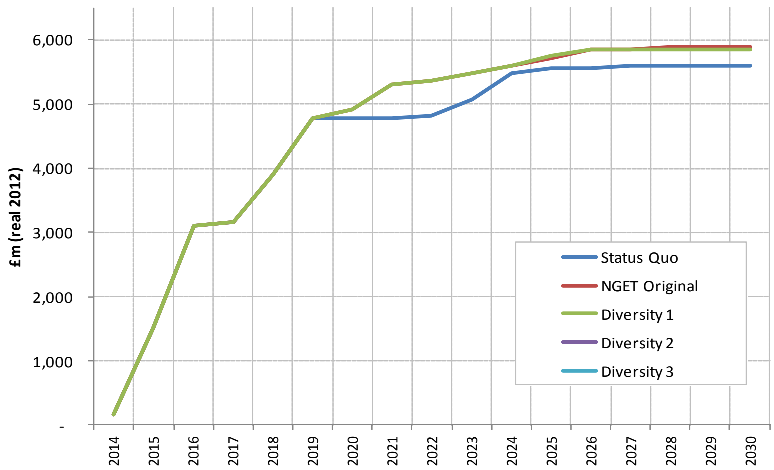
4.70. Figure 9 shows the reinforcement costs to the MITS under all modelled options. It can be seen that network reinforcement is identical up to 2019, and there are no differences in terms of HVDC links. (Western HVDC in 2016 and Eastern HVDC in 2019.)

4.71. After 2019, there is a slower rate of investment in the onshore transmission system relative to prior years. However, the East coast upgrade is seen to be brought forward relative to the Status quo (by three years). This upgrade reinforces internal Scottish boundaries and is due to increased volumes of onshore renewables using this part of the system.

4.72. Onshore reinforcement costs and transmission losses were found to be very similar across the four main alternatives (Original, Diversity 1, 2 and 3). However, Diversity 3 has been shown to lead to very similar investment profile to Status Quo, which reduces transmission costs overall (the lines are overlapping in the figure below). Constraint costs and low carbon costs are almost identical and are not major factors driving these cost impacts.

4.73. The impact on cumulative transmission investment is shown in the figure below.

Figure 9: Cumulative transmission investment

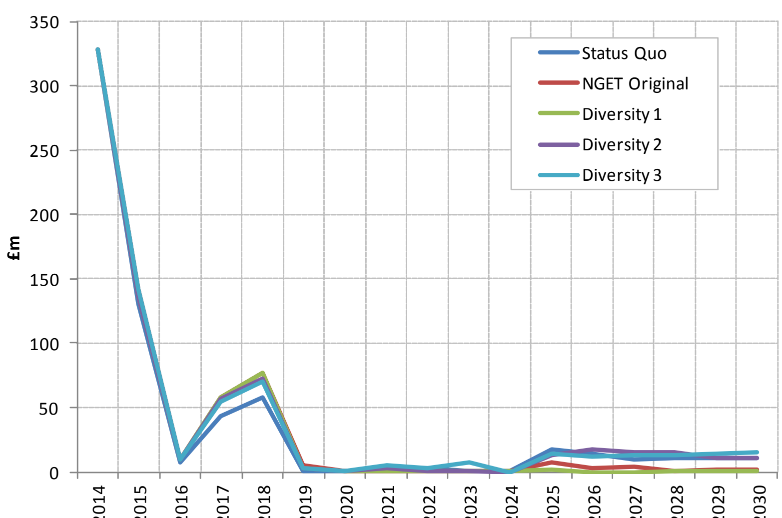


Constraint costs

4.74. Constraint costs are mainly attributed to the boundaries affecting flows from Scotland to England (ie B6) and export flowing south from northern England (B7a). These system constraints are removed by the bootstrap reinforcement projects in all models. Constraint costs remain at a low level throughout the period due to the slow rate of onshore wind build after 2020.

4.75. Figure 10 illustrates the trajectory of constraint costs under each of the alternative charging options.

Figure 10: Constraint cost impact



Consumer bills

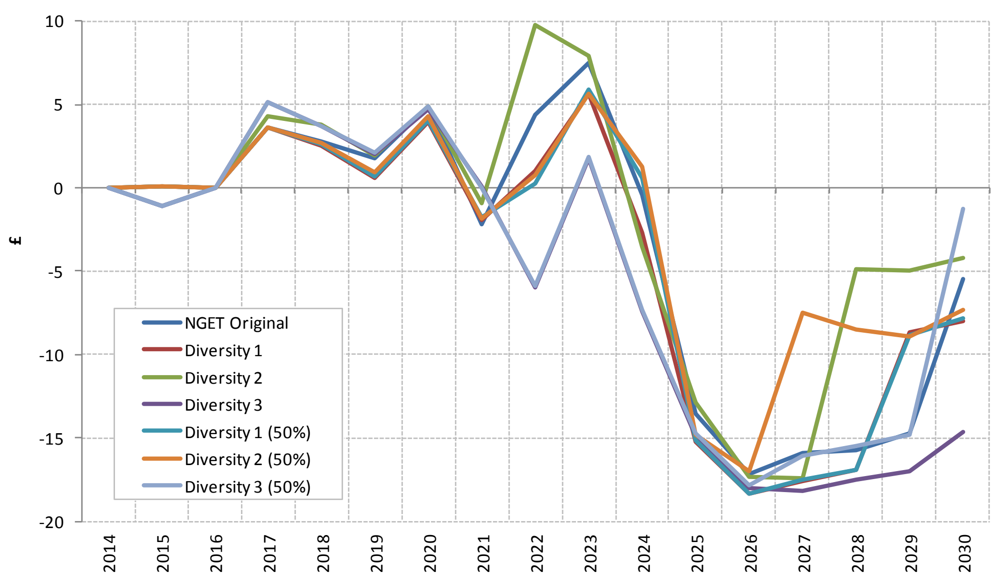
Overall impact

4.76. The changes in consumer bills include effects from BSUoS charges, transmission losses, demand TNUoS charges (see above) and low carbon support provided to generation. However, the dominant factor is the wholesale cost of power (including capacity payments). The differences in wholesale costs are mainly the result of different capacity margins, with tighter margins leading to an uplift in the short run power price.

4.77. The wholesale costs, for all modelled options are shown to be higher relative to the Status Quo until 2020. This is due to tighter capacity margins (as shown in Figure 12). However, this trend is reversed later in the modelling period as wholesale cost reductions are realised under all runs due to more efficient investment decisions being made by plant. While all options are seen to deliver higher margins than the Status Quo during the 2024-2026 period, margins under Diversity 2 revert to the Status Quo levels as a result of tighter margins resulting in higher prices (compared to the other options).

4.78. Figure 11 below shows the change in the bill (averaged throughout GB) for an average domestic customer using 4000kWh of electricity each year. Diversity 3 and its 50% HVDC variant lead to the greatest savings over the entire modelling period. Diversity 2 and its 50% variant provide the lowest savings relative to the Status Quo over the period. This is due to persistently high capacity margins.

Figure 11: Change in average annual bill



Impacts on security of supply

4.79. NGET's analysis assumes a simple Capacity Market is implemented to reflect the policy intention of the EMR. We consider it appropriate to assume that the EMR work will develop a Capacity Market to continue to ensure security of supply across the modelling horizon.

4.80. We note that there are differences in the EMR assumptions between our Original modelling under the SCR and NGET's approach. These differences are summarised in the reports produced by NGET and Redpoint. These reports have been published in parallel to this consultation.

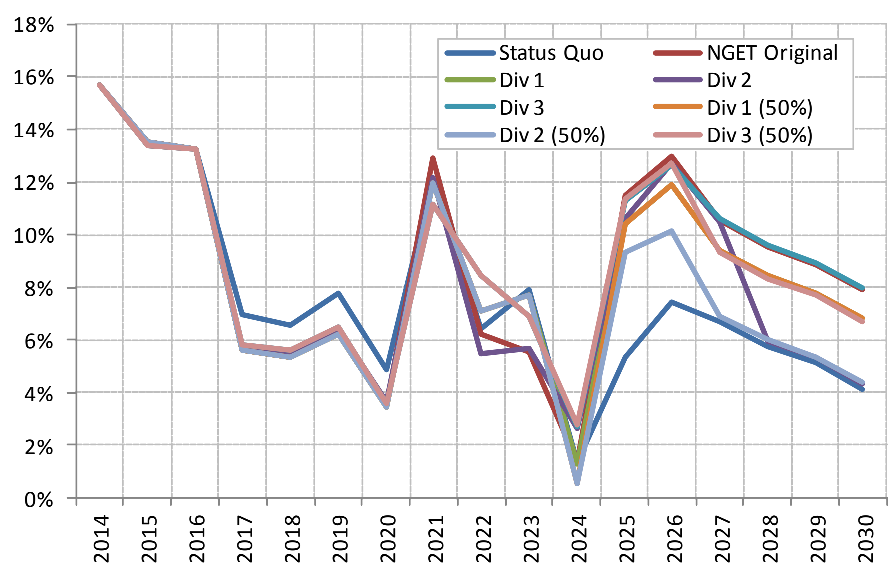
4.81. For the period until 2017, the modelling shows no impact on capacity margins. This is because the impact of changes in transmission charging is assumed to be dominated by other factors, such as LCPD, EMR and commodity prices.

4.82. In the period 2017-2020 de-rated capacity margins under all the modelled charging options are lower compared to the Status Quo. The modelling results of the four main options that seek to better reflect network costs (Original, diversity 1, 2 & 3) produce very similar trends in the period until 2020 relative to the Status Quo.

4.83. The capacity margin is seen to respond strongly in the later modelling period for the four main options relative to the Status Quo, reducing wholesale costs and driving reductions in consumer bills. This is where the highest margins (driven by investment in new nuclear, CCS and CCGT) and also the greatest level of investment in low carbon technologies (which have low, short run marginal costs) are observed.

4.84. In the period 2021-2023 there is significant new CCGT build (~6GW), which along with the development of 5GW of new nuclear allows de-rated capacity margins to recover above 6% under all models. The margins reduce in 2024 due to the closure of certain plant. Margins recover towards the end of the modelling period due to investment in nuclear and CCS. The lowest margins are observed under Diversity 2 and Status Quo due to earlier CCGT retirements in the south.

Figure 12: De-rated capacity margins



4.85. It is worth noting that NGETs modelling of capacity margins for TransmiT differs somewhat in approach from the methodology and assumptions in Ofgem's most recent Capacity Assessment. For example, NGET's most recent demand forecast (reflected in the Capacity Assessment) is lower than earlier forecasts, including that used in the TransmiT modelling. Also, the Capacity Assessment does not assume that a Capacity Market is in place, whereas the NGET modelling for Transmit assumes this is in place from 2018. The approach to de-rating different forms of generation also differs.

4.86. Additional detail can be found in the Redpoint report published alongside this document.

Impacts on sustainability goals

4.87. As part of the modelling, low carbon support levels (ie CfDs) are adjusted to ensure that each charging options delivers broadly the same level of renewable output to meet the same sustainability goals in 2020 (30% renewables output) and 2030 (carbon intensity level of 100 g/kWh). The variation in CfD levels result in variation in the timing and mixture of low carbon investment across modelled charging options, which allows for comparisons to be made.

4.88. Figure 13 and Figure 14 below shows the total renewable generation as a proportion of annual demand and carbon intensity respectively. It is clear that whilst the sustainability goals are met, there is some variation in the timing and mixture of low carbon investment across the model runs. For example, renewable generation is broadly flat after 2020, only increasing up to 33% by 2030. Furthermore, although the runs are closely aligned, the Status Quo run has the highest proportion of renewable generation throughout the modelling period, with Diversity 1 the lowest. Where the same Diversity proposal has been modelled with 100% and 50% converter station costs, there is very little difference between the resulting renewable shares.

4.89. The capacity mixes under Diversity 1 and 2 (and their 50% HVDC variants) are very similar, with the only difference being that Diversity 2 results in an additional 0.8GW of offshore wind capacity, all of which is located in the south. This is because the Diversity 2 generator tariffs are less compressed and more attractive to generation plant in the south.

4.90. The strongest locational tariff differences are observed under Diversity 3, and as a result there is 0.4GW of additional offshore wind (located in the south) compared to Diversity 2 and an additional 1.2GW compared to the Diversity 1 option. There is also an additional 0.4GW of nuclear in the south.

4.91. By 2030 the carbon intensity is the same across all modelled options. However, this carbon intensity is met with a different capacity mix between the Status Quo and options for change - mainly through increased contribution by nuclear and CCS and reduced contribution by onshore wind. This is a result of differences in the relative levels of CfD strike prices for the various low carbon generation technologies.

Figure 13: Renewable generation deployment to meet 2020 target

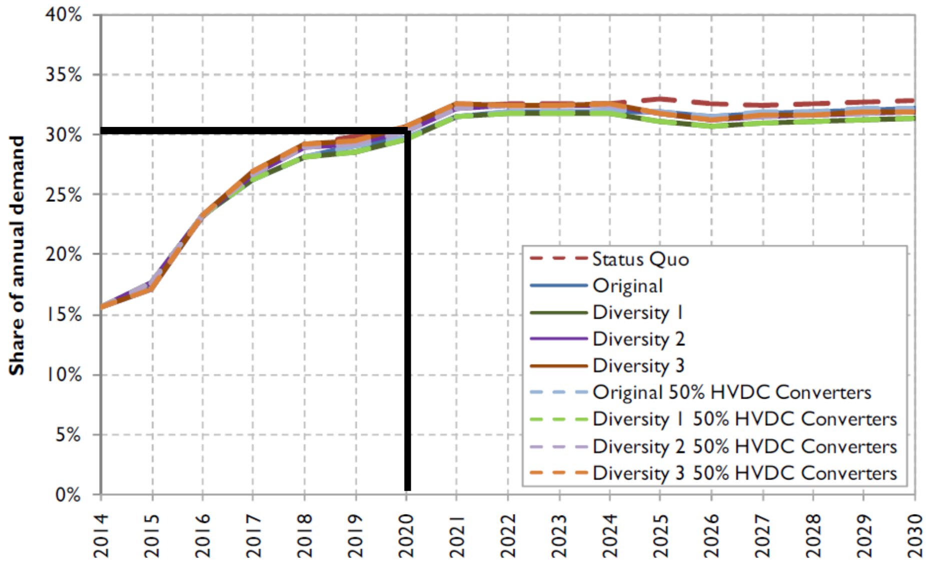
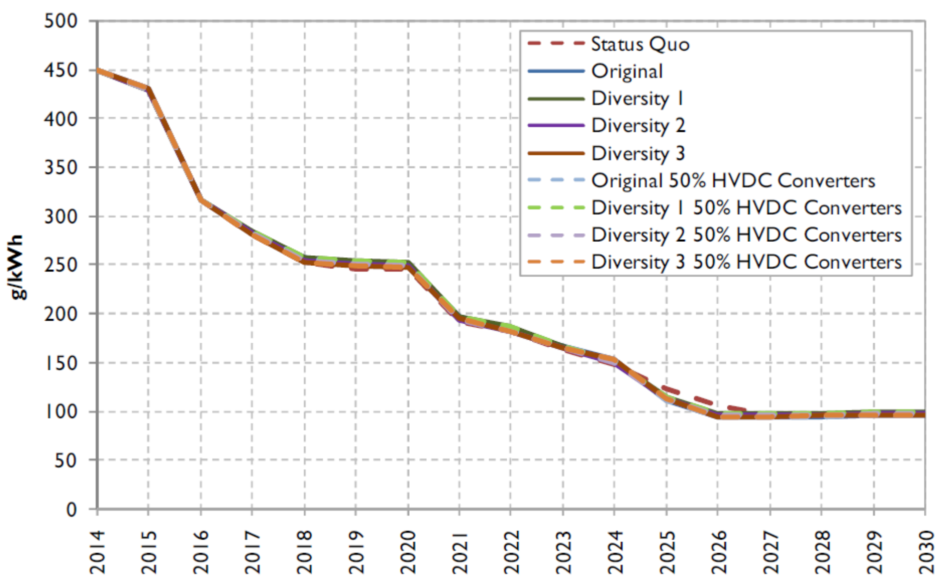


Figure 14: Renewable generation deployment to meet 2030 target



5. Strategic and sustainability considerations

Chapter Summary

This chapter sets out a summary of long term, hard to monetise considerations associated with the Status Quo and the CMP213 alternatives. We also draw out any key differences between the CMP213 proposals

Question box

Question 3: Do you agree with our assessment of the options in terms of the strategic and sustainability impacts? In particular, are there any impacts that we have not identified?

Question 4: Do you think that socialising some of the cost of HVDC converter stations could lead to other wider benefits, such as technology learning? If so, please provide further evidence in this area.

5.1. As part of our decision making process, we have considered how the different CMP213 alternatives contribute to the achievement of sustainable development. Many of the areas traditionally considered under sustainable development are challenging to monetise, making them difficult to incorporate within an aggregate monetised CBA.

5.2. Our previous Impact Assessment as part of the TransmiT SCR contained an assessment of the longer term strategic and sustainability impacts of the options. Our recent consultation on our Impact Assessment Guidance[31] contains a steer as to how we may consider this area in our IAs going forward.

5.3. In qualitatively assessing the effects under each area, we apply:

1. **A stress and security assessment** of the potential implications of the alternatives on:
    a. **Security of supply** failure in electricity and gas supplies, and consideration of the interactions between the two fuel sources where appropriate.
    b. **Potential risk of extreme energy prices and volatility** to a degree which might affect personal security (eg winter deaths), even when the likelihood of these events arising may be very small.
    c. **Risks to the UK's legally binding energy targets**, to ensure that our decisions do not impede the UK's achievement of government targets, and to assess potential contributions of our decisions to these targets.

[31] This is available from our website: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=13&refer=About us/BetterReg/IA

2. **A natural asset and greenhouse gas (GHG) assessment** of potential implications over the longer term (drawing on learning by doing, supply chain development, and pathway dependence and 'lock-in' considerations) on:
    a. **Consistency with the UK's 2050 GHG target**, which is estimated to require a 90% reduction in GHG emissions from the electricity and gas sectors, by assessing the likely impact on CO2 and other GHG emissions;
    b. **Complementary assessment of cumulative GHG emissions implications[32],** which helps reveal optionality and timing implications; and
    c. **Interactions of the energy system with wider environmental assets**, such as biodiversity, landscape, land use, water, air quality and soils, and the ability of the energy system to adapt to a changing climate.

5.4. The rest of this section discusses these areas in relation to the CMP213 alternatives and highlights the differences between them. We have taken the quantitative modelling into account in setting out our considerations in these areas. Security of supply is discussed in Section 6 below.

Potential risk of extreme energy prices and volatility

5.5. NGET's modelling has shown that, overall, Diversity 3 has a marginally higher (~1%) proportion of conventional generation relative to the Status Quo in 2030. However, there is very little difference observed between the Diversity 3 method (and its 50% variant) and the other alternatives modelled. Although it is therefore possible that alternatives based on Diversity 3 are slightly more exposed to fluctuations in gas and coal prices (driven by political, economic and environmental determinants) this difference is unlikely to be material.

5.6. In addition, we would expect there to be less of a difference between the options under a Capacity Market than suggested by the modelling due to the way the Capacity Market was modelled.

5.7. We do not think any of the options represent any material additional risk of extreme energy prices or volatility

Risks to the UK's legally binding energy targets

5.8. NGET's modelling work is sensitive to, and consistent with, all binding decarbonisation and GHG targets to 2030 - all alternatives are consistent with meeting the targets.

5.9. However, the modelling achieves this by varying the strike prices. As such, the alternatives with higher strike prices have a higher risk of not meeting the targets. For example the modelling suggests that Diversity 1 options require lower levels of low carbon support than the Status Quo indicating a lower risk of not meeting the targets. Chapter 6 discusses greenhouse gas emissions for more detail.

[32] We did not identify any impacts in this area

5.10. By reducing tariffs to intermittent generation in northern areas where there is high generation potential targets should be more easily met. More information on the levels of strike prices can be found in the Baringa report.

5.11. We believe that cost reflective charging is important to allow government’s renewable energy support policies to be appropriately assessed to meet the targets in the most efficient way.

Consistency with the UK’s 2050 GHG target

5.12. NGET’s quantitative model did not look at how the different charging options interact with the UK 2050 carbon targets. Whilst a time horizon to 2050 would be optimal, we consider that quantitative modelling in this timeframe would be of limited value, due to the many uncertainties and the potential for further changes to transmission charging in this time period. NGET’s model does not include any terminal value or recognition of the benefits to different options after 2030. Post 2030 considerations are instead discussed here.

5.13. Viewed strategically, it seems likely that delivering the UK’s 2050 GHG target will involve continuing development of the transmission network. This could include the use of more HVDC lines and advanced convertor technologies, that lead to a progressively wider and more meshed system over time. This would allow access to the UK’s extensive renewable energy resources, many of which are more remote or offshore. As such, our expectation is that this would reinforce the net benefit of moving away from the Status Quo so that these investments are appropriately charged for.

5.14. Conceptually[33], the treatment of HVDC converter station costs could have different impacts on the network development and renewable deployment over time. If HVDC converter station costs are partly socialised, this would have the effect of reducing transmission charges to sources utilising the corresponding lines – mainly remote renewable or island generators in the north of Great Britain. This would make the construction of these links more likely to occur.

5.15. A stronger, more resilient transmission network requires more investment, which imposes costs on present and future consumers. However it also delivers benefits which may go beyond immediate point-to-point connections. Enhanced optionality to move power around, and access to more diverse generation sources, would both have the potential to increase the resilience of the system.

5.16. Whilst there does not seem to be a difference in the network built in the modelling between the different alternatives driven by socialising parts of HVDC converter station costs, there may be benefits we have not considered or which have not been captured by the modelling.

5.17. It could also be argued that HVDC converter stations could contribute to other wider benefits in terms of technology learning and cost reductions. Overall, our initial view is that these wider strategic benefits are unlikely to be significant. **However, we welcome further evidence in this area**.

Interactions of the energy system with wider environmental assets

[33] This is not the case in the model but is a possibility either during or after the period the modelling covers.

5.18. We note that onshore infrastructure can often have a greater impact on the environment, in particular visual amenity, than offshore developments.

5.19. Onshore wind in northern GB is likely to gain the most as a result of the more cost reflective tariffs and hence this could have an impact on visual amenity, proposed by CMP213. However, we do not consider the impact of charges alone to be significant since planning procedures and strike prices are likely to be the key drivers in this area.

Overall

5.20. In principle, moving away from the Status Quo to a more cost reflective transmission charging methodology would reduce the cost of deploying intermittent generation and remove barriers to its development.

5.21. In particular we consider NGET's Original, and alternatives featuring Diversity 1 and Diversity 2 methods have the potential for the largest sustainability benefits relative to the current baseline.

5.22. Overall, for these reasons we expect the more cost reflective methodology will mean that the UK can meet its various targets more efficiently or achieve higher levels for the same cost.

6. Assessment against decision making criteria

Chapter Summary

This chapter sets out our assessment against the decision making criteria on the charging options in the light of the initial analysis set out in the preceding chapters. It also contains a discussion on the implementation options.

Question box

Question 5: Do you agree with our assessment of the options against the Relevant CUSC objectives? Please provide evidence to support any differing views.

Question 6: Do you agree with our assessment of the options against our statutory duties? Please provide evidence to support any differing views.

Question 7: Do you agree with our assessment that it is appropriate to implement WACM2 in April 2014? Please provide evidence to support any alternative implementation date.

Overview

6.1. We must consider the merit of any proposed changes to charging methodologies against the relevant code objectives. We have considered the impact of accepting or rejecting the different CMP213 proposals against the existing regulatory arrangements (the current code baseline) as well as relative to each other. Our assessment is summarised in the next section.

6.2. The remainder of this chapter sets out our assessment against the Authority's principal objective and statutory duties. It also provides our views on the appropriate implementation date of any proposals in the event that we decide to implement one of the CMP213 options.

6.3. Our assessment includes consideration of the relevant modelling results, the views of the Panel and the views of respondents to the CUSC Workgroup consultation and CUSC code administrator's consultation and the FMR.

Relevant CUSC objectives

6.4. The relevant CUSC objectives for changes to the Use of System charging methodology are set out in standard condition C5 of National Grid's transmission licence. These are:

a) that compliance with the Use of System charging methodology facilitates effective **competition** in the generation and supply of electricity and (so far as is consistent therewith) facilitates **competition** in the sale, distribution and purchase of electricity;

b) that compliance with the Use of System charging methodology results in charges which **reflect, as far as is reasonably practicable, the costs** (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

c) that, so far as is consistent with sub-paragraphs (a) and (b), the Use of System charging methodology, as far as is reasonably practicable, properly takes account of the **developments** in transmission licensees' transmission businesses.

6.5. The assessment against these objectives is set out in subsequent sections.

Competition – Relevant Objective (a)

6.6. Our assessment of the CMP213 options in relation to competition has included consideration of the following areas:

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

6.7. The principle of cost-reflectivity is based on the economic rationale that, in general, competition is more likely to be effective if costs which parties impose on the system are reflected in the charges they pay and thus are appropriately factored into their commercial decisions. This in turn ensures that the cost of delivery of the required transmission infrastructure is not higher than it needs to be which should benefit consumers. Cost reflective charging is discussed in more detail under relevant objective (b) below.

6.8. To the extent that proposals promote or further cost reflectivity then we must consider whether that benefit to competition is outweighed by any detriments to competition for example by high redistribution effects, barriers to entry or exit or increased complexity.

6.9. It is our initial view that all of the CMP213 proposals are more cost reflective than the Status Quo. Further, to the extent that some of the CMP213 options are more cost reflective that others, our view is that these would more effectively promote competition all else being equal.

Discrimination

6.10. It is important to consider whether the current arrangements or any element of the proposals could be argued to be discriminatory. Discrimination can result not only from treating like cases differently without objective justification, but also from unjustifiably treating different cases alike.

6.11. To the extent that proposals promote or further cost reflectivity, they can be said to reduce the risk of an element of potential discriminatory treatment in the current system. In particular by increasing the extent to which a relevant difference between customers – the costs that they impose on the network – results in differential treatment as between those customers.

6.12. The current methodology could be argued to be discriminatory in a number of respects, including the following:

- It only recognises peak security as a driver of transmission investment – a form of investment that the NETS SQSS assumes is not driven by intermittent plant.
- It does not recognise that transmission investment also takes place to maintain an efficient level of constraint costs (ie year round considerations). Different plants drive different constraint costs and therefore have different impacts on the need for transmission investment. These differences are not reflected in the current methodology as all plants within a generation zone currently pay the same tariff.

6.13. The options presented to us by industry seek to address the above issues:

- NGET's Original has two wider locational tariffs (peak security and Year Round) to reflect the two drivers of network investment. It uses a plant's annual load factor as proxy for its impact on constraint costs and this is multiplied by the Year Round tariff to calculate charges – this is so that charges reflect the different costs by different generators in a zone.
- Diversity 1 builds on the Original by recognising that the relationship between load factor and constraint costs (and ultimately transmission investment) break down where there are high concentrations of low carbon generation.[34]
- Diversity 2 builds on Diversity 1 but includes further adjustments for where there are high concentrations of carbon generation and imposes a cap of the level of sharing of transmission capacity. We do not consider that the evidence supports these adjustments. Please see section below on cost reflectivity for further detail.
- Diversity 3 reverts back to a single tariff (paid by all generators) based on year round considerations. It therefore does not recognise the dual drivers of investment and how different plants contribute to each of them. It also adopts the further adjustments proposed in Diversity 2.

6.14. We recognise that all of these options are approximations of the investment decisions that the TO makes. However, these are the options that have been submitted to us and we consider that they are all an improvement on the existing methodology. Of those options the evidence points to those that feature Diversity 1 being the closest approximation of such decision making. We are therefore of the view that they would reduce the discrimination present in the current charging methodology and, in doing so, would promote effective competition.

Distributional Impacts

6.15. All of the CMP213 options result in a redistribution of costs between generators and to a lesser extent between consumers.

6.16. As can be seen in Chapter 4, under all CMP213 options, zones which currently have high TNUoS charges, such as North Scotland, become more attractive for siting

[34] Some have argued that the means by which this is reflected in Diversity 1, by applying a scalar to load factor where there are high concentrations of non-thermal plant may be a discriminatory oversimplification because some combinations of non-thermal plant type can counter-correlate (eg wind and hydro). However, this ignores the fact that all non-thermal plant, for various reasons, tend to be more expensive to constrain off than thermal plant and it is these costs which drive "Year Round considerations" investment.

plant with lower load factors. Conversely, zones which currently have low positive or negative TNUoS tariffs, such as the south of England, become less attractive for plant with this characteristic. This leads to a redistribution of costs between the south and the north.

6.17. The redistribution from south to north is more pronounced in the options incorporating the NGET Original and Diversity 1 approaches to than under the approaches including Diversity 2. The socialisation of some converter station costs further amplifies this effect. The options incorporating the Diversity 3 approach are much more similar to the Status Quo and therefore have smaller distributional impacts.

6.18. There are also small demand TNUoS differences between regions resulting in small redistribution of costs between consumers from north to south (see Table 7 and Table 8 in Chapter 4).

6.19. Changing/increasing the cost reflectivity of a charging methodology inevitably results in redistribution of costs. Our initial view is that the redistribution of costs is not disproportionately high for any of the CMP213 options and is appropriate in order to improve the cost reflectivity of charges. This is discussed in Chapter 4 (see Figure 4 and Figure 5).

Impact on siting, and entry and exit decision

6.20. In principle, more cost reflective charging methodology should encourage better siting decisions for generation. A methodology that more accurately targets the different costs that generators impose upon the transmission network at different locations should therefore reduce a potential barrier to entry for intermittent generators, particularly in the north of GB whose tariffs at present do not reflect their impact on the network (investment is triggered by their reduced year round operation built in accordance with NETS SQSS principles).

6.21. As described in Chapter 4, modelling results show that the different CMP213 options would likely result in different gas plant retirement decisions. Changes to the charging methodology that increase the number of retirements could negatively impact competition (and thus consumer bills) in the short run since there is a longer lead time for new generators who wish to enter the market. We would expect this impact to be quite small and outweighed by the long term benefits – the modelling that we have undertaken provides some evidence to support this view (see paragraphs 4.68 onwards). We have also considered whether there could be impacts upon security of supply – this is discussed later in the chapter (see paragraphs 6.72 onwards).

Impact on dispatch

6.22. We consider that the effect of the CMP213 options on dispatch is limited to the impact of the hybrid option for calculating the annual load factor of a generator. The hybrid option includes the possibility that generators can forecast their load factor for the year ahead, and the "Year Round" aspect of the wider locational element of a generator's TNUoS charge would be based on the estimated load factor.

6.23. There is some concern that a generator that has inaccurately estimated its load factor could alter its dispatch decisions to avoid the penalties associated with inaccurate estimation. This impact is likely to be most relevant towards the end of the year but will be more significant if the forecast is very inaccurate. Hence, it may generate or refrain from generating against the economics of the plant. This could distort competition in the short term and result in less efficient plant generating instead of more efficient plant so that they avoid any TNUoS penalties. However, the additional complexity inherent in the hybrid option raises other competition concerns as discussed below.

Stability, complexity and predictability

6.24. It is our view that charge volatility, complexity and predictability can affect competition. More stable, predictable charges reduce risk to generators and suppliers. This reduces barriers to entry and makes it easier for smaller generators and suppliers to compete with larger competitors.

6.25. Under all the CMP213 options the charging methodology will be more complex. Diversity 3 (and its variants) produces a simpler set of tariffs relative to the other options and does not rely on an annual load factor calculation for each individual generator. Nonetheless, Diversity 3 also reflects (at a high level) the impact of the generation mix in a zone on the need for transmission capacity (which the current method does not) and would introduce additional complexity.

6.26. The application of a scaling factor (for the Original, Diversity 1 and Diversity 2) based on a generator's average annual load factor, with the highest and lowest values removed, promotes stability of TNUoS tariffs and we consider this is more consistent with a cost reflective signal that is based on long-run incremental costs.

6.27. The hybrid option for calculating the load factor would add additional complexity as it involves some ex ante forecast and an ex post reconciliation, and also require consequential changes to the billing systems to affect the submission and over-recovery payment. Further, we do not think it has been demonstrated that the hybrid approach would deliver any incremental benefit relative to the historical annual load factor approach.

6.28. Overall, we do not consider that any of the CMP213 options will have a significant impact in respect of charging volatility or predictability, although we recognise that the addition of further components in the wider tariff calculation will increase the level of potential volatility relative to the baseline.

6.29. We consider that there are elements of the historical 5 year load factor approach that seek to mitigate the potential for increased volatility of the wider Year Round locational element. For example, it is an average value that discards the highest and lowest annual values, and where insufficient data is available to allow a generic load factor to be developed NGET will use the best information available and agreed with the relevant generator. We consider that these measures may be expected to make the load factor calculation more transparent and less prone to short term volatility.

6.30. Other factors will continue to affect tariffs from year-to-year and we consider the impact of these to be greater than the impact of the change in the methodology. These other factors include:

- changes in the configuration of the transmission network;
- changes to patterns of demand;
- entry and exit by users of the network; and
- the generation zoning criteria.

6.31. In our view, any negative impacts in this area will be outweighed by the improvements in cost reflectivity.

Overall

6.32. Overall, our initial view is that that WACM 2[35] better facilitates Relevant Objective (a). This is because we consider that effective competition is increased since the benefits from the improvement to cost reflectivity reduce discrimination, do not adversely affect siting decisions and are not outweighed by the additional complexity of the TNUoS tariff calculation or disproportionately high redistribution of costs. WACM 2. The historical average annual load factor approach under WACM 2 is also less complex than the proposed hybrid approach. It has the further benefit of not introducing an artificial incentive to ensure annual load factor forecasts are met, which may inappropriately change dispatch decisions.

Cost reflectivity - Relevant Objective (b)

6.33. Our assessment of the CMP213 options in relation to cost reflectivity has included consideration of the following areas:

- Reflecting costs of different users;
- The choice of load factor to reflect "Year Round" considerations; and
- Bootstraps and island links utilising subsea technology.

6.34. We consider that cost reflective charges allow market participants to make efficient commercial decisions about where to locate new generation and when to close existing generation, taking into account the wider costs of these decisions on the network. This therefore assists in the development of an economically efficient transmission system. It in turn facilitates the efficient development of the GB electricity sector which will benefit consumers in due course in the form of lower bills. In order to deliver this we think it is important that the charging methodology reflects the transmission investment decision making process that the TOs follow so that incremental impacts on the need for transmission capacity are appropriately captured.

Reflecting costs of different users

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

6.36. We consider that charges should differentiate between investment driven by peak security and investment driven by year round conditions. The use of a dual background (peak security and year round considerations) in the NGET Original, the alternatives featuring Diversity 1 and Diversity 2 seeks to achieve this. Alternatives featuring Diversity 3 do not include a peak security component to the tariff and do not reflect the different impacts that generators have in driving transmission investment for year round considerations - all generators in a zone get the same

[35] Whilst Diversity 3 and variants is also less complex, we think the approach has serious downsides in terms of cost reflectivity

tariff. As such we consider that alternatives containing Diversity 3 to be less cost reflective than the other approaches that use a dual background (consistent with the investment planning methods of the TOs).

6.37. All the options that use a dual background exempt intermittent generation from the Peak Security element of the tariff. We think this is appropriate as intermittent generators are not relied upon to deliver peak security under the current NETS SQSS. As the peak security tariff methodology is the same across these options our assessment of the relative cost reflectivity of the options depends on how they reflect year round conditions.

6.38. A generator's impact on investment to provide year round capacity depends on its contribution to constraint costs. The Original, Diversity 1 and Diversity 2 options are based (at least as a starting point) on a linear relationship between a plant's load factor and incremental transmission costs. We do not consider this to be an inappropriate approximation based on the analysis set out in the FMR and also think that it is an improvement in terms of cost reflectivity compared to the existing methodology which does not acknowledge this relationship at all.

6.39. The year-round approach in the charging model attempts to use the model to simulate congested conditions across the main transmission boundaries. All CMP213 proposals do this by assuming a uniform level of congestion at all boundaries and at all times of the year. We understand that this is done for two reasons: a) it seeks to represent a long run incremental cost where one would expect to have an optimal balance between constraint costs and transmission capacity, and b) for simplicity. It could be argued that a cost reflective charging solution should seek to reflect that congestion costs are not uniform and incorporate the location of generation relevant to the most constrained boundaries on the system. However, the current methodology does not differentiate in this manner. The CMP213 proposals do seek to differentiate by circuit type (eg the different investment costs) and there is a broad recognition of the economic optimisation approach applied in network planning which we consider to be a positive step providing more accurate cost signals relative to the current baseline.

6.40. In addition, the defects that CMP213 seeks to address is focussed only on improving the long run TNUoS signal which is to recover long term costs of transmission system build as opposed to short term constraint costs on the system. We do not consider the efficient recovery or signalling of short run SO costs (via BSUoS) to be part of the scope of TNUoS charging and therefore is not integral to our CMP213 assessment.

6.41. We consider that alternatives that feature Diversity 1 recognise that intermittent plant in low carbon dominated zones tend to drive more transmission investment. This is because they tend to run simultaneously (eg when the wind is blowing) and therefore cannot "share" transmission network capacity. In addition, they are expensive to constrain off in the Balancing Mechanism (due to the interaction with government renewable energy support policies) compared to other forms of generation. Hence alternatives that feature Diversity 1 are more cost reflective than the NGET Original which does not recognise this.

6.42. Alternatives that feature Diversity 2 also consider both annual load factor and the generation mix. Diversity 2 differs from Diversity 1 in two key respects:

- First, it assumes that high concentrations of carbon generation also do not share transmission capacity and hence drive more transmission investment. It assumes that optimal sharing occurs when there is a 50:50 mix between carbon and low plant behind a transmission boundary.

- Second, it imposes a 50 % cap on the level of sharing. For example, a plant with a 70 % load factor in a zone with a 50:50 generation mix would only see its Year Round tariff component scaled by 85 % (ie the load factor reduction would be halved) rather than 70 % (as under the NGET Original and Diversity 1 options).

6.43. We address each of these points in turn.

6.44. On the first point, we do not consider that high concentrations of low carbon and high carbon/thermal generation have the same impact on the need for transmission investment as assumed by Diversity 2. This is for three reasons:

- We do not think generators with very low load factors behind a boundary with a high concentration of carbon generation will have a significant impact on constraint costs and therefore on transmission costs. Diversity 2 assumes that such a plant would have the same impact on incremental costs as a plant with a very high load factor. There appears to be no reasons as to why this would be and it is not supported by the evidence presented in the FMR[36].
- Low carbon generators' bid prices into the balancing mechanism are higher than those for carbon generators and will therefore trigger a higher level of transmission investment if there are higher concentrations of them.
- Moreover, we consider that the output of low carbon generators (wind in particular) behind a boundary is more likely to be simultaneous (we recognise that might not always be the case, eg for hydro). By contrast, carbon generators are more responsive to levels of demand and will only want to dispatch at the same time when there is an immediate economic incentive to do so. This again suggests to us that high concentrations of carbon generators will not have the same impact on incremental costs as high concentrations of low carbon generators.

6.45. On the second point, there appears to be no clear rationale for the 50 % cap and we have not identified any evidence to support this approach in the FMR.

6.46. Under Diversity 2, the cap basically means that even if a plant has a very low load factor (eg 1%) in a diverse generation area, it would still be deemed to have almost half the impact on incremental costs as a generator with a 100% load factor. We do not think this is a reasonable approximation of the way that transmission investments are considered and we do not think it is consistent with the relationships between incremental costs and load factors presented to us in the FMR. We think that the approach adopted in the NGET Original and alternatives that feature Diversity 1 are more consistent with transmission investment decisions and the evidence presented to us. We therefore consider Diversity 2 to be less cost reflective that the Diversity 1 options.

6.47. As such, it is our view that alternatives that feature Diversity 1 most appropriately reflect the TOs' investment decisions for year round conditions, and therefore are the most cost reflective options.

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[36] as presented in Annex 9 Volume 2

Determining the annual load factor for the "Year Round component"

6.48. In determining the "Year Round considerations" factor we consider that it is important to consider what triggers network investment and hence what a TO assumes a generator will do. The options incorporating the Original, Diversity 1 and Diversity 2 approaches all rely on load factor as a proxy for this. Two alternatives in this regard have been submitted to us: using a 5 year historical annual load factor; or giving users a choice between the 5 year historical annual load factor and a user's own forecast (the hybrid option) which also includes an incentive to forecast accurately.

6.49. We consider that five year historical annual load factor is a good proxy for this based on the evidence provided by NGET (Annex 9 in volume 2 of the FMR). We further consider that removing the maximum and minimum values from this average makes the value less volatile which is what we would expect from a methodology designed to signal long run incremental costs.

6.50. We note that this may not be the case for new generators or those that have changed their generation type eg coal to biomass. However, we consider that the mitigation measures that are proposed within the load factor calculation are appropriate in these cases, ie it is proposed to use generic data until sufficient specific data is available as well as for new and emerging plant types, to use the best information available and the load factor to be agreed with the relevant generator.

6.51. The hybrid option for determining annual load factor could theoretically improve cost reflectivity if it provided a better guide to the incremental transmission costs triggered by a generator but we expect any benefits in this area to be small. Any benefits would rely on plants providing more accurate forecasts to NGET for charging purposes, which generators have previously indicated is a very difficult task[37]. As described above, the hybrid version also introduces complexity and may introduce an incentive to inappropriately change dispatch decisions to avoid penalties associated with inaccurate forecasting.

6.52. On balance, we therefore consider that using the average 5 year historical load factor, rather than the hybrid option, for determining annual load factor is the most proportionate and appropriate.

HVDC links and Island links

6.53. Whilst AC circuits and cables of different voltage levels are included in the current TNUoS methodology, no HVDC subsea technology, outside of the methodology for offshore generator connections[38], is currently taken account of. Similarly, island links are not currently taken account of in the methodology (comprised of subsea AC cables or HVDC technology). We therefore consider that by taking account of HVDC and seeking to allocate the costs accordingly all the CMP213 options are more cost reflective than the current methodology.

6.54. The CMP213 options vary in the proportion of HVDC converter stations costs that are recovered (via the expansion factor calculation which sets the unit cost of

[37] During the TAR process generator's made it clear that they cannot predict the future operation of their asset any better than a TO can – making it necessary for the TO to make assumptions when undertaking the CBA.

[38] 14.15.59 of Section 14 of the CUSC.

using these technologies) through locational charges. We have therefore considered whether it is appropriate remove a proportion of the costs of converter stations in HVDC bootstraps or island links using HVDC technology in the manner proposed in the options submitted to us.

6.55. Removing no HVDC converter station costs from the relevant expansion factor calculation is consistent with the current methodology approach for offshore transmission[39]. Options that treat HVDC converter stations in this manner seek to apply this consistently across bootstraps, island links and offshore transmission utilising this technology.

6.56. However, there is a view that this approach is potentially inconsistent with another aspect of the current methodology onshore. This is because assets that form part of onshore AC substations are not recovered through locational tariffs, ie they are socialised through the residual element of tariffs. Some have therefore argued as part of the industry discussions that it would be consistent to socialise a proportion of converter station costs to reflect the components that are analogous to AC substation costs (eg transformers) or provide similar capabilities as some AC substation components (quadrature boosters).

6.57. Additional arguments were also put forward that Voltage Source Converter (VSC) technology[40] used in some HVDC links (eg the proposed links to the Scottish islands) provides other benefits. Specifically, VSC technology provides very controllable reactive compensation capability, which will benefit the quality of supplies for demand at the remote end of the link. Given these system wide benefits, it could be argued that part of the cost of HVDC converter installations that provide this benefit should be socialised.

6.58. It could also be argued that HVDC installations (ie converter stations in particular) could contribute to other wider benefits in terms of technology learning and cost reductions. As noted in chapter 5 (see paragraph 5.17), we welcome further evidence in this area. Overall, our initial view is that these benefits are not significant.

6.59. Our initial view is that the investment in the HVDC converter stations (including the specific design elements) for bootstrap and island links arise specifically to serve those links and provide the required transmission capacity. Furthermore, our general view is that it is appropriate that costs that are being triggered by users are paid for by those users, to promote cost reflectivity and ensure efficient decisions. We do not consider that the arguments discussed about consistency and other wider benefits are sufficient to support socialising some of the costs. In particular, the modelling undertaken suggests that socialising some of these

[39] Converter station costs at both ends of the cable (and the offshore cable costs) are allocated to the circuit/cable revenue through the expansion factor calculation to determine the locational signal.

[40] Converters are bi-directional, they will change electrical power either from AC to DC or from DC to AC. There are two types of converter: Current Source Converters (CSC) or VSC. With CSC the direction of current cannot be varied, which means that reversal of the direction of power flow (where required) is achieved by reversing the polarity of DC voltage at both stations. VSC maintain a constant polarity of DC voltage and power reversal is achieved instead by reversing the direction of current. The additional controllability of VSC (at either end) improves the harmonic performance and does not rely on local voltage sources in the AC system for its operation. This ability of VSC makes it suitable for connection to weak AC networks, ie the Scottish islands.

costs could increase consumers' bills by far more than the value of any of the benefits identified to date.

Overall

6.60. Overall, our initial view is that WACM 2 better facilitates Relevant Objective (b) since it recognises the generation mix better than the other alternatives and the Status Quo as well as reflecting all HVDC costs to the users who triggered the investment.

Taking account of Developments - Relevant Objective (c)

6.61. The transition to a low carbon economy, along with the changing generation mix this necessitates, and the introduction of HVDC and island links to connect this generation in an efficient manner, constitute changes in the TOs' transmission businesses. We consider that it is appropriate to develop changes to the methodology that seek to ensure that the methodology used to calculates tariffs incorporates these developments in a cost reflective manner.

6.62. We consider that all CMP213 options better achieve relevant objective (c). Of these proposals we consider that WACM 2 is more cost reflective and hence best incorporates the developments of HVDC and island links as well as best taking into account the changing generation mix. As such, we consider that WACM 2 best achieves relevant objective (c).

Overall Assessment of the Relevant CUSC Objectives

6.63. We have assessed the different transmission charging options against the relevant CUSC objectives of competition, cost reflectivity and reflecting developments in the transmission business. Our initial view is that:

- all of the options promote effective competition relative to the Status Quo;
- all of the CMP213 proposals improve cost reflectivity relative to the Status Quo although those that reflect a dual background and recognise the impact of differing generators on TOs' costs are likely to support more effective competition than proposals that do not; and
- all of the options take account of the changing generation mix, HVDC bootstraps and Island links.

6.64. Overall it is our initial view, for the reasons set out in our assessment above, that WACM 2 would best facilitate the achievement of all the relevant objectives relative to the Status Quo and the other CMP213 options.

6.65. The remainder of this chapter sets out our assessment against the Authority's principal objective and statutory duties. It also provides our views on the appropriate implementation date of any proposals.

The Authority's statutory duties

6.66. This section considers whether the different CMP213 proposals better facilitate the Authority's principal objective relative to the Status Quo as well as relative to each other. The Authority's principal objective is to protect the interests of existing and future consumers, wherever appropriate through the promotion of effective competition. These interests include their interests in the reduction of greenhouse gas emissions, security of supply and the requirements of applicable European Law as set out in Article 36(a) of the Electricity Directive.

6.67. The following sections set out our considerations in analysing the impacts of the CMP213 proposals against these duties. This includes:

- The reduction of greenhouse gas emissions
- Security of supply
- Furthering competition
- Consumer bill impacts
- Impact on vulnerable and protected customers
- Impact on health and safety
- Risks and unintended consequences.

Reduction of greenhouse gas emissions

6.68. Transmission charging alone cannot deliver the government's environmental targets. Explicit support from government is also required. Our analysis assumes that DECC's EMR work sets support for low carbon generation to ensure that the binding 2020 renewable target is met under any charging approach. We think this is an appropriate assumption for the purposes of our modelling. The modelling results suggests that all the options are consistent with meeting the 2020 targets and do not present a barrier to their achievement relative to the Status Quo.

6.69. All CMP213 proposals should further promote sustainable development relative to the Status Quo since it is low carbon plant in particular that are currently being inappropriately charged and hence face an undue barrier to entry in some parts of the transmission system where there is significant potential for the deployment of renewables (eg the north of Scotland). This is illustrated by the fact that under all of the options modelled that lower levels of low carbon support are required in order to meet the 2020 targets[41]. In terms of meeting the 2030 decarbonisation target, the modelling suggests that Diversity 1 options also require lower levels of low carbon support than the Status Quo but this pattern is not repeated across the other options.[42] Socialising converter station costs typically reduces the levels of low carbon support required in the models as these charging options tend to favour low carbon generation. The impact of this is fairly small for the Diversity 1 options[43].

6.70. These results suggest that for any given level of CfD support, the options submitted to us have a lower risk to meeting the government's 2020 targets, ie if the same level of low carbon support was set then we would expect the CMP213 options to deliver higher levels of renewable penetration. However, for the 2030 decarbonisation targets only the modelled Diversity 1 options (ie with and without socialising any converter station costs) require less low carbon support. Overall, this

[41] For example, WACM 2 requires £930 million less low carbon support out to 2020.
[42] For example, WACM 2 requires £667 million less low carbon support over the period 2012-2030 whereas the Diversity 3 options require over £1 billion additional support.
[43] It reduces the level of low carbon support by around £40 million out to 2030.

modelling therefore suggests that the Diversity 1 options present the lowest risk to meeting targets associated with reducing greenhouse gas emissions.

6.71. The modelling undertaken suggests that all of the CMP213 options, except for the NGET Original, reduce transmission losses relative to the Status Quo in the long term (ie post 2020). The size of these impacts is relatively small (<£20m per year). Diversity 3 shows the lowest level of transmission losses with Diversity 1 having the second lowest level. The HVDC options do not appear to have any additional effect on the level of transmission losses in the modelling.

Security of supply

6.72. As discussed in Chapter 4 the modelling that has been undertaken suggests that there could be a short term reduction in capacity margins under the CMP213 options in the period 2017-2020 by around 1 percentage point. Our understanding of the modelling, and informed by LCP's review of the model, suggests that this impact could be overstated due to the way that the Capacity Market has been modelled. We would expect that generators would be more forward looking in their decision making than the model suggests and that they would anticipate the introduction of the Capacity Market in 2018 and the additional revenue stream that this would provide. For this reason we would anticipate a smaller impact on capacity margins that the model would suggest. In addition, the modelling does not include the potential impacts of other initiatives (most notably the Capacity Market).

6.73. The assumptions included in NGET's modelling are also somewhat out of date given the time at which the modelling was undertaken. Ofgem's recent Capacity Assessment report provides a more up to date assessment of capacity margins over this decade (for example uses updated demand projections and generator commissioning dates)[44]. Under this analysis, de-rated margins in the Reference Scenario are shown to strongly recover from 2015 and reach around 9 % under by 2017. This suggests that the impact from NGET's modelling is unlikely to be a concern from a security of supply perspective in the Reference Scenario.

6.74. Whilst the modelling does not identify any impact on capacity margins prior to 2017 there is a risk that it could cause a marginal generator to close earlier[45]. However, we do not consider this is likely to present a material risk to security of supply. This is because transmission costs are a relatively small part of a generator's total costs and hence we would consider that a change to charging under CMP213 would be only likely to have an impact on retirement at the margin. The overwhelming drivers of plant retirement decisions over the next few years are LCPD and relative commodity prices (which are currently favouring coal generators).

6.75. Moreover, we note that there are a number of initiatives currently under consideration which focus on improving security of supply, most notably DECC's Capacity Mechanism and, if implemented, Ofgem's proposed reforms of Electricity Cash-Out arrangements. We also note that National Grid and Ofgem both recently consulted on the possibility of National Grid procuring new balancing services[46]. If

[44] See http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%20Report%202013.pdf

[45] we would expect a low load factor gas plant in the south to be potentially most affected

[46] http://www.ofgem.gov.uk/MARKETS/WHLMKTS/EFFSYSTEMOPS/Documents1/Consultation%20on%20the%20potential%20requirement%20for%20new%20balancing%20services%20to%20support%20an%20uncertain%20mid.pdf

proposals for new balancing services are ultimately put forward to Ofgem by National Grid, and are approved by Ofgem, these would, aim to provide extra help for National Grid to balance the system in the face of potentially tightening margins. If changing transmission charging did cause plant to close in the very near term such initiatives could act as a counter-weight to any impact. We would expect any additional cost of these from CMP213 to be small compared to the magnitude of long term benefits that the modelling indicates could be available.

6.76. Based on our initial assessment and for these reasons, we do not consider security of supply to be materially affected by any of the CMP213 options.

Furthering competition

6.77. The impact of the CMP213 options on competition is discussed above in this chapter within the discussion on CUSC Relevant Objective (a). For the reasons set out there, we consider that the WACM 2 option is the most cost reflective option presented to us and best furthers competition. This view is reinforced by the fact that it utilises an average 5 year historical annual load factor which is less complex than the alternative and it also does not distort dispatch decisions by generators which could undermine competition.

Consumer bill impacts

6.78. For any significant change in transmission charges that improved cost reflectivity and competition we would expect the following:

- In the short run, new investment decisions in response to the new charges will have no impact as there are significant lead times for building new transmission and generation. The main impact in the short run is therefore likely to be in terms of some generation plant closing earlier than they might otherwise have done, or some generators delaying plans to decommission.
- In the long run, we would expect investments to be informed by the new more cost reflective charges to result in more efficient decisions in terms of generation siting and transmission build in response to this. We would expect this improved efficiency to result in lower system costs and ultimately for these to be passed through to consumers through the operation of competitive markets in generation and supply.

6.79. The modelling undertaken by NGET and described in Chapter 4 supports the above view. For all the CMP213 options, consumer bills increase between 2014 and 2024 primarily due to increased wholesale prices[47]. After 2024, consumer bills decrease significantly in the model. Taking the period as a whole, consumers are better off. For example, for WACM 2 consumer bills are £0.7 billion higher in the period to 2020 (in NPV terms) and £4.5 billion lower in the period 2021 to 2030. Taking the period as whole this represents a £3.8 billion net benefit to consumers in NPV terms[48]. However, as discussed further in paragraphs 4.10 onwards, we

[47] The increase in wholesale prices is driven by reductions in capacity margins due to earlier retirements of some plant (that benefit from negative TNUoS charges under the Status Quo). The capacity margin is seen to respond strongly in the later modelling period, reducing wholesale costs and driving reductions in consumer bills

[48] NPV numbers are sensitive to modelling assumptions made for example in demand forecasts and way the capacity margin is modelled however we would expect the direction of benefits to remain although the profile of benefits and disbenefits may flatten.

consider that both the short terms costs and the long term benefits could be overestimated by the model. This is because in the short term we would expect:

- fewer plant closures in response to better anticipation of the introduction of the Capacity Market; and
- the impact of updated and lower demand forecasts to result in more inefficient plant to close than in the model which would likely lead to lower wholesale prices due to the lower short run costs of the remaining plant.

6.80. In the long term we might also expect the benefits suggested by the model to be affected. We would expect to see a smaller difference in capacity margins between the options under a Capacity Market and more forward looking behaviour by generators feeding to this mechanism.

6.81. However, whilst we think these estimates are likely to be overestimated, we do not think overall relative magnitude of the figures is likely to be materially affected – even if the long term benefits were halved there would still be a £1.6 billion net benefit to consumers over the period to 2030. This is consistent with our view that a more cost reflective methodology drives a more efficient system in the long run which will deliver consumers benefits.

6.82. We take into account the undesirability of short-term bill increases and the fact that longer term projections are, in general, less reliable than short term projections. We are nonetheless of the view that the long term benefits are likely to outweigh considerably the short term disbenefits as regards consumer bills.

6.83. Recognising that there is to some extent an inevitable trade off between the effects on current and future consumer bills as outlined above, we consider that a more cost reflective methodology, as provided by the Diversity 1 options, is in the long term consumer interest.

Impact on vulnerable and protected customers

6.84. The impact on consumer bills, including impacts on demand tariffs on a regional basis, is discussed in Chapter 4 and is also summarised in the section above (see paragraph 6.78 onwards). Having assessed this evidence, and recognising the issues with the modelling discussed above which might result in the short term costs being overestimated we do not consider that the CMP213 options will have any material specific impact on vulnerable customers.

Impact on health and safety

6.85. We have not identified any health and safety implications related to the CMP213 options.

Best regulatory practice

6.86. The Authority has a duty to have regard to better regulation principles in its decision making. In our assessment we have considered whether the CMP213 proposals are proportionate. In doing so we have considered the distributional effects of the CMP213 proposals (see paragraphs 6.15 onwards). Our initial view is that our preference for a WACM 2 solution is proportionate given the overall aim of eliminating discrimination, promoting greater longer term investment efficiency and the overall benefits to consumers in the longer term from a more efficient system.

6.87. We recognise that NGET's modelling analysis indicates that there may be short term detriments / long term consumer benefits. As discussed above, while we consider the modelling results to provide an accurate description of the relative impact between each of the modelled CMP213 proposals, we think it only provides a broad sense of magnitude of these impacts. This is because of the complex nature of the energy market and the TO's transmission investment decisions. Therefore, we consider the practical need to make simplifying assumptions in the modelling approach is likely to produce results that represent the upper level of cost/consumer impact.

6.88. We discuss below how TransmiT fits within the wider context of European developments which is going in the direction of greater cost reflectivity in transmission pricing more generally. Given this overall direction of travel we consider that the proposals would represent a relatively low risk evolution of the existing approach towards the longer term benefits of improved cost reflectivity suggested by the modelling.

6.89. Consequently, our initial view, for consultation, is that WACM 2 is the right direction for transmission charges.

Risks and unintended consequences

6.90. We have not identified any risks or unintended consequences resulting from the CMP213 options beyond those that have already been discussed elsewhere in this consultation. For example, we discuss risks to security of supply and impacts on consumer bills from the CMP213 options above.

Overall

6.91. It is our initial view, for the reasons set out in our assessment above, that implementing all of the CMP213 options would be consistent with our duties compared to retaining the Status Quo.

European Directives

6.92. We have also considered the modification proposals against the requirements of applicable European law. European legislation does not expressly require either retention of the Status Quo or implementation of any of the proposed options. It does require Ofgem to pursue a number of key objectives aimed at greater European integration. These include promoting cost-effective, secure and efficient network development and avoiding unjustified discrimination (including against renewable generation, particularly in remote locations).

6.93. As discussed above, to the extent that proposals promote or further cost reflectivity, in this case providing for better targeting of costs driven by renewable generators, we consider that they also reduce the scope for discrimination. In addition, we would also expect them to promote more efficient network investment compared to the current arrangements.

6.94. We have also considered the direction of European policy and whether our preference for WACM 2 would align with future changes expected to European policy. We consider that the European direction of travel appears to be towards more cost reflective pricing. As such, we think the WACM 2 option aligns with this trend and represents a relatively low risk evolution of the existing approach.

Implementation Dates

6.95. The implementation date of CUSC Modification Proposals is ultimately decided by the Authority when approving a CUSC change[49]. However, the Workgroup and the CUSC Panel have a role in providing advice and evidence to Ofgem on potential implementation dates. The FMR sets out four broad implementation options

- 'mid year' during the 2013/2014 TNUoS Charging Year;
- 1st April 2014
- 'mid year' during the 2014/2015 TNUoS Charging Year
- 1st April 2015 or beyond

6.96. We have considered a range of suitable implementation dates with the earliest implementation date possible being 1 April 2014. April 2016 was the latest implementation date we considered since a method for bootstraps in the charging methodology needs to be in place ahead of the commissioning of the Western HVDC bootstrap planned for 2016.

6.97. The majority of Panel expressed a preference for implementation in 2015 or later, although there was significant support for April 2014. The reasons for later implementation relate to the desire for a long enough notice period in which to make changes to commercial contracting. The relevant members of the Panel argue that for a change of the magnitude of CMP213 parties should be given a longer implementation time. This, in their view, would avoid creating winners and losers.

6.98. In general, respondents to the industry consultation (and Panel members) who supported implementation of one or more of the CMP213 solutions also supported April 2014 implementation. However, some supportive of CMP213 did request a longer notice period (eg NGET) – for the same reasons given above. Respondents with Scottish generation interests considered implementation should be as early as possible, supporting April 2014 due to the effect of delayed implementation on the whole industry as a whole.

6.99. We recognise that NGET's modelling analysis indicates that there may be reductions towards the end of this decade in the de-rated capacity margin on the system across all CMP213 options. However, our initial view is that we do not think security of supply is materially affected by any of the CMP213 options. This is primarily because our recent capacity assessment report suggests that capacity margins will recover from 2015 and reach a more comfortable level by 2017 when the modelled impact occurs, and that the impact of changes to transmission charging is dominated by developments in energy markets. More detailed reasoning for our thinking on this issue is set out above in the section on security of supply.

6.100. Our initial view is that there is not a strong case to delay implementation of our current preference because of security of supply concerns.

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[49] Section 8.28.3 of the CUSC states that implementation of CUSC modifications to the charging methodologies "may only take effect from 1 April of any given year". However, 8.28.3A states that the Authority may direct a modification of the CUSC in respect of the charging methodologies to take effect from a date other than 1 April by taking into account "the complexity, importance and urgency of the modification".

6.101. Having considered the views of the panel, we have not identified a compelling argument that would suggest that delaying implementation after April 2014 would benefit consumers and better meet our duties. On the contrary, our view is that early implementation is desirable in order to avoid further delay and move quickly in what we consider to be the right direction. This is for the following reasons:

- We consider that the change improves the cost reflectivity of TNUoS charges and addresses defects within the current methodology. In response to the argument put forward that giving more time for implementation would avoid creating winners and losers, we consider that any undue delay in implementation would equally create "winners" and "losers" so we do not see this as a strong argument.
- The longer we leave things as they are, the further away from a more optimal system we will likely become and the higher the upfront impact on industry and consumers will be of making any future change. This suggests that earlier implementation would maximise the available benefits from a change and realise them sooner.
- We note that NGET will produce further updates on the tariffs to apply during 2014/15 throughout the remainder of 2013 and early 2014. The next update is expected from NGET on 1 November 2013 and we would expect this to incorporate our minded to position on CMP213 (if a final decision by the Authority is not available). This will provide greater certainty to market participants of future tariffs. NGET has also indicated that it considers the current default notice period for the publication of final tariffs[50] to be sufficient.
- We recognise that the sensitivity of suppliers to the notice before implementation of any change proposal may be greater than for generation. We also consider that providing an indication of our minded to position and the proposed implementation date will assist users in planning their pricing structures in advance of the next charging year.
- We also note that there are a number of other factors that contribute to the development of TNUoS tariffs and affect the predictability of changes in annual TNUoS tariff levels. NGET will continue to publish information sources on its website to help stakeholders understand potential tariff movements based on developments.
- We are publishing the data sheets of NGET's modelling impact analysis. This includes tariff information from the updated Transport and Tariff models for all modelled options (Status Quo, Original, and all three diversity options). While these are based on last year's 20 generation zones we think they provide a good guide to likely tariffs under the existing 27 zones.
- NGET's analysis of the anticipated tariff movements suggest that the impact on TNUoS tariffs for a thermal generator is within the range of historical changes in tariffs since 2009/10 suggesting that the impact might not be as

[50] CUSC section 3.14.3 requires NGET to provide at least two month advance written notice of any revised charges.

significant in the context of other recent changes that were unrelated to changes in the methodology.

6.102. Our current view therefore is that implementation in April 2014 is most appropriate as it would realise the benefits of an improved methodology sooner and address the defects identified by Project TransmiT as soon as possible.

Our minded-to position

6.103. Our minded to position is therefore to implement WACM 2[51] in April 2014 for the reasoning set out above which we summarise below.

6.104. **We consider that WACM 2 is the option that best facilitates the relevant CUSC objectives.** In summary, this is because we consider:

- It is the most cost reflective option and we would therefore expect it to promote efficient investment decisions. It does this by recognising the two drivers of transmission investment set out in the SQSS and also by taking into account the impact that high concentrations of low carbon plant in an area ultimately have on the efficient level of transmission capacity.
- It facilitates more effective competition by having charges that better reflect the costs that parties impose on the system. This allows these impacts to be factored into commercial decisions within a competitive market for generation. The use of historical load factor, rather than users' forecasts, avoids further complexities to the methodology and also does not distort generators' dispatch decisions which could have a negative impact on competition.
- It better reflects developments in the transmission businesses by taking account of the changing generation mix and the impact that these different users have on the system. It also takes account of HVDC bootstrap links and potential Island links which are not included within the existing methodology.

6.105. **We think that WACM 2 is also consistent with, and is the option that best furthers, our wider duties and our principal objective.** In summary, this is because we consider:

- It is in the best interests of existing and future consumers. While we acknowledge there could be an increase in consumers' bills in the short term, we consider that this will be outweighed by the benefits to future consumers from promoting more efficient long term investment decisions.
- The proposal will not have a material impact on security of supply. There are other factors that we consider to be much more significant drivers of security of supply (eg relative commodity prices, LCPD and EMR policy) and we do not think that this change to transmission charging will be material in this respect. We recognise that there will be a Capacity Market in 2018 (and the potential for new balancing services) which could mitigate any potential short term impact from a change to transmission charges.

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[51] This option incorporates Diversity 1, uses the average 5 year historical annual load factor, and does not remove any costs associated with HVDC converter station costs from the relevant expansion factor calculation based on project specific costs.

- It better meets sustainable development goals. In particular, it better takes account of the impact of renewable generators on the need for transmission capacity. This helps to ensure that transmission charges are not an undue barrier to the deployment of renewable generation that is necessary to meet government targets.
- It is consistent with European legislation and we consider that it is a proportionate means of achieving the benefits referred to above.

6.106. We think that **implementation in April 2014 would realise the benefits of an improved methodology sooner and also address the defects identified by Project TransmiT as soon as possible**.

7. Next steps

7.1. This document marks the start of an eight week consultation period (ending 26 September 2013) during which respondents are invited to provide feedback on our impact assessment and minded-to position. Details on how to respond to this consultation, including contact details for any queries can be found in Appendix 1. It also gives a complete list of the questions which we are specifically seeking respondents’ views on, although we welcome respondents’ views on any aspect of this document.

7.2. We aim to hold a stakeholder event to discuss the consultation and the analysis in late August or early September. We will send an invite to interested stakeholders via our website once we have finalised a date for this.

7.3. The Authority will consider any responses to this consultation before reaching its decision on the CMP213 options. We expect to reach a final decision later in the year.

Appendices

Index

Appendix 1 - Consultation Response and Questions

A1.1 Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

A1.2 We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

A1.3 Responses should be received by Thursday (5pm), 26 September 2013 and should be sent to:

Anthony Mungall, Senior manager transmission policy
Ofgem
107 West Regent Street
Glasgow
G2 2QZ

Tel: 0141 331 6010

Email: Project.transmit@ofgem.gov.uk

A1.4 Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

A1.5 Respondents who wish to have their responses remain confidential should clearly mark the documents to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

CHAPTER: One

There are no questions in this chapter.

CHAPTER: Two

There are no questions in this chapter.

CHAPTER: Three

There are no questions in this chapter.

CHAPTER: Four

Question 1: Do you think we have identified the relevant impacts from NGET's modelling and interpreted them appropriately?

Question 2: Do you have any further evidence of the impacts of the charging options not covered by NGET's analysis?

CHAPTER: Five

Question 3: Do you agree with our assessment of the options in terms of the strategic and sustainability impacts? In particular, are there any impacts that we have not identified?

Question 4: Do you think that socialising some of the cost of HVDC converter stations could lead to other wider benefits, such as technology learning? If so, please provide further evidence in this area.

CHAPTER: Six

Question 5: Do you agree with our assessment of the options against the Relevant CUSC objectives? Please provide evidence to support any differing views.

Question 6: Do you agree with our assessment of the options against our statutory duties? Please provide evidence to support any differing views.

Question 7: Do you agree with our assessment that it is appropriate to implement WACM2 in April 2014? Please provide evidence to support any alternative implementation date.

Appendix 2 – Matrix of CMP213 options

Main components of CMP213	Original	1	2	3	4	5	6	7	9	12	14	16	17	18	19	21	22	23	24	25	26	28	30	31	32	33	40
DIVERSITY																											
Sufficient diversity assumed to exist throughout GB	X	X						X			X					X	X					X					
Diversity method 1			X			X			X	X		X			X			X			X		X			X	X
Diversity method 2				X			X						X						X					X			
Diversity method 3					X									X						X					X		
Load factor assumptions																											
Historical 5 year average	X		X	X				X	X		X	X	X			X		X	X			X	X	X			
YR Forward looking hybrid		X				X	X			X					X		X				X					X	X
HVDC Bootstraps																											
Remove generic proportion of costs (60%)								X	X	X	X	X	X	X	X												
Remove generic proportion of costs (50%)																						X	X	X	X	X	X
Remove specific proportion of costs																X	X	X	X	X	X						
Remove no cost	X	X	X	X	X	X	X																				
HVDC Island links																											
Remove generic proportion of costs (70%)								X	X	X																	X
Remove generic proportion of costs (50%)											X	X	X	X	X							X	X	X	X	X	
Remove specific proportion of costs																X	X	X	X	X	X						
Remove no cost	X	X	X	X	X	X	X																				

Appendix 3 – Reviews of the modelling

A3.1 We have commissioned two pieces of consultancy work to review the updated modelling undertaken by NGET.

Baringa's review of the changes since the SCR

A3.2 We commissioned Baringa (formerly Redpoint Energy) to:

- review changes to the input assumptions and assess the likely impact of these changes;
- review changes made to model functionality, as well as any changes to the mechanistic process underpinning the analytical approach, and assess the likely impact of these changes; and
- compare the outputs of the updated modelling against results produced during the TransmiT SCR and identify the key factors driving potential differences.

A3.3 Baringa's report concluded that the changes made by NGET to the modelling assumptions and functionality for the CMP213 modelling are reasonable and produce results that are consistent with the changes made. In terms of the impact of the changes, Baringa noted that some updates have a significant impact on the results, for example:

- the increase in the total offshore wind capacity by 2020 to reflect the National Grid 2012 Accelerated Growth scenario;
- the increase in total nuclear capacity in (and beyond) 2030, due to increase in nuclear life expectancies; and
- the change to the start date and modelling approach for the Capacity Market.

A3.4 The first two changes above lead to increases in offshore wind and nuclear capacity, which drive most of the changes in power sector costs. Further, Baringa note that the lower capacity margins observed in the CMP213 modelling are also driven by the updates to the retirement dates of existing generation, along with the revised Capacity Market modelling and later start date for the Capacity Market.

A3.5 Baringa also provided a narrative on the results of this modelling which we have published in parallel to this consultation.

Lane, Clark and Peacock's audit of the TransmiT model

A3.6 We appointed Lane, Clark and Peacock (LCP) to carry out a quality assurance review of NGET's modelling work. The primary aim of LCP's review was to assess whether NGET's modelling approach had been implemented correctly. We also asked LCP to provide high level comment on the approach itself. We have published the report produced by LCP in parallel to this consultation.

A3.7 LCP identified a number of minor issues with the implementation of the modelling approach. These included issues that affected the results in some cases, and suggestions to improve the usability of the model.

A3.8 LCP did not think that any of these issues materially affected the conclusions reached from the modelling results. However, it considered that many of the key results are influenced by modelling simplifications and this should be taken into account when drawing any conclusions based on the results of the analysis.

A3.9 LCP did identify an issue with the implementation of alternatives that feature Diversity 3 within the tariff and transport model, which had an impact on modelling results. NGET has since corrected the model in this respect and provided us with updated results. These results are discussed in Chapter 4.

Appendix 4 – Glossary

A

The Authority
Means the Gas and Electricity Markets Authority (GEMA), established by section 1 of the Utilities Act 2000

B

BETTA
the British Electricity Trading and Transmission Arrangements

C

CCGT
Combined Cycle Gas Turbine

CCS
Carbon Capture and Storage

CfD
Contract for Difference. Under a CfD the purchaser (typically an electricity retailer) agrees to purchase a specified physical quantity of energy from the spot market at a set price (the "strike price"). If the actual price paid in the spot market by the purchaser is higher than the strike price, the counterparty to the contract (typically an electricity generator or a financial institution) pays the purchaser the difference in cost. Conversely, if the price paid is lower than the strike price, the purchaser pays the counterparty the difference.

Connect and Manage
Under this regime generators can connect to the transmission network in advance of all the necessary upgrades and reinforcements to the wider transmission system being put in place.

CUSC
Connection and Use of System Code

D

De-rated capacity margin
This is the capacity margin adjusted to take account of the availability of plant, specific to each type of generation technology. It reflects the probable proportion of a source of electricity which is likely to be technically available to generate (even though a company may choose not to utilise this capacity for commercial reasons).

E

Electricity transmission system

The system of high voltage electric lines providing for the bulk transfer of electricity across GB.

ENSG
Electricity Networks Strategy Group www.entsoe.eu

The EU Renewables Directive (Directive 2009/28/EC)
A Directive which mandates levels of renewable energy use within the European Union

G

Gone Green
This is a modelling scenario (not a forecast) designed by National Grid to meet the UK government's legally binding climate change policy targets. Gone Green assumes that the correct economic incentives are in place to make this world a reality.

I

Interconnector
Equipment used to link electricity systems, in particular between two EU Member States

L

LCPD
Large Combustion Plant Directive

M

MITS
Main Integrated Transmission System. A MITS node is defined as being a node with more than four transmission circuits, or two or more transmission circuit and a Grid Supply Point.

N

National Grid Electricity Transmission plc (NGET)
The electricity transmission licensee in England & Wales

O

OFTO
Offshore Transmission Owner

P

Plant margin
This is the amount by which the installed generation capacity exceeds the peak demand, eg peak demand of 100MW and 120MW of installed generation has a 20MW plant margin (20%).

R

RIIO-Transmission Price Control Review 1 (RIIO-T1) The current price control of the electricity and gas transmission network operators, following the TPCR4 rollover. This price control runs from 1 April 2013 to 31 March 2021 and is the first transmission price control review to reflect the new regulatory framework, RIIO (Revenues = Incentives + Innovation + Outputs), resulting from the RPI-X@20 review

S

Strategic investment
Investment in transmission capacity to meet uncertain future requirements

System Operator (SO)
NGET is the System Operator for GB, a role which covers on and offshore networks. Key activities undertaken by the System Operator are real time system operation and system balancing.

SQSS
System Security and Quality of Supply Standards

T

TEC
Transmission Entry Capacity

Third Package
The term 'Third Package' refers to Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC; Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/203; and Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators

TNUoS
Transmission Network Use of System (charge)

Transmission Owner (TO)
Transmission Owner is used to describe the onshore transmission companies, NGET, Scottish Power Transmission and Scottish Hydro Electric Transmission. The use of the term TO in this document only describes the transmission ownership function; NGET also has a system operator function

W
WACMs
Workgroup Alternative CUSC Modifications

Appendix 5 - Feedback Questionnaire

A5.1 Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would particularly welcome your answers to the following questions:

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

A5.2 Please send your comments to: project.transmit@ofgem.gov.uk

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