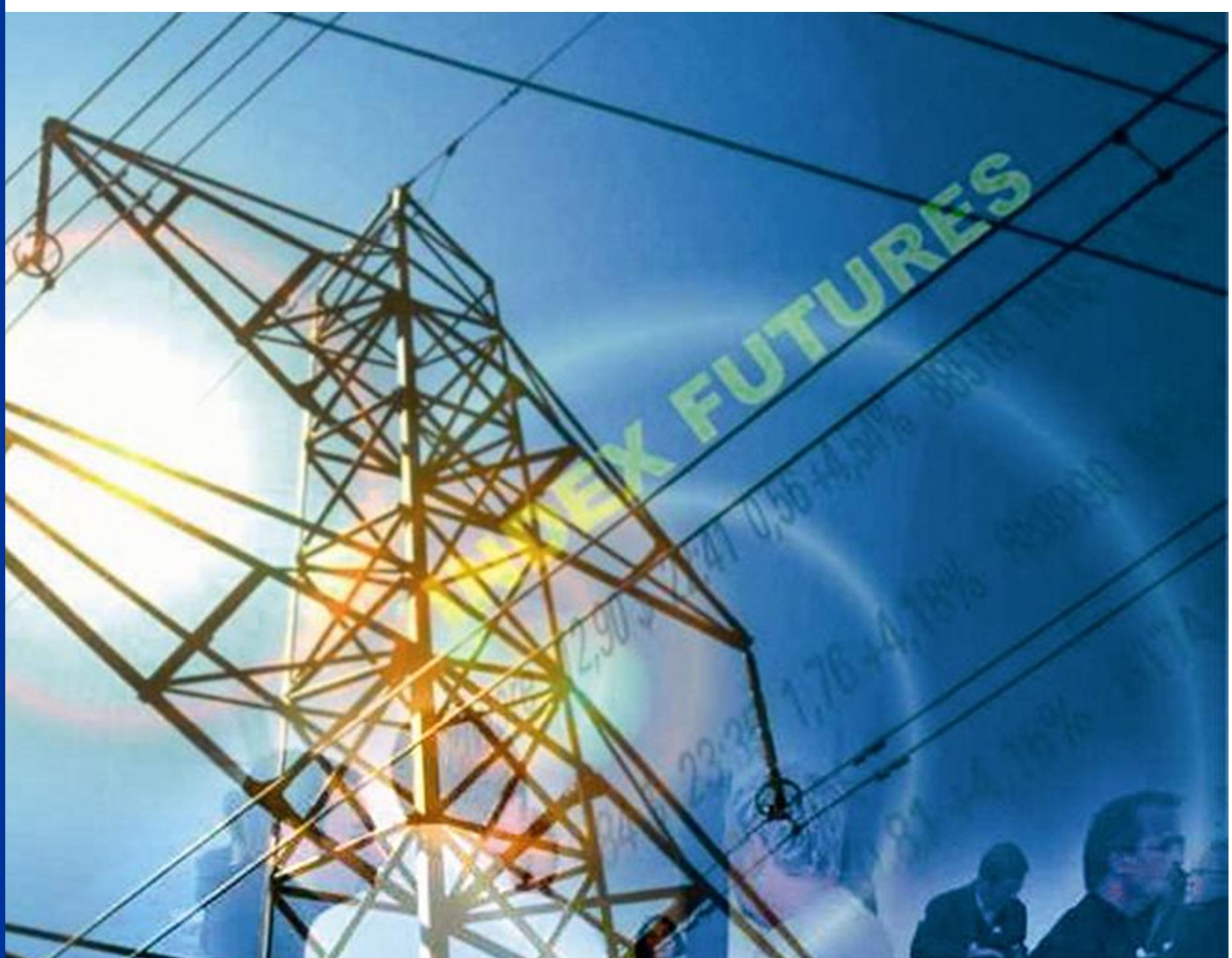
# REVIEW OF OFGEM'S IMPACT ASSESSMENT ON CMP213

A report to Centrica Energy

October 2013

REVIEW OF OFGEM'S IMPACT ASSESSMENT ON CMP213



## Contact details



| Name | Email | Telephone |
|---|---|---|
| Mike Wilks | Mike.wilks@poyry.com | +44 7766 81 279 |



Pöyry is an international consulting and engineering company. We serve clients globally across the energy and industrial sectors and locally in our core markets. We deliver strategic advisory and engineering services, underpinned by strong project implementation capability and expertise. Our focus sectors are power generation, transmission & distribution, forest industry, chemicals & biorefining, mining & metals, transportation, water and real estate sectors. Pöyry has an extensive local office network employing about 7,000 experts. Pöyry's net sales in 2012 were EUR 775 million and the company's shares are quoted on NASDAQ OMX Helsinki (Pöyry PLC: POY1V).

Pöyry Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and other process industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to Europe's energy markets. Our energy team of 200 specialists, located across 14 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

# TABLE OF CONTENTS

# EXECUTIVE SUMMARY

Centrica Energy has commissioned Pöyry to provide expert consultancy support to critique Ofgem's minded to position[1] on the implementation, through CMP213 (WACM 2), of an 'improved ICRP' methodology for GB TNUoS charges including a review of the Impact Assessment of shortlisted CMP213 options.

In particular, Centrica asked us in this **independent report** to consider two aspects of the Impact Assessment published by Ofgem:

- the robustness of the modelling and wider analysis of CMP213 charging options; and
- the appropriateness of proposing implementation of CMP213 WACM2.

## Drivers for reviewing charging TNUoS charging arrangements are valid

CMP213 is predicated on three perceived defects within the current TNUoS charging methodology, identified by Ofgem in Project TransmiT as follows:

- it does not appropriately reflect the costs imposed by different types of generators (in particular renewable generators) on the electricity transmission network as the generation mix evolves;
- it does not reflect the development of High Voltage Direct Current (HVDC) links; and
- it does not take into account potential development of Island links.

We support the need to review the charging methodology to seek to incorporate appropriate treatment for new HVDC and Island links. We also think it is reasonable to consider whether changes in the underlying generation mix necessitate changes to reflect the impact of different generation types on transmission build. However, we do not believe that the proposed methodology is cost reflective or better meets the relevant CUSC objectives and wider statutory duties.

## However the CMP213 Impact Assessment is not robust and the case for adopting CMP213 WACM2 is at best unproven

We see the merits of the proposed approach in relation to the treatment of HVDC convertor stations in relations to bootstraps and Island links. However, we do not consider that a robust case has been made that the proposed revision to the charging background is merited and appropriate, given issues with the modelling within the CMP213 Impact Assessment which mean that it cannot be used in evidence to support the case for change, including:

- modelled scenarios do not provide robust basis for assessment:
  - the status quo baseline includes 100% locational treatment of HVDC and Islands links and so is not the current charging baseline, which clouds any comparison;
  - separate consideration of individual defects in the modelling is absent due to the bundled modelling approach;

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

  - the SQSS investment methodology was not tested within the modelling to verify the suggested cost-reflectivity of the proxy charging methodology options proposed with reference to actual investment decision practices;
- modelling results are not compelling:
  - there is a high range of uncertainty around the calculated marginal overall benefits to end consumers, with potential benefits only accruing after 2024, with increased costs in the first 10 years after suggested implementation; and
  - there is insufficient testing of the modelling results using sensitivities given the number and range of future uncertainties.

## More fundamentally CMP213 WACM2 and the use of ALF is simply not cost reflective of the SQSS and drivers of transmission investment

There are two fundamental issues with the approach for deriving the year-round tariff under CMP213:

- the use of Average Load Factor (ALF) is an inappropriate proxy in TNUoS for SQSS approach to year-round assessment; and
- the CMP213 approach to deriving the year-round tariff is misaligned with the system peak related Economy Background in the GB NETS SQSS.

### *ALF is an inappropriate proxy*

Detailed academic analysis by University of Bath has refuted the assertion that ALF is cost-reflective of drivers of transmission investment. Specifically, the two key conclusions from the University of Bath study provided to the CUSC Working Group, which, in our view, are unduly dismissed, were that:

- employing only two backgrounds within a revised GB TNUoS dual-approach charging methodology under CMP213 would 'fail to create even the crudest representation of system performance and costs' i.e. it was not cost reflective; and
- a consequence of adopting any of the CMP 213 proposals would be 'to increase congestion costs' – which they indicated they felt to be perverse given the objectives of Project TransmiT and CMP213. *This impact was confirmed in the Impact Assessment modelling of CMP213 options.*

The University of Bath study clearly indicates that congestion costs not only vary over time and duration (different backgrounds), but also vary significantly between boundaries. These differences in congestion in terms of magnitude, time and location are not reflected in the CMP213 options assessed and in particular WACM2 which is proposed for implementation.

Therefore, use of ALF is not cost-reflective and arguably discriminatory to those parties adversely financially impacted without benefits to competition.

### *Misalignment with GB NETS SQSS*

The CMP213 approach to deriving the 'year round' tariff is linked to the 'Economy Background' in the GB NETS SQSS which is used for assessing peak driven network investment needs and is not linked to the 'under year round conditions' investment determination methodology in the SQSS[2].

There are five key features of the GB NETS SQSS investment methodology for assessing transmission investment requirements 'under year round conditions', specifically:

- it is forward looking – i.e. it takes a forward view of behaviour and costs;
- it is MW based – i.e. examines the market situation at different time snapshots with different MW levels of demand and available generation capacity;
- it takes account of forecast/assumed planned generation outages which are typically scheduled outside the peak demand months;
- it takes account of forecast/assumed (planned) network outages necessary for maintaining/developing the network which occur outside the peak demand months; and finally
- it considers a range of futures/uncertainties in both physical behaviour of generation and network; and potential costs of operational actions.

However, none of the CMP213 options for deriving the 'year round' tariff incorporate any of these key features. Furthermore, the Impact Assessment does not examine any counterfactual including these key features to verify the proposition/hypothesis that the CMP213 'year round' tariff methodology is cost reflective of the SQSS.

## CMP213 is not demonstrated to better facilitate the achievement of the CUSC objectives and Ofgem's wider statutory duties

Improvements in cost reflectivity are a lynchpin of Ofgem's overall assessment against the CUSC objectives and are considered to outweigh detrimental impacts on competition, such as distributional effects and negative customer impact in the short term. However, the case for improved cost reflectivity, as asserted by Ofgem, is unproven, which erodes the basis for Ofgem's overall assessment. For this reason, we do not believe, on balance, that the assessment demonstrates that WACM2 or the alternatives better facilitate the CUSC objectives, as shown in Table 1.

In addition, Ofgem's assessment against its statutory duties downplays some of the shorter-term negative consequences while placing too much emphasis on possible longer-term upside, in relation to which there is uncertainty. For these reasons, we do not believe that the assessment demonstrates that WACM2 or the alternatives support the delivery of Ofgem's wider statutory duties, as shown in Table 2.

[2] Annex B3 provides extracts from the GB NETS SQSS formal guidance for investment planning under conditions in the course of a year of operation.

**Table 1 – Summary assessment against CUSC objectives**

| Objective | Element | Ofgem view | Pöyry view |
|---|---|---|---|
| Competition | Discrimination | All options (especially WACM 2) reduce discrimination because more cost reflective | The impact upon alleged discrimination is unproven and the proposals arguably introduce discrimination through introduction of ALF |
| | Distributional effects | Distribution from north to south under all options, but justified by greater cost-reflectivity and overall benefits for consumers | The distributional effects are significant and are not given appropriate consideration in the assessment |
| | Impact on generator siting – entry and exit | All options (esp. WACM 2) better reflect drivers of 'forward-looking' TO decisions | The downside effects linked to potential hastened retirement of gas plants and the impact on efficiency of future siting decisions are overlooked |
| | Impact on dispatch | Using 5 years of historical data avoids introducing distortions to dispatch | Historical load factor approach does not entirely remove scope for gaming at the margins |
| | Impact on stability, complexity and predictability of commercial and regulatory arrangements | More complex TNUoS arrangements but justified by greater cost-reflectivity and overall benefits for consumers | Complexity will increase under the revised arrangements, as may volatility |
| Cost reflectivity | Reflecting costs of different users | All options improve cost reflectivity, particularly where move to dual background | Proposals are not shown to be more cost-reflective than the status quo |
| | Choice of LF | Hybrid is theoretically more appealing but hard to implement | Forward-looking factors would be more cost-reflective (but recognise difficult on plant-specific basis) |
| | Bootstraps and island links utilising subsea technology | Options more cost reflective than Status Quo as Status Quo takes no account of HVDC technology for bootstraps and islands | We see merit in the inclusion of HVDC and island links within the methodology as proposed |
| Developments | Changing generation mix | Remedies issue identified in current arrangements | Acknowledge driver for review but unclear that options represent overall improvement |
| | Rules for treatment of island links and bootstrap | Options more cost reflective than Status Quo as Status Quo takes no account of HVDC technology for bootstraps and islands | This issue can be addressed independently of the charging background (and not consistent with modelled version of the SQ) |

Green: Does better facilitate; Amber: Neutral; Red: Does not better facilitate

**Table 2 – Summary assessment against Ofgem's statutory duties**

| Element of assessment | Ofgem view | Pöyry view |
|---|---|---|
| Reduction of greenhouse gas emissions | All options better promote sustainable development primarily because low carbon plant currently being inappropriately charged (barrier to entry) – demonstrated by reduction in low-carbon support | No material benefits in terms of greenhouse gas emissions are shown through the assessment and implications for costs of low carbon support are uncertain given the differences in generation mix between the methodology variants |
| Security of supply | Not materially affected by the CMP213 options | The changes tighten margins in the short-term, with uncertain implications in the long-term |
| Furthering competition | As per CUSC (a) because most cost reflective, and historical load factor not affect dispatch | Negative implications for competition are downplayed and proposals are not shown to be more cost-reflective than the status quo |
| Consumer bill impacts | WACM 2 provides long-term savings in consumer bills that outweigh short-term increases and redistribution | Short-term increases in consumer bills are discounted on the basis of uncertain future reductions |
| Best regulatory practice | Proportionate – distributional effect justified by eliminating discrimination, long term efficiency and lower bills<br>Low risk because European developments support cost reflectivity | Uncertainty regarding longer-term benefits and lack of demonstration of improved cost reflectivity |

Green: Does better facilitate; Amber: Neutral; Red: Does not better facilitate

## P229 precedent is a further argument against CMP213 implementation

The CMP213 Impact Assessment highlights distributional transfers between generators for marginal, if any, consumer benefit. This is similar to the assessment of BSC Modification Proposal P229, which was rejected on the basis of material distributional effects with marginal overall benefit. This sets a precedent for the rejection of CMP213 on the same grounds.

## In summary, Ofgem should reject CMP213 and its alternatives

To take this forward, next steps should be to:

- reject the sharing proposals;
- progress the HVDC and Island link revisions as separate modifications; and
- evaluate any future proposed modifications to the charging background seeking to introduce sharing based on appropriate analysis which robustly assesses potential revisions with reference to the status quo.

[This page is intentionally blank]

# 1. INTRODUCTION

## 1.1 Background

As part of its Project TransmiT process, Ofgem initiated a review of the methodology to derive charges for using the GB transmission network (GB Transmission Network Use of System (TNUoS) charges). The aim of TransmiT is to ensure that appropriate transmission charging arrangements are in place to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure and high quality network services at value for money to existing and future consumers.

In May 2012, following a Significant Code Review process, Ofgem directed National Grid to develop a Modification Proposal to the Connection and Use of System Code (CUSC) to ensure that the TNUoS methodology:

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

In response, National Grid raised a modification, CMP213, in June 2012. A modification report for CMP213 was submitted for Ofgem decision in June 2013, containing National Grid's original proposal and 26 Workgroup Alternative CUSC Modifications (WACMs) proposed by industry.

The 26 alternative options to the Original Proposal consisted of different permutations of treatment of four key design elements, namely

- **Diversity factors** – seeking to reflect the impact of different mix of generation types on the need for transmission investment based on year round (i.e. constraints) considerations. Three different design variants were identified, known as Diversity 1, Diversity 2 and Diversity 3.
- **Load Factors** – adopted on the premise there is a link between load factor of generation plant and transmission investment to address year round constraints issues. Two design variants were used – a 5yr backward looking Average Load Factor (ALF) and a year-ahead forecast approach with ex-post reconciliation ('year forward looking hybrid').
- **HVDC bootstraps** – to recognise these types of transmission assets (e.g. the Western HVDC link). Four design variants were adopted – each removing a proportion of the HVDC bootstrap costs from the locational TNUoS charge element – specifically 60%, 50%, project specific convertor costs, and 0%.
- **Island Links** – to recognise these new types of transmission assets (e.g. Western Isles). Similar to the approach adopted for HVDC bootstraps, four design variants were adopted – each removing a proportion of the HVDC bootstrap costs from the locational TNUoS charge element – specifically 70%, 50%, project specific convertor costs, and 0%.

Full details of these design elements are provided in Annex A.

Within this submission were the recommendations of the CUSC Panel regarding those options Ofgem should consider for implementation. The Panel voted by a majority in favour of 8 of the 27 options – none of which included National Grid's Original CMP213 proposal. These 8 options were alternatives identified under CMP213 Working Group process (known as 'WACMs') 2, 19, 21, 23, 26, 28, 30 and 33, and are summarised in terms of their key features in the table below. For example, WACM 2 features Diversity method 1, using the historical 5 year annual load factor while removing no cost from HVDC bootstraps or Island links.

**Table 3 – Overview of the 8 CMP213 options recommended for consideration by the CUSC Panel**

| | 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 | | | | | | | |

To help with estimating the impact of the changes made to the TNUoS charging methodology under CMP213, Ofgem commissioned National Grid and Baringa to carry out a modelling exercise. National Grid and Baringa have modelled eight of the options for change (as voted by the CUSC Panel as potentially appropriate options) and the status quo in this process.

Furthermore Ofgem commissioned Lane Clark and Peacock LLP (LCP) to undertake in July 2013 a quality assurance of the National Grid/Baringa modelling exercise, reviewing their TransmiT Decision model (TDM), the Transport & Tariff model and an interface spreadsheet to verify (a) these models accurately deployed the subcomponents of the proposed modelling methodology – including checking outputs, (b) each of the modelled CMP213 options were represented correctly, and (c) that model input assumptions were appropriate.

On 1 August 2013, Ofgem published its Impact Assessment in relation to CMP213, which stated that its minded to position was:

- **to approve CMP213 WACM2** – based on the evidence presented (predominantly by National Grid and Baringa) to Ofgem and Ofgem's own analysis, Ofgem considers that this option is consistent with its statutory duties and best meets its principal objective to protect consumers compared to other CMP213 options and the existing GB TNUoS methodology; and
- **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 Ofgem believes that this will ensure the benefits of an improved methodology are realised sooner, the

perceived defects in the methodology are addressed as soon as possible and as Ofgem have not identified a strong reason to delay implementation beyond this date.

Within its Impact Assessment, Ofgem poses the following consultation questions

- 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?
- 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
- 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

In this report we principally focus on addressing Questions 1 and 2 (Section 3 (Q1) and Section 4 (Q1 and Q2)) as part of a critical examination of the quantitative analysis conducted under the CMP213 Impact Assessment; and on addressing Questions 5, 6 and 7 (Section 5) as part of a critical examination of the qualitative/overarching analysis conducted under the CMP213 Impact Assessment.

## 1.2 Purpose of this report and role of Pöyry

Centrica Energy (hereafter Centrica) has commissioned Pöyry Management Consulting (UK) Ltd (hereafter Pöyry) to provide expert consultancy support in relation to critique of Ofgem's minded to position[3] on the implementation, through CMP213 (WACM 2), of an 'improved ICRP' methodology for GB TNUoS charges including a review of the impact assessment of shortlisted CMP213 options.

Pöyry has been actively involved in the evolution of the GB TNUoS charging methodology and has produced two independent published papers on the potential development during the Project TransmiT process for two different clients (EdF Energy[4] and RenewableUK[5]) representing two very different stakeholder interests.

Centrica asked us to consider two aspects of the Impact Assessment published by Ofgem:

---

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

4 'Electricity Transmission Use of System Charging: Theory and Experience. A report to EDF Energy', Pöyry Energy (Oxford) Ltd, November 2010.

5 'Options for GB Electricity Transmission Charging Arrangements. A report to RenewableUK', Pöyry Management Consulting (UK) Ltd, May 2011

- the robustness of the modelling and wider analysis of CMP213 charging options; and
- the appropriateness of proposing implementation of CMP213 WACM2.

This report provides our **independent** view – although it has been discussed with Centrica, we have retained editorial control of the report.

### *1.2.1 Structure of this report*

This concise report reviewing and critiquing the qualitative and quantitative Impact Assessment conducted for CMP213 and Ofgem's resultant proposed option (WACM2) for adoption in the GB TNUoS charging methodology is structured as follows:

- Section 2: Review of the key drivers for reviewing/revising the current GB TNUoS charging methodology arrangements;
- Section 3: Assessment of the robustness of quantitative Impact Assessment modelling results and their use by Ofgem in recommendations for CMP213;
- Section 4: Examination of the cost reflectivity of the charging options considered – in particular against the GB NETS SQSS transmission investment guidance and including re-presenting the key findings from a detailed study conducted by the University of Bath;
- Section 5: Review of the robustness of Ofgem's assessment of the proposed changes to the GB TNUoS charging methodology against the relevant CUSC objectives and wider statutory duties; and
- Section 6: Our summary and conclusions from our review of the CMP213 Impact Assessment.

# 2. DRIVERS FOR REVIEWING THE CURRENT GB TNUOS CHARGING ARRANGEMENTS

## 2.1 Perceived defects

CMP213 is predicated on three perceived defects within the current TNUoS charging methodology, identified by Ofgem in Project TransmiT as follows:

- it does not appropriately reflect the costs imposed by different types of generators (in particular renewable generators) on the electricity transmission network, as 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; and
- 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.

In line with Ofgem's direction CMP213 and its alternatives all seek to address the perceived defects as a bundle.

## 2.2 The need for change

The anticipated HVDC and Island links are new features of the transmission system, with different technological and cost characteristics to existing elements of transmission infrastructure. It is clear that the prevailing TNUoS methodology does not include specific treatment for these assets. As such, there is merit in principle in seeking to modify the methodology to allow for appropriate inclusion and treatment of these assets but while these issues are pertinent for review, the proposed CMP213 methodology has to be proven to be either cost reflective or improves the effectiveness of the methodology against the relevant objectives. In other words, the merits of any proposed solution, as opposed to the overarching concept solely, must be assessed thoroughly. Nevertheless, we see merit in the inclusion of HVDC and island links within the GB TNUoS methodology in an appropriate manner.

The changing generation mix in pursuit of decarbonisation is highlighted as the driver for Ofgem's first perceived defect. In identifying this perceived defect, Ofgem flags the need to ensure that the methodology better reflects the impact of different generation technologies on transmission investment decisions and costs.

In our previous work relating to Project TransmiT for EdF Energy, we outlined our view that the expectation of a much increased level of potentially geographically remote low carbon generation and an associated step-change in network investment, brought into focus the role of the electricity transmission charging arrangements in support of the transition to a decarbonised electricity sector. We considered there to be merit in reviewing the charging methodology to ensure that it is appropriate for the evolving generation mix and developing transmission system. However, we also highlighted that while a review is timely, any review should equally recognise that the existing charging principles as set out in the Connection and Use of System Code (CUSC) remain valid going forward, such that:

- economic and efficient transmission investment remains critical for delivering value to existing and future consumers and it is appropriate for some form of locationally varying charges to be retained in order to promote efficient generation investment decisions and consequential grid development;

- charges should still be based on MW and not MWh, as transmission investment costs will continue to be predominantly driven by capacity requirements and not system utilisation[6]; and
- charging arrangements should be non-discriminatory for all generation classes or within low carbon and high carbon generation classes.

These remain valid principles for transmission charging and the absence of specific methodological changes to reflect the evolving generation mix should not be taken as indication of a defect within the methodology per se. Moreover, since any charging methodology represents a trade-off between competing policy requirements, it follows that lack of any specific changes to it to reflect the evolving generation mix does not mean that the existing methodology is therefore ‘defective’ in the sense that changes to it are an absolute imperative.

A robust case needs to be made to demonstrate that any proposed solution is merited and appropriate (i.e. to mitigate the risk of unintended consequences from making change for change’s sake). In this context, we believe that there are merits in exploring alternatives to simple TEC-based generation TNUoS, subject to robust assessment. In our work for RenewableUK, we considered numerous alternative charging options, two of which are pertinent to CMP213.

The first (referred to as ‘Option 11 – TEC adjusted for technology and location’) introduced adjustments to TEC according to a set of rules about the expected network impact of a generator type in a particular zone. This has parallels with the dual background approach under CMP213. In our qualitative assessment of this approach, we concluded that it could more accurately reflect the impact of generators on transmission network (based on network modelling) but could be complicated to administer, and difficult to understand/implement.

The second (referred to as ‘Option 13 – Energy-based locational TNUoS charges’) replaced existing capacity-based cost signals with charges based on annual metered volumes. This has some parallels with the use of load factor to apportion shared charges under CMP213. Our qualitative assessment of this option concluded that it supports development of renewable generation but poses challenges for cost reflectivity/affordability and predictability of charges year on year.

Our previous thinking on these issues serves to highlight that there are trade-offs to be considered in progressing reforms to the transmission charging methodology. Enhancements seeking to enhance the methodology in one regard may introduce issues elsewhere. Proposed amendments must be assessed in the round and existence of a

---

6 It is worth noting the Florence School of Regulation (FSR) perspective on electricity transmission charging. In January 2012 , the FSR stated that (emphasis added):

‘To increase transparency, the cost components included in electricity transmission tariffs should be harmonized; they should only include costs related to transmission grid infrastructure. Locational signals providing reliable ex-ante signals should be introduced. To avoid a distortion in competition, the EU should fix an average share of the G/L-components; thus, introduce a minimum G-component. The behaviour of grid users in the competitive sector must not be distorted, i.e. transmission tariffs covering the long-term cost of infrastructure should not be calculated based on energy transported (i.e. in €/MWh).’

perceived defect within the methodology should not be taken as justification for progressing changes without appropriate assessment.

In conclusion, we support the need to review the charging methodology to seek to incorporate appropriate treatment for new HVDC and Island links and also to consider whether changes in the underlying generation mix necessitate changes to reflect the impact of different generation types on transmission build.  However, while these issues are pertinent for review, the merits of any proposed solution must be assessed thoroughly under a robust Impact Assessment and proven to improve the effectiveness of the methodology against the relevant CUSC objectives. We do not believe that the proposed methodology is either cost reflective or improves the effectiveness of the methodology against the relevant CUSC objectives, as discussed in Sections 3, 4 and 5 which follow.

[This page is intentionally blank]

# 3. REVIEW OF CMP213 IMPACT ASSESSMENT QUANTITATIVE MODELLING

In this Section, we consider the use of the quantitative modelling in the Ofgem Impact Assessment which supports is recommended methodology change to GB TNUoS (WACM2). We highlight a number of issues specifically related to the following two questions posed by Ofgem in their CMP213 Final Proposals consultation document.

**Q1) Do you think we have identified the relevant impacts from NGET's modelling and interpreted them appropriately?**

Q2) Do you have any further evidence of the impacts of the charging options not covered by NGET's analysis?

Firstly, we think that there are a number of areas in which we would disagree with Ofgem's interpretation and identification of the relevant impacts from the NGET modelling of the different CMP213 options. The modelling issues include:

- range of uncertainty around marginal benefits to end consumers, with benefits only after 2024;
- possible over-estimation of benefits for option(s) favoured by Ofgem – including the interactions with EMR modelling (i.e. capacity mechanism and strike price modelling); and
- insufficient testing of sensitivities given number and range of future uncertainties.

Indeed, our view is that there are so many limitations with the modelling that it cannot be used as evidence to justify change – and this appears to explain its limited use by Ofgem in their overall assessment of CMP213.

In addition some characterised examples we have explored also illustrate some inequities in the cost reflectivity of the CMP213 charging option(s) not brought out in the modelling conducted under the Impact Assessment.

Thus, in the following sections, we examine the robustness of

- CMP213 Impact Assessment conclusions (3.1);
- the modelling methodology (3.2);
- the assessment of options including treatment of uncertainty (3.3);
- Ofgem's use of National Grid's Impact assessment modelling (3.4); and
- Ofgem's interpretation/use of the modelling in its wider assessment (3.5)

We then conclude on the overall quality and robustness of the modelling and related analysis conducted under CMP213, specifically setting out our view that we do not believe the quantitative modelling conducted for the Impact Assessment is robust (3.6).

## 3.1 Robustness of CMP213 Impact Assessment conclusions

Ofgem conclude that Diversity 1 and alternatives represent significant reductions in consumer bills versus the Status Quo. Clearly based on the quantitative modelling based analysis Diversity 3 is shown to be better – in terms of overall benefits to end consumers – than Diversity 1. However, Ofgem in its wider assessment incorporating both qualitative and other over-arching considerations (e.g. in relation to the CUSC objectives for charging), concludes Diversity 1 is the more appropriate/better option to adopt. Review of this Ofgem determination and the link between the quantitative and qualitative analysis are addressed in Section 5.

Thus whilst this assessment considers the quantitative analysis as a whole it does have a particular focus on those aspects relevant to determining the appropriateness of adopting Diversity 1 within CMP213 WACM2.

### *3.1.1 Low $CO_2$ generation assumptions are not sound*

Changes in TNUoS charges are identified as being behind the change in low $CO_2$ generation levels. However, this underestimates the extent to which strike prices also influence low $CO_2$ build. In addition, having different emissions intensities in different scenarios means a comparison is not fully valid. Baringa report that reducing renewable capacity in Status Quo would halve the generation costs savings (of Original).

It may have been possible to come up with a set of strike prices which minimize the consumer costs for each of the options. This would have been a fairer comparison (though we wouldn't claim easy). However, there is no evidence this has been done.

The change in tariff structure (and strike prices) leads to less offshore wind and a little less onshore, though the primary impact seems to be less wind in total (RES penetration down by 1.5% in Diversity 1). Given that the reason offshore wind is built in preference to onshore is higher strike prices this has a somewhat arbitrary feel. It is uncertain in the Status Quo that the strike prices have minimised the cost of low carbon support to achieve the 30% penetration. It would be informative to see the Status Quo run with a slightly lower offshore strike price and slightly higher onshore strike price (and also adjustments to give same CCS Gas). It is possible this would have led to lower costs in the Status Quo. In any case results are very sensitive to the assumed wind merit orders.

Diversity 1 has the highest carbon intensity. As all the low CO2 generation is subsidised it is likely that this is causing the benefits of Diversity 1 to be overstated, and Diversity 3 which had the lowest intensity to be understated. However, the renewable penetration is highest in the Status Quo, so to some extent the faults of diversity 1 also apply to other alternatives. This isn't true of CO2 intensity in that in 2030 some alternatives have a lower CO2 intensity than the Status Quo (though not 2020 where the Status Quo is lowest). However, the disparity between the RES and CO2 numbers is a consequence of lower CCS Gas new build in the Status Quo. Given that CCS Gas the second lowest strike prices (and contributes more to capacity than onshore wind, as well as being easier to build further south) an increase in CCS Gas in the Status Quo may not materially affect consumer costs.

The other issue in terms of the low CO2 build is the high amount of nuclear and CCS capacity assumed (and lack of wind post 2020). We believe both the Nuclear and CCS assumptions are optimistic, and it is unclear why the CCS Coal strike price has been set high enough to encourage so much CCS Coal given it has considerably higher strike prices than everything other than Wave/Tidal. Building less Nuclear/CCS would mean more wind, and also more CCGT as backup. The former may require more network investment post 2020 and the latter provide a greater test of locational incentives for CCGTs.

Another oddity in the Low CO2 generation is there is apparently no solar capacity. While it is true that existing solar (and the overwhelming majority of new solar) is likely to be distribution connected, any new solar will still contribute to the demand profile, so it would have been correct to treat new solar as transmission connected. In any case, the draft

CFD strike prices assume 2.4-3.2GW of large-scale solar by 2020. There is also no explicit mention of Biomass Conversion, though this may be a labelling issue.

### 3.1.2 Capacity Payments and 'Uplift' assumptions and their suggested impacts are questionable

The wholesale price consists of a basic price based on the marginal plant (we suspect taking no account of start-up costs etc.), and an 'uplift', similar in concept to scarcity rent. It has apparently been calibrated based on 2009/10 – numbers seem high, perhaps in part because they include start cost effects. Given margins were high in 2009/10 it is not clear how this has been extrapolated to low margins (and of course the start element doesn't grow much with tightening margins in reality). To provide a sense-check of the high uplift would require a detailed backcasting exercise on scarcity rents. This has not been conducted within the Impact Assessment. It is also worth noting that this modelling was done in ELSI, hence is cruder than it would have been in Pöyry's BID 3 model or Plexos for example.

From 2025 onwards both the capacity payment and uplift are significantly lower in Diversity 1 in comparison to the Status Quo. This would lead to the question of how new entrant CCGTs could be equally profitable in both scenarios. Part of the explanation is that in the Status Quo and Diversity 1 there is no CCGT new entry after 2021. Consequently there is no criterion on later new entrant profitability. It is still possible that the earlier new entry in 2021 is equally profitable, since uplift is marginally higher in Diversity 1 in the period 2021-24, though we have our doubts about this. With 10 year contracts for new entry (if modelled) the capacity payment revenues are hard to assess on the basis on the information in the spreadsheet and pdf documents.

As discussed above, the lack of new build required is largely driven by the high level of nuclear/CCS build in the late 2020s. There is also some sensitivity to assumptions regarding the IED.

The same principles also apply to the Original, Diversity 2 and Diversity 3 (though the last new CCGT in Diversity 3 is 2022 rather than 2021).

Given a lower capacity payment (and to a lesser extent uplift, though the extent to which this effects low load factor plant is unclear) we would have expected more CCGT closures in Diversity 1 and the other alternatives (compared to the Status Quo). This is not the case, but on the basis of the data available we can only say this is counter-intuitive.

Consumer bill impacts are very sensitive to capacity margin profile, due to its effect on the uplift, along with the capacity payment. The reason this doesn't necessarily make earlier new entry inconsistent is the overall NPVs use a 3.5% discount rate, whereas the new entrants would (we assume) require a higher return.

Our view is that it is unlikely that generation plants which are not cleared in the capacity payment auction would stay open (at least for longer than a year or two), so it is unclear how such a range of margins can persist[7]. This suggests the relative benefits of CMP213 options versus the Status Quo are overstated.

---

7 Due to the lumpiness of new build, a certain amount of variation may remain. However, we do not think modelling this would be appropriate, as it is based on coincidences regarding the correspondence between unit sizes and capacity requirements. In any case the variation in margins due to this would be unlikely to be higher than around 1%.

## 3.2 Robustness of CMP213 Impact Assessment modelling methodology and inputs

Having reviewed the robustness of the overall key conclusions arising/taken from the quantitative impact assessment modelling, we now consider:

- Are the inputs appropriate and robust, and given the inputs do the outputs make sense?
- How robust is the QA conducted by LCP?

We present our review of each of these in the following sections.

### *3.2.1 Appropriateness and robustness of the inputs is questionable*

These fall into a number of different categories:

- not show impacts on TNUoS tariffs in new generation zones;
- location of new nuclear/CCS;
- approach to sizing the Eastern HVDC; and
- sharing methodology

#### *3.2.1.1 There is no use of the new charging zones – which will highly impact outcomes*

The analysis does not use the new charging zones, which in moving from 20 zones to 27 will clearly have a substantial impact on the results and findings within the Impact Assessment. There are some reasonably substantial changes, for example the Year-Round element for Argyll changes from 9.07 to 6.92 and the two Lancashire zones are very different. Some of the new small zones with very high year-round may make the build of wind in these zones (including offshore connecting to these zones) more difficult.

#### *3.2.1.2 Location of generation appears selective and favouring certain outcomes*

De-carbonisation post 2020 is mainly achieved through nuclear and CCS. These technologies have flexibility about where they can be built and/or are in good areas of the network from an avoidance of investment perspective.

The proposed sitings of the nuclear also reduce the need for new thermal build in in Southern England/Wales. Out of 11.2GW of new build 10GW is in Southern England. The sites are not listed, but we may assume it includes at least 6.7GW (4 EPRs) at Sizewell and Hinkley Point, which with this amount of nuclear seems likely. Of the other possible sites, it seems unlikely Horizon will build at Oldbury before Wylfa, and Horizon are assuming at least 2.4GW (perhaps as much as 3.8GW) at Wylfa. Therefore it seems that that the additional 3 units in the south must be at Bradwell or Hinkley Point or Sizewell, which are the ideal locations from a transmission perspective. In addition there would be little diversity of ownership. Further build at either Wylfa or Hartlepool or Heysham would have provided a greater test of the transmission system and may have led to a significantly wider zonal spread in tariffs in the longer term.

The lack of CCS new build in Scotland is also noteworthy. While this may be consistent with the TNUoS charges, which still show some spread (given CCS will be exposed to both the year-round and Peak), with the high capital costs of CCS (particularly Coal) the TNUoS represents a relatively small proportion of the levelised cost (much smaller than for a CCGT for example) it isn't clear they have this degree of influence given other cost variations, particularly considering the narrowing range.

#### 3.2.1.3 Oversizing of the Eastern HVDC for the Status Quo overstates CMP213 benefits

We believe the ‘menu-based ‘approach to reinforcement build in ELSI is key driver of ‘over-sized’ Eastern Link in the Status Quo. As a result of this approach the modelling shows that by 2020 constraint costs in CMP213 (in both the Status Quo and Original) collapse to approximately £10million per year from 2020. This implies an imbalance in the trade-off made between the level of constraint costs incurred by National Grid Electricity Trading versus overall spend on network capacity. In other words, we believe the cost of the Eastern Link is overstated in the Status Quo and thus the benefits of CMP213 options overstated in the Impact Assessment. This is important as this is a key value driver for CMP213 options.

It is our view that the impact of a smaller Eastern HVDC link should be modelled to understand the sensitivity of the Eastern link to the constraint costs.

#### 3.2.1.4 For a high wind zone CMP213 unduly favours wind generators

Consider a two zone system, there the smaller zone, A consists almost entirely of wind capacity – say 9.5GW of wind and 0.5GW of inefficient OCGT (a small bit of nuclear/hydro/pumped storage doesn’t change this example much). Under Diversity 1, there would be almost no sharing assumed, and the zone would be an importer for the peak component, so have a negative peak charge. However, with almost no sharing an OCGT would pay nearly as much for the year round as the wind (or indeed a nuclear plant if there was one). However, the OCGT wouldn’t run in practice unless the wind output was low – consequently it is very unfair that it should have to pay high year-round charges. Indeed, in this example zone A would be a very good location for an OCGT (as the negative peak charge would signify a strong need for generation capacity). Whilst this may or may not offset the inappropriate year round tariff – the key point is that for a high wind zone the CMP213 year round tariff is not cost reflective and over-allocates cost to the non-wind generation in the zone.

In this example Diversity 2 is similar to Diversity 1, and under Diversity 3 all capacity pays the same, which is clearly unfair.

In the case of the Original the criticism is different. In a zone with a lot of wind capacity (the majority of the capacity in the zone), with the wind reasonably correlated, that clearly are limits on the amount of sharing – the wind output will be more than the overall load factor a lot of the time (so capacity as a whole for the zone will as well), so the system needs to be capable of coping with far more than wind capacity * ALF.

#### 3.2.1.5 CMP213 options discriminate against load factor generators such as nuclear in favour of wind generators

CMP213 charging options also present potential undue discrimination of wind versus high load factor generator such as nuclear – which is of course zero carbon generation (but also high load factor CCGTs for example) i.e. high load factor generators are allocated overly high costs (and thus tariffs) under CMP213. This is particularly the case for example in Scotland

Consider a two zone example. Zone A is like Scotland, Zone B like England & Wales.

In this example we assume Scotland consists of 5.0GW of wind, 2.4GW of nuclear, 5GW of mid-merit thermal/hydro (i.e. not peaking thermal, PS and Hydro). OCGT capacity is assumed to be negligible. With 1GW of hydro, this makes the low CO2 percentage 68% meaning there would be around 64% sharing.

We then assume the peak demand is 5.5GW and the level of interconnection to England is 3.0GW.

For the peak security, assuming the scaling factor is 75% for the thermal/nuclear, the total output is 5.6GW so there would be 100MW of exports (suggesting small positive numbers for the TNUoS which is indeed what is in the Ofgem document).

For the year round load factors by plant type let's assume 60% for the thermal plants (including pumped storage/hydro for simplicity), 85% for nuclear and 70% for the wind. Then the output is 8.54GW, exceeding the demand plus maximum exports.

Looking at the whole year, more generally the interconnector is constrained when

Wind(A)+Thermal(A)+Nuclear(A)-Demand(A) ≥ 3.0GW

Using the methodology of the SQSS, thermal output will of course be linked to the wind, nuclear and demand. If across both zones there is 10GW of nuclear and 8GW of wind, then:

Thermal(N) = Demand(N)-Nuclear(N)-Wind(N)

So:

Thermal(N) = Demand(N)-8.5-Wind(N)

Assuming Demand(N), where N is national and Wind(N) are proportional to the Scottish values, then

Demand(N) = 10*Demand(A) and Wind(N)=1.6*Wind(A)

Thermal(N) = 10*Demand(A)-8500-1.6*Wind(A)

So the ratio versus the year-round us

(10*Demand(A)-8.5-1.6*Wind(A))/(10*Demand(A,peak)-8.5-1.6*Wind(A,peak))

= (10*Demand(A)-8.5-1.6*Wind(A))/41

So the Interconnector is constrained when

Wind(A)+3.0*(10*Demand(A)-8.5-1.6*Wind(A))/41+Nuclear(A)-Demand(A) ≥ 3.0GW

So:

0.88*Wind(A)-0.27*Demand(A) ≥ 1.56GW

Using average Demand of around 3.7GW, that implies the wind is greater than 2.9GW, i.e. 58% load factor. At the minimum demand (say 1.9GW) the figure is 47%.

Both these load factors are well above the average load factor (even the average winter load factor); hence there would be constraint costs in a small not significant number of periods, all of which have relatively high wind. For the shared element a nuclear plant with an ALF of 90% pays three times as much as a windfarm with a load factor of 30%, despite all the constraints being associated with windier periods. It is true that the wind is not perfectly correlated, so the nuclear should be paying more than the wind, but not by a factor of 3. With 64% sharing the number is a bit less than 3, but still quite high (seems to be around 1.9 based on the proposed 2014/15 charges. While it is true that all the wind isn't perfectly correlated, there is some degree of correlation.

In addition, the ratio of wind and nuclear costs would be still higher in the event that the sharing percentage was higher – particularly if some OCGT capacity were commissioned in Zone A.

While this has looked at nuclear versus wind, it equally applies to a high load factor CCGT. In addition not all wind farms are equally problematic. If one wind farm has a relatively low correlation with wind farms in the rest of the zone, its load factor will typically be lower in periods where the zonal load factor is high (meaning well above seasonal average) so consequently a fair system would mean it paid less transmission charges.

The basic message of this example is that in zones with a lot of wind, which have more issues in the year-round than the peak, then in seems perverse for nuclear at 90% load factor to pay 3 times as much as wind at 30% load factor (in the case of maximum sharing),

In other words in zones with a lot of wind the average load factor of wind in periods where the system is most constrained is well over ALF and a fair system would recognise this and use a better proxy for this load factor. This would make the ratio of cost allocation much lower than the level assumed for wind and high load factor plant using ALF (or other load factor measures) under CMP213. This observation was also made by University of Bath in an earlier independent comprehensive academic study – which we discuss further in Section 4.1.

### *3.2.2 Formal QA by LCP also questions robustness of the modelling*

We have reviewed the QA of the modelling carried out by LCP. Their stated focus is on a detailed review of the modelling engine, rather than the issues around appropriate inputs, use of the results and high-level approach that we highlight in the rest of this chapter.

It is instructive that although LCP broadly approve of the detailed modelling mechanics, they provide caveats in relation to the use of the results with regards to the two output categories (related to EMR) that we discussed previously. For example, noting in Section 6 of the LCP report:

*'In particular, the modelling of EMR will play a fundamental role as the capacity mechanism and Contracts for Difference (CfDs) will, between them, drive the majority of investment decisions in new generation capacity – the CMP213 transmission pricing drivers could therefore easily be 'swamped' by the EMR drivers.'*

Section 6.1 of the LCP report specifically looks at the capacity mechanism modelling and results, starting that:

- 'In particular, when the capacity mechanism is in operation (with the first delivery in winter 2018-19)….we would not expect there to be any fundamental differences between CMP213 options in terms of GB-wide system security'
  - This suggests that any differences between the options can only be in the short-term – i.e. before the operation of the capacity mechanism (although we note the modelling is done on a forward-looking basis). In the short-term, the alternative options worsen security of supply, and hence the overall impact cannot be deemed to be neutral.
- 'Any modelling results that show varying capacity margins are therefore predominantly a reflection of the way that the capacity mechanism has been modelled and should not be seen as a potential advantage or disadvantage of any of the CMP213 options being considered. For this reason we would recommend that the

capacity margin metric is used for model diagnostics only, and not for reporting and analysis.'

  - This therefore reduces the reliance on the consumer bill impacts driven by changes in capacity margins, which is one of the key arguments Ofgem set out in favour of WACM2.

In relation to the modelling of low-carbon generation, Section 6.2 of the LCP report includes the statement:

- 'In updating the strike prices a decision is being made on the composition of the generation mix, e.g. deciding whether to update the onshore wind or offshore wind strike price. As the original strike prices have been chosen to achieve a diverse generation mix, the change in generation mix becomes a modelling assumption rather than an emergent property of the modelling. Any attempt to quantify the change in the build of one technology against another is therefore likely to be swamped by the assumptions made on CfD strike prices.'
  - This therefore weakens any reliance on the use of renewable support costs to differentiate the CMP213 options.

## 3.3 Robustness of assessment of options and uncertain future

Given CMP213 – if nothing else – will have a clear distributional impact for industry stakeholders, it should be expected that the quantitative impact assessment (and also any related qualitative assessment) robustly examine:

- separately the component methodology changes to address the three different perceived GB TNUoS defects identified under Project TransmiT;
- a full range of viable options – including direct reflection of the SQSS approach to year round; and
- the impact on CBA results of different input assumptions reflecting key uncertainties for the period of assessment out to 2030.

Thus we have examined the CMP213 Impact Assessment to review the range of options modelled and the sensitivities to determine the benefits of the dual approach i.e. did the CMP213 options sufficiently consider meaningfully different detailed design variants and under an appropriate range of future market scenarios/sensitivities.

Table 4 describes the nine options modelled, including the status quo, are combinations of different approaches to Sharing, HVDC Links and Island links. There are three approaches to sharing, plus the status quo (which has no sharing) and two approaches to HVDC and Island Links.

**Table 4 – High level description of Status Quo and the eight charging options**

| Charging option[8] | Sharing | HVDC links (% converter station costs in locational charge) | Island links (% converter station costs in locational charge) |
|---|---|---|---|
| Status quo | No sharing on the wider network - as per current methodology | 100% | 100% |
| Original proposal | As per original proposal (ALF) | 100% | 100% |
| Option 2 | Diversity 1 | 100% | 100% |
| Option 3 | Diversity 2 | 100% | 100% |
| Option 4 | Diversity 3 | 100% | 100% |
| Option 28 | As per original proposal | 50% | 50% |
| Option 30 | Diversity 1 | 50% | 50% |
| Option 31 | Diversity 2 | 50% | 50% |
| Option 32 | Diversity 3 | 50% | 50% |

Table 5 highlights the bundling of the solutions to the three perceived defects in the current GB TNUoS charging methodology identified by Ofgem under Project TransmiT.

**Table 5 – Discrepancy between Status Quo definition in qualitative and quantitative assessment**

| Defect identified by Ofgem | SQ – qualitative assessment | SQ – modelling When taken |
|---|---|---|
| Generation TNUoS based on capacity only not cost reflective, as no allowance for sharing | TEC-based | TEC-based |
| No rules for treatment of HVDC convertors for bootstraps | No specific arrangements | 100% locational |
| No rules for treatment of HVDC convertors for bootstraps | No specific arrangements | 100% locational |

8 We note descriptions of these options are set out in Section 14 of the CUSC and in the Draft Legal Text Document for CMP 213.

The modification process should have considered variants that included:

- Status Quo charging background with 100% locational HVDC convertors (this is what was modelled for Status Quo but qualitative assessment not done on this basis), as shown in Table 5; and
- using the NETS SQSS approach directly for economy background with 100% locational HVDC convertors.

## 3.4 Reasonableness of Ofgem's use of National Grid modelling

There is a question as to whether it is reasonable for Ofgem to have continued with the modelling approach developed by National Grid and used by them in the assessment of CMP213.

ELSI reinforcement decisions are based on a comparison of the NPV of potential constraint costs in Y+3 and Y+5. However this approach is not consistent with both SQSS and CMP213 options, as characterised below:

- SQSS: 'Economy Background' based on generic technology factors; and
- CMP213: 'Year' round based on plant-specific annual load factors (hybrid/year-round).

National Grid allow wider range of 'final outcomes' in meeting renewable targets. Baringa report that reducing renewable capacity in Status Quo would halve the generation costs savings (of Original).

In general, we would suggest that the National Grid modelling could have been more rigorous and whilst it is reasonable for Ofgem to use modelling provided/deployed for an impact assessment, equally Ofgem should review the robustness of such modelling.

Furthermore if the modelling is observed to not be as robust and thorough as it should be in the context of the potential impact on stakeholders of a resulting TNUoS charging methodology change. It is not unreasonable to expect Ofgem to seek further and/or improved modelling as part of the Impact Assessment even if this entails a delay to an envisaged timetable.

## 3.5 Ofgem's interpretation and use of the modelling results to support Impact Assessment

We have identified some issues with the interpretation and use of the modelling results to support the Impact Assessment, as summarised in Table 6.

**Table 6 – Interpretation of the modelling results**

| Question | Pöyry view |
|---|---|
| To what extent is the framework for assessment and assessment approach(es) robust? | Very little reliance on quantitative Impact Assessment in overall assessment decision<br><br>Low-carbon build sensitive to 'judgement' on relative changes in strike prices (rather than transmission charges directly)<br><br>Impact of 'lumpiness' of onshore transmission reinforcement (Baringa: 'can favour one option if the reinforcement is close to optimal sizing under that option')<br><br>Consumer bill impacts sensitive to capacity margins, which we do not believe would vary significantly with better modelling[9] |
| Do the conclusions drawn follow the numbers? | Diversity 3 delivers largest reduction in consumer bills, but discarded on qualitative grounds. It also has the lowest CO2 intensity which means benefits may be understated. |
| *How robust is the assessment to uncertainty about future outcomes (both policy and market driven)?* | *Insufficient testing of sensitivities – e.g. availability of other low-carbon options; strike price setting (i.e. moving to more technology neutral) IED decisions; network build delays. There is no evidence of testing Diversity 1 works in extreme (yet plausible) situations* |

The Final Modification Report (1.72) itself says in relation to the Impact Assessment:

- 'the results could not be taken as an absolute comparison between CMP213 options, more rather a possible direction of travel'.

This does not provide a ringing endorsement of the robustness of the quantitative modelling nor an indication that much reliance should be placed on it.

9 Though some variation may remain due to lumpiness of new build, and the difference between load loss based security standards and capacity margins. However, this would be most likely to be of the order of 1% – far less than the range in the analysis.

## 3.6 Final conclusions regarding quality of modelling and robustness of results

Given the array of modelling issues, including the effect of a capacity payment and the variations in low $CO_2$ generation between the various cases (seemingly based on arbitrary adjustments to Strike Prices), we do not believe the case in moving GB TNUoS charging methodology from the Status Quo, to the proposed option(s) under CMP213 is proven based on the modelling.

Indeed, even if it had been proven, the lack of sensitivities (exploring worlds with more wind after 2020 for example, whether that is due to strike price setting methodology, technology development or the level of nuclear/CCS not being realizable) means it would not be clear a new methodology was an improvement in a range of future scenarios and not just this one. For example, the impact assessment may have negative results in scenarios with accelerated closure of southern gas-fired plant or higher Scottish wind rollout

Our view is that there are so many limitations with the modelling that it cannot be used as evidence to justify change – and this appears to explain its limited use by Ofgem in their overall assessment of CMP213.

# 4. COST REFLECTIVITY OF CHARGING OPTIONS

In this Section, we consider the issues around whether the charging approach set out in Diversity 1 is more cost-reflective in principle than the Status Quo. The Impact Assessment does not demonstrate qualitative justification for cost-reflectivity, which is at heart of the assessment set out by Ofgem.

*In fact, the Workgroup report states that the charging approach is more cost reflective than the SQSS, which is not a credible statement, as the SQSS sets the basis for actual transmission investment process and decisions; and the requirement of the charging methodology is that is reasonably cost reflective of this SQSS defined transmission investment process (not anything beyond that on some idealised hypothesis). Otherwise the natural conclusion would be the SQSS is not fit for purposes and/or transmission investment decisions are not being made compliant with the formal SQSS guidance.*

We have identified three key issues relating to the proposed cost-reflectivity of the CMP213 charging options and the proposed adoption of WACM2, specifically:

- A simple Load Factor parameter such as ALF does not reasonably reflect the drivers of network constraints or plant contributions to network constraints.
- The CMP213 'year round' tariff methodology is linked to the SQSS Economy Background methodology but not accurately i.e. it does not reflect it appropriately.
- The CMP213 'year round' tariff methodology is misaligned in that it should be linked to 'under year round conditions' SQSS methodology (the SQSS Economy Background is a peak-driven investment approach) but is not and CMP213 options do not capture any of 5 key features of that SQSS methodology.

Therefore,

1. the use of ALF is not cost-reflective of the drivers of constraints nor the SQSS which determines actual investment decisions; and thus
2. the application of WACM2 is not cost-reflective of the drivers of constraints or the SQSS.

It is thus discriminatory to those parties adversely financially impacted in a context where neither does it provide meaningful overall benefits to end consumers.

This section in particular touches on the following question posed by Ofgem in the consultation document.

**Q2) Do you have any further evidence of the impacts of the charging options not covered by NGET's analysis?**

We would specifically point to the analysis by the University of Bath which highlights that there is weak evidence of link between load factor and incremental constraint costs, and that therefore; the use of ALF does not reflect generators' impact on the transmission network. This is detailed in Section 4.1.

We also highlight inappropriate reflectiveness and misaligned linkage between the CMP213 'year round' tariff methodology and the appropriate SQSS investment methodology for 'year round conditions'. This is detailed in Section 4.2

## 4.1 The use of ALF does not reflect generators' impact on the transmission network

Analysis by the University of Bath highlights that there is weak evidence of link between load factor and incremental constraint costs, and that therefore, the use of ALF does not reflect generators' impact on the transmission network i.e. it is not cost reflective.

Therefore have reviewed the University of Bath, we believe that it makes a sound analytical case demonstrating that ALF is an inappropriate proxy in TNUoS for reflecting the SQSS approach to year-round assessment, and it is based on a more detailed and thorough analysis than that provided to support the reasonableness of adoption of ALF as part of CMP213 options for GB TNUoS charging.

### *4.1.1 Synopsis of the independent academic study by University of Bath*

University of Bath undertook a series of high-level studies based on a representation of the GB transmission system so as to test the basis for the CMP213 proposals. These studies focus on the key driving factors which determine year-round congestion costs. The studies sought to answer three fundamental questions that underpin the network sharing concept.

1. Is it appropriate to assume that load factors can be used to represent a generation technology and its impact on transmission?
2. Is it appropriate to assume a linear relationship between load factors and congestion costs, so that load factor can be used as a proxy for year-round congestion costs?
3. Can a dual background realistically reflect the congestion conditions and thus its costs throughout the year, and in particular are the CMP213 dual-approach options appropriate?

The key findings for each of the three questions arising from the study and the consequent overall conclusions of University of Bath are summarised in the following sections.

#### *4.1.1.1 Appropriateness of load factor to represent generation technology impacts on transmission*

University of Bath's work demonstrates that a generator's load factor is not a fixed parameter, but a highly complex parameter that is shaped by:

- network location;
- network characteristics (in terms of length, capacity, utilisation, congestion across each interconnected boundaries);
- characteristics of generation (such as generation mix, efficiency, controllability, cost curves and output variability);
- characteristics of demand (such as demand duration curves, and demand profiles);
- the direction and utilisation of interconnectors; and
- also market fundamentals.

This is an important result because CMP213 uses a fixed load factor assumption to differentiate generation technologies as a key initial input to deriving charges. These are borrowed from the SQSS and then used to allocate circuits as falling into 'year-round' or 'peak' categories.

The University of Bath study shows that for the same generation technology but with different efficiencies (price), location, and boundary congestion levels, generators will have very different load factors. An example shows that an increase in boundary capacity leads to less congestion resulting in lower cost generation being able to transfer more power thus increasing its load factor, whilst the load factor of the more expensive generation reduces. In the simplified network chosen for the University of Bath study, when the transmission transfer capacity was increased by 25%, the load factor of the cheaper generator increased from 60% to 65%, while the more expensive generator load factor fell from 12% to 5%.

Annual load factor for a generation technology is a variable that is shaped by differing generator and demand parameters and features of the transmission system – for example, as the penetration of intermittent generation increases, the output of conventional generation will change and evolve with it over time. It is thus inappropriate to use the same load factor for a generation technology regardless of its location, efficiencies and market behaviour.

#### *4.1.1.2 The relationship between load factor and year-round congestion costs*

When investigating the possible relationships between year-round congestion cost and annual load factor, University of Bath investigated how a change in wind penetration level, transmission capacity and generation price characteristics might impact load factor and congestion costs.

Their studies demonstrated that under different network, generation and demand conditions the relationship between congestion costs and load factor can vary significantly and that the relationship most certainly cannot be assumed to be linear.

Specifically the University of Bath study showed that load factor is a measure of an average output of a generation technology over the year; whilst congestion cost is sensitive to time (backgrounds), duration elements and boundary locations. The relationship between load factor and congestion cost varies greatly with transmission transfer capabilities, demand profiles and generation mixes, efficiency, controllability and their locations in the system.

The University of Bath study thus concluded it was unsound to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless account is also taken of other factors such as location, efficiency, market conditions, and critically, the network transfer capability.

##### *4.1.1.2.1 Example from CMP213 Sharing Methodology*

There are major flaws in the sharing methodology, particularly in the treatment of very low load factor plant (OCGT) in high wind zones and very high load factor plant (e.g. Nuclear). In addition (though more complicated examples would be required), a CCGT at 30% and windfarm at 30% load factor should be paying the same year-round TNUOS.

Also, not all windfarms are the same. If we take the case of a windfarm in Northern Scotland, this is likely to be better able to share than one in Southern Scotland (in the event major constraint is B6 or further south).

We have investigated, just looking at Scottish windfarms in 2012 how good a proxy load factor are for the effect on constraints.

If we assume windy periods are most likely to cause constraint year-round[10], considering a large subset of BM Unit wind farms, and considering periods where the overall load factor was above 62.5% (chosen since this gives 10% of periods), the average overall load factor was 72% which was 2.6 times the average load factor of 28%.

Looking at the same subset of periods, for individual load factors this ratio was as high as 3.8 (Black Law, though this has an exceptionally low average load factor) and 3.3 (Whitelee).

For other windfarms the ratio was as low as 2.2 (Gordon Bush and Kilbaur), meaning it is likely that Whitelee and Black law contribute disproportionately highly to constraints, whereas Gordon Bush and Kilbaur contribute less than their load factor would suggest. This is intuitively what would be expected, given Gordon Bush and Kilbaur are both in the Scottish Highlands.

#### *4.1.1.3 The appropriateness of the CMP213 dual background approaches*

To examine the validity of introducing a dual background approach into charging as proposed by CMP213, University of Bath developed the concept of a congestion duration curve that charts the variation in the magnitude of congestion costs throughout the year. The objective was to investigate how congestion cost varies in strength and duration, over time and between locations.

The University of Bath study modelled a simplified system that comprised a representation of the B6 and B15 boundaries; the two GB boundaries with the heaviest congestions. The congestion duration curve in Figure 1 below shows that, congestion arises to varying degrees over different time periods.

**Figure 1 – Congestion duration curve from University of Bath study**

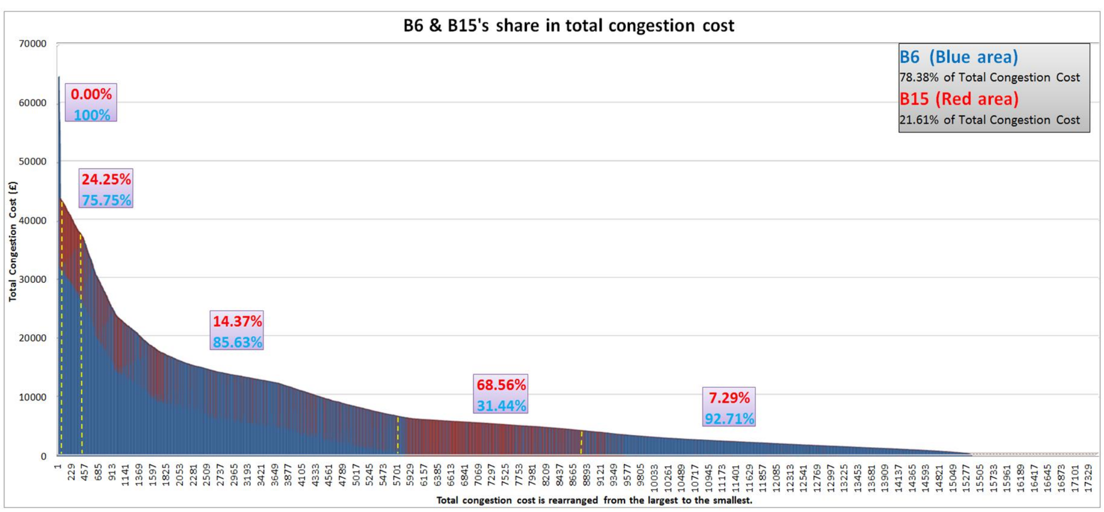



Table 7 below shows that congestion cost is not only linked to the magnitude of congestion, but critically to time, duration and location.

10 Clearly the demand also matters, so this is a bit simplified.

**Table 7 – Congestion costs from University of Bath study for B6 and B15 per segment of duration curve**

| | No. of periods | B6 congestion cost (£m) | B15 congestion cost (£m) | Total congestion cost | Congestion share between the 5 parts | Fraction of B6 in total congestion costs | Fraction of B15 in total congestion costs |
|---|---|---|---|---|---|---|---|
| Part 1 | 23 | 1.3 | 0 | 1.3 | 1.06% | 100.00% | 0.00% |
| Part 2 | 394 | 12.0 | 3.8 | 15.8 | 12.87% | 75.75% | 24.25% |
| Part 3 | 5,427 | 67.4 | 11.3 | 78.7 | 63.91% | 85.63% | 14.37% |
| Part 4 | 3,042 | 4.8 | 10.7 | 15.5 | 12.57% | 31.44% | 68.56% |
| Part 5 | 8,634 | 10.9 | 0.9 | 11.8 | 9.58% | 92.71% | 7.29% |
| Total | 17,520 | 96.5 | 26.6 | 123.1 | 100.00% | 78.38% | 21.62% |

Part 1 of the curve indicates a period of extremely high congestion where costs are in excess of £44k per settlement period. Although of considerable magnitude, this high level of cost is incurred for only 23 settlement periods out of a total of 17,520 in the year. The proportion of the total annual congestion cost in this period is thus relatively small (1.1%), and can for all practical purposes be ignored when approximating the year-round congestion cost. Part 3 of the curve represents the largest share of the year-round congestion costs but still only accounts for 5,427 settlement periods or 31% of the year.

The issue in relation to the CMP213 proposals is that in the original proposals the annual load factor is averaged over the course of the year and consequently its use as a proxy for congestion could severely underestimate the congestion costs over the critical congestion periods; and thus significantly dilute the efficacy of the economic signals.

University of Bath also investigated the most significant periods that contribute to the majority of year-round congestion costs, and how the congestion cost is shared between B6 and B15 boundaries. Their study showed that the periods covering parts 2, 3, and 4 of the congestion duration curve shown in Figure 1 account for 94% of system congestion. They thus concluded that it is these periods that should be adopted as background scenarios for deriving the year-round congestion costs since they display both high magnitude and/or long duration.

Furthermore University of Bath stated that the single 'year-round' condition is flawed in that it does not reflect the difference in magnitude, duration and location of the congestion. Instead they concluded that the CMP213 proposals reflected an extremely high congestion condition that lasts for a very limited duration, and contributes little towards overall system congestion costs.

The University of Bath study clearly indicates that congestion costs not only vary over time and duration (different backgrounds), but also vary significantly between boundaries. The B6 boundary is responsible for over 80% of all system congestion, but this congestion does not occur with the same degree or at the same time across as across the B15 boundary. In fact the B6 and B15 boundaries are only congested simultaneously for 14% of the year. Furthermore congestion across B6, when it occurs, is significantly higher than across B15. This suggests that congestion cost is sensitive not only to time and duration, but more significantly to the location of the boundary.

These differences of congestion in terms of magnitude, time and location are not reflected in the CMP213 options assessed and in particular WACM2 which is proposed for implementation. Employing load factor as a surrogate for the cause of congestion smears the consequence for one boundary across all boundaries and throughout the year. The use of annual load factors in a year-round scenario to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout the year. Thus University of Bath concluded that it cannot provide an appropriate economic message for reducing congestion, and it certainly will not reflect the costs of congestion in accordance with relevant Licence Conditions.

#### *4.1.1.4 University of Bath's key conclusions from its study*

The two key conclusions that University of Bath arrived at from its detailed analytical study were that:

- employing only two backgrounds within an revised GB TNUoS dual-approach charging methodology under CMP213 would 'fail to create even the crudest representation of system performance and costs'; and
- a consequence of adopting any of the CMP 213 proposals would be 'to increase congestion costs' – which they indicated they felt to be perverse given the objectives of Project TransmiT, as confirmed in the Impact Assessment modelling of CMP213 options.

As a result University of Bath recommended that targeting TNUoS charges and credits in periods and locations where generator output contributes to, or relieves congestion would be an improvement to the existing ICRP methodology. They indicated this implies a time of use and congestion location feature in TNUoS charges rather than it being linked to generator annual load factors.

Furthermore University of Bath stated that a TNUoS methodology that related charges to times and boundaries where congestion was most severe would be a significant improvement to the existing methodology. They believed this could be achieved by introducing a time of use element (congestion factor) to the existing peak security based TNUoS charges i.e. the present year-round scenario would be expanded to become a number of scenarios that are directly linked to congestion times and boundaries.

### *4.1.2 Treatment of the University of Bath study by the CUSC Working Group and Ofgem*

The full report of the study conducted by the University of Bath was provided to the CUSC Working Group developing and assessing CMP213 options. We believe, based on the recorded notes of the CUSC Working Group discussions as captured in the CMP213 Impact Assessment documentation that the evidence provided by the University of Bath was inappropriately dismissed by the CUSC Working Group and the CMP213 proposer based on unsound/questionable grounds. The CUSC Working Group's arguments recorded/documented included:

- *There was over-emphasis on constraint costs:*
  However, that is the whole reason for ALF –specifically, the justification for use of ALF is that it reflects year round conditions which leads to transmission constraints which are more economically resolved via transmission investment than ongoing

operational measures – and as such is proposed to be a reasonable proxy for the Economy background approach in the SQSS. Therefore to dismiss the University of Bath study on the grounds it focuses on transmission constraint costs would equally dismiss the point of introducing a 'dual approach' into charging i.e. to introduce a 'year round' aspect under CMP213. You cannot dismiss one without dismissing the other; nor can you accept one without accepting the other.

- *GSR-009 pseudo CBA approach has been extensively developed (but it is not actually used in proposed charging arrangements):*
  Specifically, the suggestion by the CMP213 Working Group is that as GSR-009 has been adopted for the SQSS then the issues raised by the University of Bath study have been addressed. However, this is not the case – the issues have arguably been addressed in the SQSS through adoption of GSR-009 <u>but</u> as this approach has not been adopted within nor accurately reflected by the use of ALF then it clearly has not been addressed within CMP213.

- *Specific load factors of plants are important in differentiating impact of network:*
  However, this is not the approach taken in the GSR-009 pseudo CBA approach in the SQSS – specifically, under GSR-009, the approach is very clearly driven by plant type generalisation of behaviour <u>not</u> (historic) plant specific behaviour. In other words the basis of actual transmission investment planning is <u>not</u> plant specific (and certainly not backward looking), thus it is inappropriate for the CMP213 to go beyond actual practice – as the charging methodology should reflect actual SQSS practice not perceived ideal practice.

On the basis of the above, we believe the study undertaken by University of Bath and its key findings were not appropriately considered by the CUSC Working Group. This is important, as the study was conducted at time in the CMP213 process when its analysis and findings could have been incorporated into identification, development and assessment of alternative options under the CMP213 process.

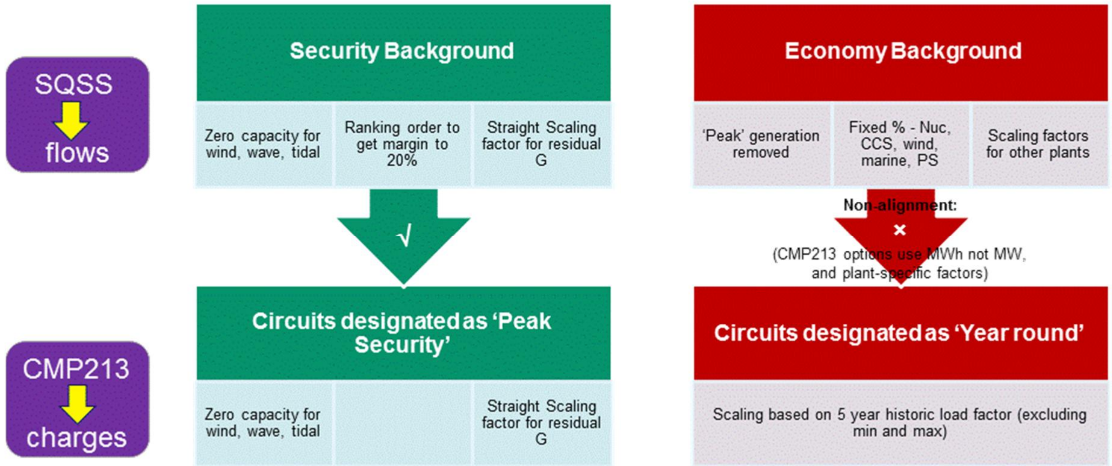
As the study was seemingly effectively dismissed/ignored by the CUSC Working Group, it is not clear whether and to what extent Ofgem considered its findings as part of its overall deliberations on CMP213. For example, there is no record of such consideration by Ofgem in their Impact Assessment consultation – and any reasons for Ofgem choosing to not take account of this study in determining its final proposals in relation to CMP213. Given the detailed nature of the University of Bath study and its findings, it should be expected that Ofgem explicitly address the study in its final proposals document.

## 4.2 CMP213 'year round' tariff methodology is inaccurately linked to the SQSS Economy Background methodology

The fundamental basis put forward by National Grid for adopting CMP213 WACM2 is that it is more cost-reflective of the NETS SQSS[11] than the current GB TNUoS charging methodology. Consequently one would expect the CMP213 Impact assessment to clearly and unequivocally demonstrate/prove that this is the case. However, there is no counterfactual studied exactly reflecting the 'dual background' approach of the SQSS in the tariff methodology to compare with CMP213 options in order to justify the assertion that any of the CMP213 proposals appropriately reflect the 'dual background' approach of the SQSS.A high level illustration of the approach used in WACM2 versus that in the SQSS is described in Figure 2 below:

[11] SQSS (National Electricity Transmission System Security and Quality of Supply Standard – v2.3).

**Figure 2 – Summary of linkage between SQSS and charging in WACM2[12]**




A more detailed exposition of Figure 2 above is provided in Section 4.2.1 (Comparability of SQSS and CMP213 approach to 'Security Background) and Section 4.2.2 (Comparability of SQSS and CMP213 approach to 'Economy Background) below.

In Section 4.2.3 we also outline the 'under year round conditions' approach set out in the SQSS, flagging that CMP213 options for 'year round' do not explicitly link to this in any explicit/direct manner, nor have key features of it been addressed in the CMP213 Impact Assessment.

Full details of the relevant SQSS investment planning methodology is provided in Annex B; and key details of the CMP213-WACM2 methodology as characterised in draft legal text for the Diversity 1 design element is provided in Annex C.

The CMP213 proposals[13] do move to a dual background approach for charging, comparable to the dual background approach set out in the SQSS (as a result of GRS009). However, we believe none of the CMP213 proposals appropriately reflect the 'dual background' approach of the SQSS, particularly because of the use of ALF to calculate the Year Round Transport Tariff paid by each generator. Furthermore, there is no counterfactual studied exactly reflecting the 'dual background' approach of the SQSS in the tariff methodology to compare with CMP213 options in order to justify the assertion that any of the CMP213 proposals appropriately reflect the 'dual background' approach of the SQSS.

The SQSS is used to determine the level of transmission investment required. Section 4.4 of the SQSS describes two background conditions for calculating power flows across the Main Interconnected Transmission System (MITS) – Security Background, and Economy Background. These flows then determine the minimum transmission capacity of the MITS required to satisfy specified requirements; both pre-fault (Section 4.5 of the SQSS) and post-fault (Section 4.6 of the SQSS).

12 Focus here on charging implications for generation (not interconnection)

13 Volume 4 of Final CUSC Modification Report (CMP213 Project TransmiT TNUoS Developments). Draft Legal Text

Therefore, to be cost reflective, the charging methodology should as far as possible:

- accurately reflect the expected investment costs arising from different generation backgrounds; and
- allocate those investment costs to the generators that cause them.

However, the use of ALF to scale the Year-Round Tariff means that this second condition (allocating costs to generators who cause them) is not met in the CMP213 proposals.

### *4.2.1 Comparability of SQSS and CMP213 approach to 'Security Background'*

Table 8 compares the approaches to the 'Security' background in the SQSS and the 'Peak Security' Background in the CMP213 proposals.

**Table 8 – Calculation of flows and charges in Security and Peak Security Backgrounds**

| Steps in Charging Methodology | CMP 213 proposals<br>('Peak Security') | Comparison to SQSS<br>('Security')[14] |
|---|---|---|
| 1) Calculate transmission investment requirements (based on power flows) | Zero capacity for wind, wave and tidal (and for links to external systems)<br><br>Straight Scaling Factor for residual generation so that total generation capacity meets peak demand | Zero capacity for wind, wave and tidal (and for links to external systems)<br><br>If margin >20%, ranking order approach used to remove generation from the calculation<br><br>If margin less than or equal to 20%, Straight Scaling Factor for residual generation so that total generation capacity meets peak demand |
| 2) Allocate circuits to charging background | Circuit tagged as 'Peak Security' if flow on it greater in 'Peak Security' than in 'Year Round' | n/a |
| 3) Allocate circuits to shared and non-shared | No sharing of circuits in Peak Security background | n/a |
| 4) Allocate costs to generators through TNUoS tariff | Transport model used to calculate Initial transport tariffs (ITT) for 'Peak Security' circuits<br><br>ITT multiplied by Peak Security Flag – i.e. zero capacity for wind, wave and tidal; Straight Scaling Factor for all other generation | Scaling factor for charges same as used for calculating flows |

[14] As set out in Appendix C (Modelling of Security Planned Transfer) to the SQSS

It illustrates that the CMP213 proposals broadly follow the same approach to the SQSS- although there is no use of the Ranking Order approach in the CMP213 proposals. This may be because:

- the plants removed in the SQSS are not publicly revealed – and National Grid could not think of a publishable approach; and/or
- those plants removed from the ranking order should then not pay the peak security tariff (to be consistent) which could increase year on year instability in tariffs for a generator if 'in merit' one year and not 'in merit' the next year.

### 4.2.2 Comparability of SQSS and CMP213 approach to 'Economy Background'

Table 9 compares the approaches to the 'Economy' background in the SQSS and the 'Year Round' background in the CMP213 proposals.

**Table 9 – Calculation of flows and charges in Economy and Year Round Backgrounds**

| Steps in Charging Methodology | CMP 213 proposals ('Year Round') | Comparison to SQSS ('Economy') [15] |
|---|---|---|
| 1) Calculate transmission investment requirements (based on power flows) | Peak generation excluded<br>Fixed scaling for:<br>Nuclear: 85%<br>CCS: 85%<br>Wind: 70%<br>Marine: 70%<br>PS: 50%<br>For links importing at time of peak demand: 100%<br>Straight Scaling Factor for residual generation so that total generation capacity meets total national ACS demand | Peak generation excluded<br>Fixed scaling for:<br>Nuclear: 85%<br>CCS: 85%<br>Wind: 70%<br>Marine: 70%<br>PS: 50%<br>For links importing at time of peak demand: 100%<br>Straight Scaling Factor for residual generation so that total generation capacity meets total ACS peak demand |
| 2) Allocate circuits to charging background | Circuit tagged as 'Year Round'' if flow on it greater in 'Year Round' than 'Peak Security' | n/a |
| 3) Allocate circuits to shared and non-shared | Sharing rules vary by Diversity Background | n/a |
| 4) Allocate costs to generators through TNUoS tariff | Transport model used to calculate Initial transport tariffs (ITT) for shared and non-shared Year Round circuits<br>ITT multiplied by plant-specific Annual Load Factor (ALF) | Scaling factor for charges not the same as used for calculating flows (in SQSS or in charging methodology) |

15 As set out in Appendix E (Modelling of Economy Planned Transfer) to the SQSS.

This Table illustrates that the CMP213 proposals broadly follow the same approach to the SQSS in calculating the power flows, but then a different approach is used to allocate the costs to different generators. This undermines the argument that the CMP213 proposals are more cost reflective than the Status Quo because they do not allocate costs in line with the SQSS process – which is forward looking, plant type based and MW based (or indeed with the way in which costs are calculated for charging purposes).

Consequently, WACM2 and the other options are not a better representation of TO decision-making process as:

- constraint costs are driven by coincidence of MW (not annual MWh) – as explicitly recognised in the Economy Background of the SQSS; and
- plant specific information requires backward looking data – whereas the SQSS is a forward-looking process.

Although there was some support in the Workgroup for generic load factors, particularly those based on the SQSS, there was not majority support to take forward any options in which tariffs were scaled by generic load factors.

Indeed, the divergence between the SQSS and the tariff calculation was discussed in the CMP213 Workgroup[16], with the Workgroup noting that:

'4.138 Those in the Workgroup who did not support the use of generic load factor groupings felt that broader generic load factor groupings were less cost reflective than the more granular generic groupings or User specific ALF'.

Furthermore National Grid as the 'Proposer' for CMP213 in its original form is also recorded within the Final CUSC Modification Report (Volume 1)for CMP213 also makes statements to the effect that the CMP213 charging methodology options – in particular the plant specific use of load factors:

'4.103 The Proposer noted that the use of a single pseudo-CBA background had been developed as part of the NETS SQSS work under the change proposal GSR009, and that a significant amount of cost-benefit analysis consideration underpinned the resultant background developed to replicate the year round effect of the National Electricity Transmission System. The Proposer also noted that the rationale for GSR009 was now accepted in the latest version of the NETS SQSS, rather than a proposal as inferred by the Bath University study.

4.104 The Proposer restated that the reason ALF was being used under the Original was that it was a proxy for the effect that a specific generator has on transmission system investment. It was recognised that whilst the generic scaling factors under GSR009 provided a suitable background for assessment, specific generators of a common technology could cause significantly different impacts on transmission investment based on their level of output over a sustained period. Hence, under the Original proposal ALF would be a longer term, plant specific annual load factor rather than by generation type.'

Furthermore in the Final CUSC Modification Report (Volume 2) for CMP213 it states:

4.169 The scaling factors derived in the new NETS SQSS (under GSR-009) and used in the aforementioned two backgrounds were done on the basis of achieving

16 Stage 06: Final CUSC Modification Report – Volume 1 'CMP213 Project TransmiT TNUoS Developments'.

transmission network boundary flows that result in a level of transmission network investment consistent with the outcome of a full blown cost benefit analysis (CBA). It is for this reason that these factors are valid for planning transmission network investment and for use in the Peak Security and Year Round backgrounds when calculating long run network costs in the Transport model.

4.170 Nevertheless, this very approach to calculating the NETS SQSS scaling factors is what potentially makes them inappropriate for calculating an individual generator's contribution to the need for this transmission investment. This is why it is necessary to go back to the original CBA approach upon which the background scaling factors are based, for it is only here that it is possible to investigate an individual generator's contribution to the need for transmission investment to the level of granularity required for cost reflective TNUoS charges (that are non-discriminatory in nature).

In short, National Grid is suggesting that the plant specific approach adopted under CMP213 is more cost reflective than the generator type approach adopted under the GB NETS SQSS. National Grid restated this view at the CMP213 Stakeholder workshop hosted by Ofgem on 6 September 2013. This is not proven - as it has not actually used the exact SQSS methodology as a charging method to test this assertion, nor has National Grid back-cast to see if it would accurately relate to historic transmission investment and its drivers. Indeed the University of Bath study conclusions refute this assertion.

Furthermore, if the SQSS accurately reflects the decision-making of the TO and uses generic load factors only, then using specific load factors cannot be more cost-reflective.

NG argues ALF is required to mimic the actual CBA behind the pseudo-CBA in SQSS. However, this is not required because TOs invest based on the pseudo-CBA set out in the SQSS following GSR-009. Also the University of Bath study shows ALF is not reflecting actual CBA because there is no-relationship between constraint costs and Load Factor and ALF is backwards looking rather than forward looking.

It is also – as a point of principle - not the role of the GB TNUoS charging methodology to seek to be more cost reflective than the SQSS. In other words it is the SQSS which determines the cost reflectivity of GB TNUoS and the GB TNUoS methodology is required to reflect actual TO investment practices - as prescribed in the SQSS. Specifically transmission charging should reflect the process TOs actually adopt to determine investment requirements (worth several billion in RIIO-T1) not an academic hypothesis of what might be better – especially where such a hypothesis is at best unproven and arguably refuted by the University of Bath study.

Consequently in the CMP213 proposals, the calculation of the costs for Year Round Circuit is done on the basis of the generic SQSS scaling factors but the costs are shared on the basis of actual load factors. This means that the plants with lower ALF than generic SQSS load factors (e.g. wind) pay tariffs that underestimate their impact on costs (as defined in the SQSS).

## 4.3 CMP213 'year round' tariff methodology not aligned to 'under year round conditions' SQSS methodology

A puzzling feature of the CMP213 approach to deriving the 'year round' tariff is that it directly links to the 'Economy Background in the GB NETS SQSS – as explicitly stated under Paragraph 14.15.7 in the draft legal text for Diversity 1 presented in Annex C. However, the Economy Background approach outlined in the SQSS is explicitly indicated as a methodology for determining transmission investment at time of peak demand and assuming an intact system (i.e. there are no network outages present).

The SQSS guidance for assessing transmission investment 'under year round conditions' is set out in Paragraphs 4.7-4.10 and Appendix G of the GB NETS SQSS. The explicit purpose of this guidance is to enable economic justification of [non-peak driven] investment in transmission equipment under the overarching condition that:

> *'additional investment in transmission equipment and/or the purchase of services would normally be justified if the net present value of the additional investment and/or service cost are less than the net present value of the expected operational or unreliability cost that would otherwise arise'*

The proposed purpose of introducing the dual approach (i.e. the 'year round' tariff, to complement the current 'peak' tariff) under CMP213 is specifically to address year round conditions and yet there appears to be no direct link to this SQSS methodology in any of the CMP213 options and their development. This suggests a fundamental underlying misalignment of the CMP213 'year round' tariff methodology with the SQSS.

Furthermore, Paragraph 4.7.1 of the GB NETS SQSS clearly states that:

> *'Conditions on the national electricity transmission system shall be set to those which ought reasonably to be foreseen to arise in the course of a year of operation. Such conditions shall include forecast demand cycles, typical power station operating regimes and typical planned outage patterns'*

Whilst key requirements in Appendix G of the GB NETS SQSS include:

> *'due regard should be given to the expected duration of an appropriate range of prevailing conditions….'* and
>
> *'all costs should take account of future uncertainties'*

These guidance statements highlights in particular there are five key features of the SQSS investment methodology for assessing transmission investment requirements 'under year round conditions', specifically:

- it is forward looking – i.e. it takes a forward view of behaviour and costs;
- it is MW based – i.e. examines the market situation at different time snapshots;
- it takes account of (planned) generation outages – i.e. the impact of forecast/assumed generation outages is a key element of the assessment;
- it takes account of a non-intact network – i.e. the impact of forecast/assumed (planned) network outages is a key element of the assessment; and finally
- it considers a range of futures/uncertainties – i.e. both uncertainties in physical behaviour and cost behaviour need to be addressed.

None of the CMP213 options for deriving the 'year round' tariff incorporates any of these key features. Furthermore the Impact Assessment does not examine any counterfactual including these key features to verify the proposition/hypothesis that the CMP213 'year round' methodology is cost reflective of the SQSS.

## 4.4 CMP213 approaches are not cost-reflective of the SQSS

As Figure 2 above highlights, for peak conditions, the current GB TNUoS charging methodology and the options being considered under CMP213 broadly and we believe reasonably reflects the investment methodology prescribed in the GB NETS SQSS.

However, it is equally clear from Figure 2 and particularly Table 9 above that, for 'year round' conditions there is very limited commonality between the options being considered under CMP213 and the investment methodology prescribed in the GB NETS SQSS. In particular the use of a backward looking MWh based approach under CMP213 options is not compatible with the forward looking MW based approach adopted in SQSS.

The only possible acceptable rationale therefore for adopting the CMP213 'year round' methodology treatment would be it were proven to provide a reasonable cost-reflective proxy for the methodology in the GB NETS SQSS. However, given no CMP213 option directly reflecting the NETS SQSS 'year round' approach has been assessed (or used as a benchmark for comparison of cost reflectivity), nor has any quantitative assessment been conducted to test the CMP213 methodology against historic investment decisions there is no robust quantitative analysis in the CMP213 Impact Assessment to prove this assertion. Moreover, as discussed in Section 4.1, the University of Bath study clearly demonstrated that in fact the CMP213 approaches – including specifically their use of LF or ALF – are not cost reflective and thus are NOT a reasonable proxy for the SQSS.

# 5. ASSESSMENT AGAINST WIDER CODIFIED OBJECTIVES

## 5.1 Overview

As outlined in the previous Sections, CMP213 focuses on three areas of reform to the transmission charging arrangements:

- reflecting 'peak security' and 'year round' drivers for transmission investment;
- taking account of HVDC links; and
- taking account of island links.

Our prime focus in this Section is on the proposed dual background approach component, intended to reflect the impact of different types of generators on the transmission system. Specifically, we consider Ofgem's assessment of WACM 2 against the relevant objectives.

While our focus is on the dual approach aspect of CMP213, in principle, we see merit in the inclusion of HVDC and island links within the methodology as proposed in order to ensure that it is reflective of the underlying technological characteristics of the transmission system. The specific benefits of the proposed options for including HVDC and island links within the charging methodology are not presented in the Impact Assessment, as the modelled 'Status Quo' already assumes 100% locational treatment of these assets. However, revisions to take account of HVDC and island links are clearly needed in order to ensure that the charging methodology incorporates transmission technology configurations that are present or anticipated within the GB transmission system.

## 5.2 Do the proposals better facilitate the relevant CUSC objectives?

The first part of Ofgem's assessment is conducted against the relevant CUSC objectives:

- **Objective (a) 'facilitating competition':** 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.
- **Objective (b) 'cost reflectivity':** 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).
- **Objective (c) 'taking account of developments':** 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.

The following sections focus on each objective in turn, highlighting Ofgem's own assessment and our own interpretation within the same framework.

### 5.2.1 Facilitating competition

Ofgem breaks its assessment of 'facilitating competition' into five component parts, each of which is considered below.

#### 5.2.1.1 Discrimination

Ofgem considers the current charging methodology to be discriminatory on the basis that it only recognises peak security as a driver of transmission investment and does not recognise that transmission investment also takes place to maintain an efficient level of constraint costs. On the basis that WACM2 does seek to include year round considerations alongside peak security, Ofgem considers that it improves the cost reflectivity of the charging arrangements and, as such, reduces discrimination and improves competition.

While there may be a case for revising the charging methodology to include year round considerations, there appears to be a de facto assumption that any methodology which does so is better than the baseline, regardless of the approach. However, the existence and extent of discrimination within the current arrangements are not robustly evaluated and the relative impact of the proposed revisions upon discrimination is not assessed. Therefore, we do not believe that the impact assessment contains the necessary evidence to support the assertion that the proposal will reduce discrimination.

Furthermore, the use of ALF is an inappropriate proxy in TNUoS for SQSS approach to year-round assessment. This is arguably discriminatory to those parties who are financially affected by this approach.

In addition, we note concerns raised during the modification process that any simplification, averaging or use of generic factors could be considered as discriminatory in the treatment of certain generation plant types. This issue does not appear to be considered in Ofgem's impact assessment presenting a potential weakness in the evaluation.

The impact upon alleged discrimination is unproven and the proposals arguably introduce discrimination through introduction of ALF.

#### 5.2.1.2 Distributional effects

Ofgem's assessment highlights that the proposed revision leads to a redistribution of costs between the south and the north, with this particularly the case for WACM2. Therefore, Ofgem acknowledges the existence of distributional effects. However, Ofgem expresses the view 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'.

However, the analysis in the 'Regional impacts on generators' section of the impact assessment suggests that Diversity 1 options will reduce total generator profits in South England and South Wales by over £400m in the period 2020-30, while they remain relatively unaffected in Scotland in the longer term. This is a significant distributional impact which is not given due consideration by Ofgem in reaching its conclusion that distributional effects are not disproportionately high.

Furthermore, the reduction in generator profits (particularly for those in the south) is justified on the basis that it is offset by lower consumer bills in the period 2020-30. However, consumer bills rise in the short-term and LCP's review of the modelling approach highlighted '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.' This presents doubts regarding the magnitude of longer-term reduction in consumer bills.

P229 proposal for potential adoption of locational Transmission Losses sets a precedent that where there are material distributional effects with marginal overall benefit – change is not justified. In this instance, there is a similar case of cost transfer between generators via TNUoS for marginal consumer benefit.

The distributional effects are significant and are not given appropriate consideration in the assessment.

#### *5.2.1.3 Impact on generator siting*

Ofgem states that, in principle, a more cost reflective charging methodology should encourage better siting decisions for generation, reducing a potential barrier to entry for intermittent generators in the north, effectively by lowering tariffs for such generators. However, extending this line of argument, it is arguable that, relative to today, the converse is also true in that an intermittent generator in the south will face higher tariffs, increasing barriers to entry for this type of participant.

Unlike new plant, current generation clearly cannot re-site in response to the signals provided by the revised transmission charges. However, the revised charges may affect the timing of plant retirals. The impact assessment flags that the proposed changes will have an impact on gas retirement decisions. The modelling suggests a short term reduction in capacity margins under the CMP213 options in the period 2017-2020 by around 1 percentage point. In addition, Ofgem notes that, in addition to the margin tightening from 2017 suggested by the modelling, there is a risk that the changes could cause a marginal generator (particularly a low load factor gas plant in the south) to close earlier. Ofgem notes that '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'. These downside impacts in the short-term are considered to be outweighed by longer-term benefits. However, the basis for this conclusion is unclear.

Furthermore, the lag in the average load factor calculation could distort closure decisions for plants with declining load factors. For example, stations with declining load factor in negative charging zones may be incentivised to stay on the system for longer than would otherwise be the case. Finally, the implications upon the efficiency of future siting decisions are also not explicitly considered in the analysis.

The downside effects linked to potential hastened retirement of gas plants and the impact on efficiency of future siting decisions are overlooked are overlooked.

#### *5.2.1.4 Impact on dispatch*

Focusing on WACM2, Ofgem's view is that using 5 years of historical data avoids introducing distortions to dispatch. This implies a perceived neutral impact upon dispatch. However, while discarding the highest and lowest values from the averaging process reduces the potential for gaming, there may still be perverse incentives at the margin which could distort dispatch. For example, generators may still be incentivised to run at a different load factor than would otherwise be the case in the knowledge that it will influence exposure to future transmission charges.

A historical load factor approach does not entirely remove scope for gaming at the margins.

#### *5.2.1.5 Impact on stability, complexity and predictability of commercial and regulatory arrangements*

Ofgem acknowledges that the proposed methodology will increase the complexity of the charging arrangements and the level of potential volatility relative to the baseline. However, it considers that these factors are outweighed by perceived benefits of improved cost reflectivity. Both factors could be considered as barriers to new entry.

Complexity will increase under the revised arrangements, as could volatility. Stability may also be affected by other developments such as market splitting under the Target Model, which could potentially unwind some of the effects of CMP213 if implemented.

#### *5.2.1.6 Summary*

Ofgem's own assessment of the proposed methodology against the 'competition' highlights negative implications. However, these are often dismissed or over-ruled by the cited benefits of a perceived improvement in cost-reflectivity. In our view, this downplays the significance of these downsides and, as discussed further in the next Section, relies upon a largely unsubstantiated view that cost reflectivity will improve as a result of the proposed revision. A summary overview is provided in Table 10.

**Table 10 – Summary assessment against 'competition' objective**

| Element of assessment | Ofgem view | Pöyry view |
|---|---|---|
| Discrimination | All options (especially WACM 2) reduce discrimination because more cost reflective | The impact upon alleged discrimination is unproven and the proposals arguably introduce discrimination through introduction of ALF |
| Distributional effects | Distribution from north to south under all options, but justified by greater cost-reflectivity and overall benefits for consumers | The distributional effects are significant and are not given appropriate consideration in the assessment |
| Impact on generator siting – entry and exit | All options (esp. WACM 2) better reflect drivers of 'forward-looking' TO decisions | The downside effects linked to potential hastened retirement of gas plants and the impact on efficiency of future siting decisions are overlooked |
| Impact on dispatch | Using 5 years of historical data avoids introducing distortions to dispatch | Historical load factor approach does not entirely remove scope for gaming at the margins |
| Impact on stability, complexity and predictability of commercial and regulatory arrangements | More complex TNUoS arrangements but justified by greater cost-reflectivity and overall benefits for consumers | Complexity will increase under the revised arrangements, as may volatility |

Green: Does better facilitate; Amber: Neutral; Red: Does <u>not</u> better facilitate

### 5.2.2 Cost reflectivity

Ofgem breaks its assessment of 'cost reflectivity' into three component parts, each of which is considered below.

#### 5.2.2.1 Reflecting costs of different users

Ofgem's perspective is that WACM2 improves cost reflectivity on the basis that it seeks to include year round considerations alongside peak security. There appears to be a de facto assumption that any methodology which includes these two drivers is better than the baseline, regardless of the approach and that WACM2 represents not just an improvement but the best improvement. However, this is not demonstrated through the quantitative analysis and the simplifications, averaging and use of generic factors within the proposed methodology may mean that cost reflectivity is not improved, even though the principle of including peak security and year round requirements has merit conceptually.

Proposals are not shown to be more cost-reflective than the status quo.

#### 5.2.2.2 The choice of load factor to reflect 'Year Round' considerations

Ofgem acknowledges that the use of ALF is a proxy for considering the year round considerations that influence transmission investment, noting that the hybrid approach with a more forward looking perspective should improve cost reflectivity in theory, albeit difficult to implement. The simplifications, averaging and use of generic factors within the proposed methodology compromise the perceived cost reflectivity of the ALF solution making it, at best, an approximate proxy for year round investment drivers.

Forward-looking factors would be more cost-reflective (but recognise that this is difficult on plant-specific basis).

#### 5.2.2.3 Bootstraps and island links utilising subsea technology

Ofgem considers that the inclusion within the methodology of an approach for bootstraps and island links represents an improvement in cost reflectivity, on the basis that the current methodology does not include these assets. We see merit in the inclusion of HVDC and island links within the methodology as proposed in order to ensure that it is reflective of the underlying technological characteristics of the transmission system. However, there appears to be a view that the inclusion of these assets via any approach would improve cost reflectivity. We do not believe that this should be the case per se, as including these links using an inappropriate methodology could worsen cost reflectivity. Echoing comments above in relation to the inclusion of a dual approach, it is important that the merits of the specific approach are assessed, rather than just the general concept.

From a process perspective, while CMP213 covers dual approach, HVDC link and island links as a package, the latter two could arguably have been progressed independently of changes to the charging background. Also, the specific benefits of the proposed options for including HVDC and island links within the charging methodology are not presented in the Impact Assessment, as the modelled 'Status Quo' already assumes 100% locational treatment of these assets.

We see merit in the inclusion of HVDC and island links within the methodology as proposed.

#### *5.2.2.4 Summary*

In principle, we are fully supportive of cost-reflectivity in the charging arrangements on the basis that it delivers appropriate signals to users based on the costs that they impose on the system. This objective has clear merit. However, our concern with the Ofgem assessment is that it does not evaluate or demonstrate either quantitatively or qualitatively that WACM2 improves cost reflectivity. Therefore, the case for the proposed methodology improving cost reflectivity is unproven.

But perceived benefits in cost reflectivity are cited as being a countervailing force which outweighs the negative implications of the proposed methodology in terms of discrimination or siting decisions, for example. Ofgem believes that greater cost reflectivity justifies 'negative' impacts on competition. However, WACM2 is not a better representation of TO decision-making process as:

- constraint costs driven by coincidence of MW (not annual MWh); and
- plant specific information requires backward looking data.

The modelling in the Impact Assessment does not demonstrate greater cost-reflectivity because it does not show material and robust benefits to consumers:

- materiality: savings small compared to overall costs, and uncertainty around key factors; and
- robustness: possible over-estimation of benefits; and no testing of sensitivities.

As, in our view, the case for enhanced cost reflectivity has not been made, the justification for WACM2 unravels. A summary overview with reference to the cost reflectivity objective is provided in Table 11.

**Table 11 – Summary assessment against 'cost reflectivity' objective**

| Element of assessment | Ofgem view | Pöyry view |
|---|---|---|
| Reflecting costs of different users | All options improve cost reflectivity, particularly where move to dual background | Proposals are not shown to be more cost-reflective than the status quo |
| Choice of LF | Hybrid is theoretically more appealing but hard to implement | Forward-looking factors would be more cost-reflective (but recognise difficult on plant-specific basis) |
| Bootstraps and island links utilising subsea technology | Options more cost reflective than Status Quo as Status Quo takes no account of HVDC technology for bootstraps and islands | We see merit in the inclusion of HVDC and island links within the methodology as proposed |

Green: Does better facilitate; Amber: Neutral; Red: Does not better facilitate

### *5.2.3 Taking account of developments*

Ofgem considers the changing generation mix plus the introduction of HVDC and island links as developments driving the change to the charging methodology. As highlighted in previous sections, we are supportive of modifications to the charging methodology which appropriately reflect underlying developments in the system. However, we do not believe that any revision which seeks to reflect market or system developments should be assumed to represent an improvement on the current baseline per se. It is possible for a poor methodology to worsen the baseline. The assessment must consider whether a development is being recognised within the charging methodology on an appropriate basis. Table 12 provides a summary relating to the 'developments' objective.

**Table 12 – Summary assessment against 'developments' objective**

| Element of assessment | Ofgem view | Pöyry view |
|---|---|---|
| Changing generation mix | Remedies issue identified in current arrangements | Acknowledge driver for review but unclear that options represent overall improvement |
| Rules for treatment of island links and bootstrap | Options more cost reflective than Status Quo as Status Quo takes no account of HVDC technology for bootstraps and islands | This issue can be addressed independently of the charging background (and not consistent with modelled version of the SQ) |

Green: Does better facilitate; Amber: Neutral; Red: Does not better facilitate

### 5.2.4 Summary

We do not consider that the Ofgem assessment evaluates or demonstrates either quantitatively or qualitatively that WACM2 improves cost reflectivity. The case for the proposed methodology improving cost reflectivity, as asserted by Ofgem, is unproven. However, improvements in cost reflectivity are a lynchpin of Ofgem's overall assessment against the CUSC objectives. Perceived improvements in cost reflectivity are considered to outweigh detrimental impact on competition, such as distributional effects. However, as enhancements in cost reflectivity are not proven, the underpinning of Ofgem's overall assessment across the piece is eroded. For this reason, we do not believe, on balance, that the assessment demonstrates that WACM2 better facilitates the CUSC objectives.

## 5.3 Do the proposals meet Ofgem's statutory objectives?

The second stage of Ofgem's assessment turns to its wider statutory duties, in particular the following:

- reduction of greenhouse gas emissions;
- security of supply;
- furthering competition;
- consumer bill impacts; and
- best regulatory practice.

### 5.3.1 Reduction of greenhouse gas emissions

Ofgem's assessment is that 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 (e.g. the north of Scotland). This is justified on the basis that lower levels of carbon support are needed in order to meet 2020 targets.

The modelling approach applied constraints on the acceptable solution such that it delivers 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). Unsurprisingly, therefore, the modelling highlights little variation between the proposed options and the status quo in terms of carbon emissions. The reduction in low carbon support costs highlighted by Ofgem is driven by differences in the underlying generation mix. These results are sensitive to the strike price modelling approach, which creates uncertainty surrounding the outputs.

No material benefits in terms of greenhouse gas emissions are shown through the assessment and implications for costs of low carbon support are uncertain given the differences in generation mix between the methodology variants.

### *5.3.2 Security of supply*

Ofgem acknowledges that the modelling implies a reduction in capacity margins of around one percentage point between 2017-20 under the proposed options and the possibility for hastening closure for low load factor generators in the south. However, Ofgem considers that the negative implications in the short term are outweighed by longer-term improvements in capacity margin. However, the interaction with the anticipated capacity market is not clear and so longer term security of supply implications are not clear.

The changes will tighten margins in the short-term, with uncertain implications in the long-term.

### *5.3.3 Furthering competition*

As discussed above, Ofgem highlights a number of areas in which the proposed methodology may have a negative effect on competition (e.g. distributional effects), but considers that these are offset by perceived enhancements in cost reflectivity. In our opinion, the case for improved cost reflectivity is not demonstrated within the impact assessment, as outlined previously. Therefore, the potential negative implications for competition cannot be dismissed and need greater weight within the overall assessment.

Negative implications for competition are downplayed and proposals are not shown to be more cost-reflective than the status quo.

### *5.3.4 Consumer bill impacts*

Ofgem's assessment highlights modelling results which suggest, relative to the modelled status quo, higher consumer bills in 2014-24 followed by consumer bill reductions thereafter. However, the future savings in consumer bills are sensitive to factors such as the capacity margin and low carbon support costs, which creates uncertainty regarding their realisation. The direct impact of the proposed revisions to transmission charging arrangements is unclear.

Short-term increases in consumer bills are discounted on the basis of uncertain future reductions. In this context, other regulatory or market developments may affect the ability to realise the longer-term potential benefits. For example, the potential for market splitting under the Target Model could unwind the effects of CMP213, such that the near-term negative effects are experienced while the future potential benefits are not.

### 5.3.5 Best regulatory practice

Ofgem notes that the modelling implies short term detriments in advance of potential longer-term benefits. It considers that the trade-off is proportionate as the distributional effect is justified by eliminating discrimination, long term efficiency and lower bills. Ofgem also notes that enhancing cost reflectivity is consistent with European developments.

However, we have outlined previously the uncertainty regarding the potential longer-term upside and the demonstration of improved cost reflectivity, which is fundamental to Ofgem's overall assessment.

There is uncertainty regarding longer-term benefits and lack of demonstration of improved cost reflectivity.

### 5.3.6 Summary

In our view, Ofgem's assessment of WACM2 against its statutory duties downplays some of the shorter-term negative consequences while placing too much emphasis on possible longer-term upside, in relation to which there is uncertainty. For these reasons, we do not believe that the assessment demonstrates that WACM2 supports the delivery of Ofgem's wider statutory duties.

**Table 13 – Summary assessment against Ofgem's statutory duties**

| Element of assessment | Ofgem view | Pöyry view |
|---|---|---|
| Reduction of greenhouse gas emissions | All options better promote sustainable development primarily because low carbon plant currently being inappropriately charged (barrier to entry) – demonstrated by reduction in low-carbon support | No material benefits in terms of greenhouse gas emissions are shown through the assessment and implications for costs of low carbon support are uncertain given the differences in generation mix between the methodology variants |
| Security of supply | Not materially affected by the CMP213 options | The changes tighten margins in the short-term, with uncertain implications in the long-term |
| Furthering competition | As per CUSC (a) because most cost reflective, and historical load factor not affect dispatch | Negative implications for competition are downplayed and proposals are not shown to be more cost-reflective than the status quo |
| Consumer bill impacts | WACM 2 provides long-term savings in consumer bills that outweigh short-term increases and redistribution | Short-term increases in consumer bills are discounted on the basis of uncertain future reductions |
| Best regulatory practice | Proportionate – distributional effect justified by eliminating discrimination, long term efficiency and lower bills<br>Low risk because European developments support cost reflectivity | Uncertainty regarding longer-term benefits and lack of demonstration of improved cost reflectivity |

Green: Does better facilitate; Amber: Neutral; Red: Does not better facilitate

## 5.4 Implementation date

Ofgem have proposed an implementation date of 1 April 2014 rather than 1 April 2015 as recommended by the CUSC. This is on the basis it will remedy the perceived defects as quickly as possible. This means that the negative short-term impacts highlighted by the modelling are more likely to be realised. For example, this will increase the potential for advanced retirement of marginal plant, which may tighten the capacity margin and worsen the LCPD related capacity crunch, potentially necessitating the paid return of this plant through balancing services routes. This possibility could be lessened if the implementation date was deferred to a later point.

Furthermore, Ofgem notes that there will be no immediate impact in the short run on new investment decisions as a result of the proposed revision due to lead times for building new generation. On this basis, setting an implementation date further into the future would still provide the desired signal for prospective investors, without the negative short-term effects.

It is also important to note that existing parties must give two years' notice if they wish to relinquish their transmission rights. An implementation date of 1 April 2014 does not fit with this timeline and so means that existing generators are unable to respond to the revised signals and are locked in.

Furthermore, (1) the Impact Assessment demonstrates the short term impact is an increase in costs, (2) no new entry capacity can react that quickly and (3) under existing TEC rules no existing generator can respond to new signals without incurring financial penalty. This puts aside the implications of any 'Yes' vote for independence in Scotland.

As such there is no sound rationale for adopting any change to GB TNUoS in April 2014; especially where there is a distributional impact and change in future behaviour is expected or desired.

# 6. SUMMARY AND CONCLUSIONS

## 6.1 Context and role of CMP213

Under Project Transmit Ofgem identified three key perceived defects with GB TNUoS charging:

- it does not appropriately reflect the costs imposed by different types of generators (in particular renewable generators) on the electricity transmission network as the generation mix evolves;
- it does not reflect the development of High Voltage Direct Current (HVDC) links; and
- it does not take into account potential development of Island links.

We support the need to review the charging methodology to seek to incorporate appropriate treatment for new HVDC and Island links and also to consider whether changes in the underlying generation mix necessitate changes to reflect the impact of different generation types on transmission build. But this is not an automatic requirement for change. The merits of any proposed solution, as opposed to the overarching concept solely, must be assessed thoroughly and demonstrate that better meets relevant Ofgem and CUSC objectives.

Given direct guidance from Ofgem, CMP213 has been the means via which National Grid in consultation with the industry has sought to identify the appropriate change to GB TNUoS charging which appropriately address the three perceived defects identified.

## 6.2 Review of quantitative and qualitative CMP213 Impact Assessment

The quantitative Impact Assessment suggests limited overall benefit of any CMP213 option for the end consumer. This is based on longer term benefits post 2024 marginally outweighing short term dis-benefits up to 2024. Furthermore, it shows that all options increase transmission investment and constraint costs over the period to 2030 vs. current GB TNUoS charging methodology. The option including diversity 1 also increases carbon costs (and thus emissions). The projected reduction in generator costs is the driver of overall benefits to consumers – driven by replacement of offshore wind by onshore wind.

However, the quantitative Impact Assessment conducted for CMP213 is subject to a number of flaws – non-assessment of options isolating each defect, lack of analysis of sensitivity of assessment to different assumptions, non-assessment of use of SQSS approach to address Defect 1 (need to reflect year round drivers of investment). Thus, the quantitative Impact Assessment is lacking robustness and indeed challenged by the findings of the study conducted by the University of Bath.

In its overall Impact Assessment, Ofgem acknowledges the quantitative assessment but places particular emphasis on the merits of CMP213 options versus wider charging objectives – in particular cost reflectivity and thus non-discrimination. It is on this basis that Ofgem identifies WACM2 as its preferred option to be implemented. A central argument used to justify the purported greater cost reflectivity of WACM2 is its reflection of the SQSS approach to year round drivers of transmission investment.

However, WACM2 does not reflect the SQSS. Its use of a historic looking and plant specific MWh based approach to determining the impact of generation on year round investment bears no relation to the relevant SQSS approach. The National Grid analysis is relatively high level and limited – and detailed analysis by Bath University has categorically demonstrated that ALF, especially applied in a uniform manner across GB, is not cost reflective of the impact of generators on transmission investment.

National Grid has stated both within record CUSC Working group discussion and at the CMP213 Stakeholder workshop that it believes WACM2 is more cost reflective than the SQSS. This is not proven - as it has not actually used the exact SQSS methodology as a charging method to test this assertion, nor has National Grid back-cast to see if it would accurately relate to historic transmission investment and its drivers.

It is also not the role of the GB TNUoS charging methodology to be more cost reflective than the SQSS. In other words it is the SQSS which determines the cost reflectivity of GB TNUoS and the GB TNUoS methodology is required to reflect actual TO investment practices as prescribed in the SQSS. Specifically transmission charging should reflect the process TOs actually adopt to determine investment requirements (worth several billion in RIIO-T1) not an academic hypothesis of what might be better – especially where such a hypothesis is at best unproven and arguably refuted by the University of Bath study.

## 6.3 Assessment of the merits of adopting CMP213-WACM2

At best, the overall case for WACM2 is unproven, especially that it is more cost reflective and thus less discriminatory. This is especially important given the marginal overall benefits to end consumers predicated on:

- long term benefits outweighing short term dis-benefits; and
- savings from generator changes outweighing increased transmission costs - which in itself is odd as this is a transmission charge.

Moreover it presents a risk that implementation of WACM2 might actually represent a less cost reflective GB TNUoS charging regime than the existing methodology even despite its lack of dual (peak/year round) approach – which would thus be discriminatory to parties. On this basis it would appear unsound to implement WACM2 without a more robust impact assessment which justifies the qualitative assertions and decision made by Ofgem that it is appropriate to do so.

It is also important to consider both potential unintended consequences and previous precedent in relation to proposed transmission charging reform. Any early reaction to WACM2 based GB TNUoS will take the form of plant mothballing and/or closure but no acceleration in new entry is possible. If this outcome were to materialise, it would exacerbate Ofgem's projected capacity squeeze in the period up to the implementation of the GB Capacity Market in 2018/19 without countermanding intervention e.g. using the proposed Supplemental Balancing reserve service to unwind this mothballing/closure. This would clearly result in inefficient costs for consumers.

When locational transmission losses was proposed to be implemented under P229, it was not taken forward specifically due to the impact assessment highlighting that overall benefits were marginal in relative terms but incurred a major distributional impact. This same situation could be argued to apply for CMP213 WACM2 but with arguably less robust supporting analysis. Given the context of the non-robust/unproven case for adopting WACM2, these two factors provide a strong basis for challenging the proposed adoption of CMP213 WACM2.

## 6.4 Merits of proposed timing for revision of GB TNUoS methodology

Finally, Ofgem have proposed an implementation date of April 2014 rather than April 2015 as recommended by the CUSC Panel. This is on the basis it will remedy the perceived defects as quickly as possible. However:

1. the Impact Assessment demonstrates that the short term impact is an increase in costs;
2. no new entry capacity can react that quickly; and
3. under existing TEC rules no existing generator can respond to new signals without incurring financial penalty.

As such there is no sound rationale for adopting any change to GB TNUoS in April 2014; especially where there is a distributional impact and change in future behaviour is expected or desired.

## 6.5 Next steps

In summary, based on our review, Ofgem should:

- reject CMP213 and its alternatives;
- request that the HVDC and island link sections are progressed as separate modifications; and
- evaluate any future proposed modifications to the charging background seeking to introduce sharing based on appropriate analysis which robustly assesses potential revisions with reference to the status quo.

[This page is intentionally blank]

# ANNEX A – DETAILS OF CMP213 DESIGN ELEMENTS, ORIGINAL PROPOSAL, AND ALTERNATIVE OPTIONS

## A.1 Key design elements – treatment in Original Proposal and other options considered

The three tables below present Ofgem's summary the options that have been submitted to Ofgem as part of CMP213 for each of the three areas specified by their direction to National Grid and the industry as a result of Ofgem's Project TransmiT[17].

**Table 14 – Design elements seeking to reflect costs of different users**

| Detail of defect | Proposed solution(s) |
|---|---|
| The current charging methodology only recognises peak security as a driver of transmission investment and charges all plant the same tariff for this.<br><br>This overlooks the second driver of transmission investment as set out in the NETS SQSS – Year Round considerations (efficient management of constraint costs).<br><br>The current TNUoS charging regime does not reflect the two drivers of network investment and how different types of plant contribute toward these. | Aims to better reflect transmission charging with network investment rules so that charging is cost reflective.<br>***NGET's Original:***<br>Aims to reflect this by splitting the TNUoS tariff into two elements; (i) Peak Security, and (ii) Year Round.<br>The Peak Security element would reflect investment for Peak Security reasons. Intermittent generators (e.g. 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.<br><br>The Year Round element would reflect investment to relieve constraint costs efficiently. This would be paid for by all generators. 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.<br><br>***Alternatives featuring Diversity 1:***<br><br>This recognises that areas dominated by low carbon plant tend to drive more transmission investment for 'Year Round' considerations. This is because:<br><br>• the plants are more expensive to constrain off in the Balancing Mechanism[18] – this is due to the interaction with |

17 As sourced from Ofgem's consultation document 'Project TransmiT: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology (Ref: 137/13)'

| Detail of defect | Proposed solution(s) |
|---|---|
| | government's renewable energy support policies; and<br>• low carbon plants often run simultaneously (e.g. when the wind is blowing) and are therefore less able to 'share' transmission network capacity.<br>This approach is the same as the Original until the proportion of low carbon generation exceeds 50% behind a transmission boundary.<br>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. |
| | ***Alternatives featuring Diversity 2:***<br>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.<br>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. |
| | ***Alternatives featuring Diversity 3:***<br>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.<br>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 same tariff). |
| | ***Counter Correlation Factor:***<br>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[19] at a reduced capacity to specifically reflect the counter correlation of differing generation technologies. |

[18] 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.

[19] 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

| **Detail of defect** | **Proposed solution(s)** |
|---|---|
| | |
| ***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:<br>• average 5 year historical ALF; or<br>• 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'[20] 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[21]. These links would be part of the 'local' transmission network from a TNUoS charging perspective (and include onshore radial transmission circuitry).<br><br>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.<br><br>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. |

Source: Ofgem

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.

20 Main Interconnected Transmission System. This is the boundary between the 'local' transmission network (i.e. 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.

21 This has no effect on the user commitment MITS node definition.

**Table 15 – Design elements seeking to reflect the development of HVDC bootstraps**

| Detail of Defect | Proposed solution(s) |
|---|---|
| These are currently not catered for in the charging methodology<br><br>There is a need to:<br><br>a. Reflect DC flows in the current AC only charging model<br><br>b. Recover cable costs<br>Consider whether cost of HVDC converter stations 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 (i.e. from the users of the links rather than on a socialised basis).<br><br>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).<br><br>Industry discussions centred on whether converter stations exhibit the same traits as onshore AC substations[22], the costs of which are not recovered on a locational basis. The options presented to us either:<br><br>• Remove no converter station costs; or<br><br>• Remove some costs (i.e. socialise them[23])<br><br>o 50% based on the cost breakdown of a generic design<br><br>o 60% based on similarity of additional element of design – additional 10% for similarities to Quadrature Boosters (QBs)[24]<br><br>Remove a specific % of costs reflecting the specific cost breakdown of each project that are similar to AC substations. |

Source: Ofgem

22 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 (e.g. 275kv to 132kV). Substations enable power to be transported across long distances and to redirect flows to where the demand is situated.

23 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 (i.e. removing these costs elements further compresses charges, lowers tariffs for generators in the north of Scotland relative to the Original).

24 QBs provide a means of relieving overloads on circuits and re-routing power via more favourable paths.

**Table 16 – Design elements seeking to reflect potential development of island links**

| Detail of Defect | Proposed solution(s) |
|---|---|
| These are currently not catered for in the charging methodology.<br>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<br>c) As with HVDC bootstraps above there are issues around converter stations<br>• Remove no converter station costs, or<br>• Remove some costs[25]<br>o 50% (AC substation equivalent)<br>o 70% based not on extra QBs but on 20% extra for Voltage<br>Source Converters (VSCs) which some argue will benefit the quality of supplies for demand at the remote end of the link<br>Remove a specific % of costs reflecting the specific cost breakdown of each project that are similar to AC substations. |

Source: Ofgem

## A.2 Overview of CMP213 options recommended by CUSC Panel for Ofgem consideration

The CMP213 working group devised different combinations of the key design elements presented in Tables 14-16 above to form 27[26] proposals that were then submitted to the CUSC Panel for their recommendations under the CMP213 assessment process.

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 Table 17 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.

25 See footnote 13.

26 The CMP213 Workgroup originally presented 42 options but these were reduced to 27 that they considered viable.

## Table 17 – Design elements of 8 CMP213 options recommended by CUSC Panel to Ofgem for consideration

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

Source: Ofgem

# ANNEX B – RELEVANT SQSS EXTRACTS[27]

## B.1 Security Background planning criteria for peak conditions on an intact network

'4.4.1 **generating units' outputs** shall be set to those arising from the Security planned transfer condition described in Appendix C;

4.4.2 **power flows** shall be set to those arising from the Security planned transfer condition (using the appropriate method described in Appendix C) prior to any fault, and such power flows modified by an appropriate application of the interconnection allowance (using the methods described in Appendix D) under secured events;

…

4.4.5 sensitivity cases on the conditions described in 4.4.2 and 4.4.4 shall comprise generating units with output equal to their registered capacities such that the required power transfers described in 4.4.2 and 4.4.4 above are approximated by selection of individual units;'

***Appendix C: Modelling of Security Planned Transfer:***

'C.1 For circumstances in which apparent future plant margins exceed 20%, the 'Ranking Order technique' should be applied. Where the apparent future plant margin is 20% or less, the 'Straight Scaling Technique' should be applied.'

'C.2 In derivation of Security planned transfer conditions, the registered capacities of power stations are scaled by availability factors, known as A T, for classes T of power station. For the Security planned transfer condition, these factors are set as follows:

C.2.1 For stations powered by wind, wave, or tides, A T = 0. This zero factor is set for the Security planned transfer condition so that there is confidence that there is sufficient transmission capacity to meet demand securely in the absence of this class of generation.

C.2.2 For imports or exports from / to external systems, A T = 0.'

C.2.3 For all other power stations, A T = 1.0

The ranking order technique maintains the output of directly connected power stations and embedded large power stations considered more likely to operate at times of ACS peak demand at more realistic levels and treats those less likely to operate as non-contributory.

C.4 This is achieved by ranking all directly connected power stations and embedded large power stations in order of likelihood of operation at times of ACS peak demand. Those power stations considered least likely to operate at peak are progressively removed and treated as non-contributory until a plant margin of 20% or just below is achieved.

C.5 In this technique, all directly connected power stations and embedded large power stations on the system at the time of the ACS peak demand are considered

---

27 SQSS (National Electricity Transmission System Security and Quality of Supply Standard – v2.3)

contributory and their output is calculated by applying a scaling factor to their registered capacity proportional to an availability representative of the generating plant type at the time of ACS peak demand such that their aggregate output is equal to the forecast ACS peak demand minus total imports from external systems.

## B.2 Economy Background planning criteria for peak conditions on an intact network

4.4.3 generating units' outputs shall be set to those arising from the Economy planned transfer condition described in Appendix E;

4.4.4 power flows shall be set to those arising from the Economy planned transfer condition (using the appropriate method described in Appendix E) prior to any fault, and such power flows modified by an appropriate application of the boundary allowance (using the methods described in Appendix F) under secured events;

4.4.5 sensitivity cases on the conditions described in 4.4.2 and 4.4.4 shall comprise generating units with output equal to their registered capacities such that the required power transfers described in 4.4.2 and 4.4.4 above are approximated by selection of individual units;'

***Appendix E Modelling of Economy Planned Transfer***

E.1 For the determination of Economy planned transfer conditions plant is categorised in three groups:

E.1.1 non-contributory generation. This plant, such as OCGTs, does not form part of the generation background

E.1.2 directly scaled plant. The output of plant in this category is determined by a fixed scaling factor, described in E.3

E.1.3 variably scaled plant. The output of plant in this category is uniformly scaled by a variable factor that is calculated to ensure that generation and demand balance. This is described in E.5.

E.2 The NETS SO will from time-to-time review, consult on, and publish the categorisation of plant.

E.3 In the Economy planned transfer condition the registered capacities of certain classes of power station are scaled by fixed factors, known as D T, for classes T of power station. These factors are set as follows:

E.3.1 For nuclear stations, and for coal-fired and gas-fired stations fitted with Carbon Capture and Storage, D T = 0.85

E.3.2 For stations powered by wind, wave, or tides, D T = 0.70.

E.3.3 For pumped storage based stations, D T = 0.5

E.3.4 For interconnectors to external systems regarded as importing into GB at the time of peak demand, D T = 1.0

All remaining directly connected power stations and embedded large power stations on the system at the time of the ACS peak demand are considered contributory and their output is calculated by applying a scaling factor to their registered capacity such that their aggregate output is equal to the forecast ACS peak demand minus the total output of directly scaled plant.

## B.3 Investment planning under conditions in the course of a year of operation – including a non-intact network

4.7 The MITS shall meet the criteria set out in paragraphs 4.8 to 4.10 under the following background conditions:

> 4.7.1 Conditions on the national electricity transmission system shall be set to those which ought reasonably to be foreseen to arise in the course of a year of operation. Such conditions shall include forecast demand cycles, typical power station operating regimes and typical planned outage patterns;

…

4.9 The minimum transmission capacity of the MITS shall also be planned such that, for the background conditions described in paragraph 4.7, the operational security criteria set out in Section 5 can be met.

4.10 Where necessary to satisfy the criteria set out in paragraphs 4.8 and 4.9, investment should be made in transmission capacity except where operational measures suffice to meet the criteria in paragraphs 4.8 and 4.9 provided that maintenance access for each transmission circuit can be achieved and provided that such measures are economically justified. The operational measures to be considered include rearrangement of transmission outages and appropriate reselection of generating units from those expected to be available, for example through balancing services. Guidance on economic justification is given in Appendix G.

***Appendix G Guidance on Economic Justification***

G.1 these guidelines may be used to assist in the:

> G.1.1 economic justification of investment in transmission equipment and/or purchase of services such as reactive power in addition to that required to meet the planning criteria of Sections 2, 3, 4, 7 or 8.
>
> G.1.2 economic justification of the rearrangement of typical planned outage patterns and appropriate re-selection of generating units, for example through balancing services, from those expected to be available under the provisions of paragraph 2.13 in Section 2, paragraph 4.10 in Section 4 and 7.19 in Section 7; and G.1.3 evaluation of any expected additional operational costs or investments resulting from a proposed variation in connection design under the provisions of paragraphs 2.15 to 2.18 and/or paragraphs 3.12 to 3.15 and/or paragraphs 7.21 to 7.24.

**G.2 Guidelines:**

G.2.1 additional investment in transmission equipment and/or the purchase of services would normally be justified if the net present value of the additional investment and/or service cost are less than the net present value of the expected operational or unreliability cost that would otherwise arise.

G2.2 the assessment of expected operational costs and the potential reliability implications shall normally require simulation of the expected operation of the national electricity transmission system in accordance with the operational criteria set out in Section 5 and Section 9 of the Standard.

G.2.3 due regard should be given to the expected duration of an appropriate range of prevailing conditions and the relevant secured events under those conditions as defined in section 5 and Section 9.

G.2.4 the operational costs to be considered shall normally include those arising from:

- transmission power losses;
- frequency response;
- reserve;
- reactive power requirements; and
- system constraints,

and may also include costs arising from:

- rearrangement of transmission maintenance times; or
- modified or additional contracts for other services.

G.2.5 all costs should take account of future uncertainties

G.2.6 the evaluation of unreliability costs expected from operation of the national electricity transmission system shall normally take account of the number and type of customers affected by supply interruptions and use appropriate information available to facilitate a reasonable assessment of the economic consequences of such interruptions.

# ANNEX C – CMP213 DRAFT LEGAL TEXT

## C.1 Diversity Option 1 Legal Text

**Revised CUSC [28]**

‘14.4.8 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.’

14.14.9 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security Background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.10 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e. the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components -

- o Wider Peak Security component
- o Wider Year Round Not-shared component
- o Wider Year Round Shared component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components -

- o Local substation, and
- o Local circuit

These components reflect the costs of the local network.

[28] Volume 4 of Final CUSC Modification Report (CMP213 Project TransmiT TNUoS Developments). Draft Legal Text

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.16 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.17 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate. The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

Gi = Generation zone

J = Node

NMkm PS = Peak Security Wider nodal marginal km from transport model

WNMkm PS = Peak Security Weighted nodal marginal km

ZMkm PS = Peak Security Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as:

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

**Accounting for Sharing of Transmission by Generators**

14.15.37 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.38 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.39 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;

BIkm ab = boundary incremental km between generation charging zone A and generation charging zone B

ZIkm = generation charging zone incremental km.

14.15.40 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

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

**Calculation of Boundary Sharing Factors**

14.15.44 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2\times\left(\frac{LC}{LC+C}\right)\right)+2$$

Where:
BSF = boundary sharing factor.

14.15.45 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.46 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.47 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.48 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

### Initial Transport Tariff

14.15.82 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km (ZMkm PS ), Year Round Not-Shared zonal marginal km (ZMkm YRNS ) and Year Round Shared zonal marginal km (ZMkm YRS ) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$

$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$

$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

| | | |
|---|---|---|
| $ZMkm_{GiPS}$ | = | Peak Security Zonal Marginal km for each generation zone |
| $ZMkm_{GiYRNS}$ | = | Year Round Not-Shared Zonal Marginal km for each generation charging zone |
| $ZMkm_{GiYRS}$ | = | Year Round Shared Zonal Marginal km for each generation charging zone |
| EC | = | Expansion Constant |

| | | |
|---|---|---|
| LSF | = | Locational Security Factor |
| $ITT_{GiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each generation zone |
| $ITT_{GiYRNS}$ | = | Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone |
| $ITT_{GiYRS}$ | = | Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone. |

14.15.85 In addition, the initial tariffs for generation are also multiplied by the Peak Security flag when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the Annual Load Factor (see below).

### Peak Security (PS) Flag

14.15.87 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.14.87 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.88 For a given charging year 't' the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

14.15.93 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.97-14.15.100.

14.15.96 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type **categories** are listed below;

| Fuel Type |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

# QUALITY AND DOCUMENT CONTROL

| **Quality control** | | Report's unique identifier: **2013/634** |
|---|---|---|
| Role | Name | Date |
| Author(s): | Simon Bradbury<br>Gary Keane | October 2013 |
| Approved by: | Mike Wilks | October 2013 |
| QC review by: | Beverly King | October 2013 |

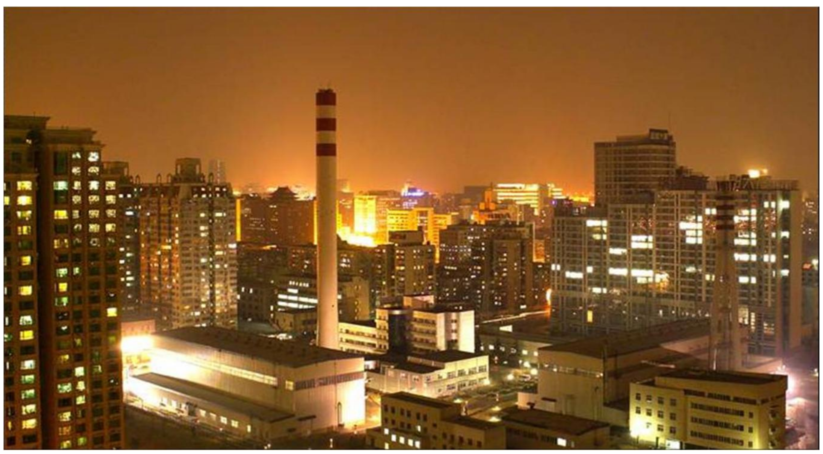
| **Document control** | | | |
|---|---|---|---|
| Version no. | Unique id. | Principal changes | Date |
| v2_0 | 2013/634 | Final version to client | October 2013 |

## Pöyry is a global consulting and engineering firm.

Our in-depth expertise extends across the fields of energy, industry, transportation, water, environment and real estate.

Pöyry plc has c.7000 experts operating in 50 countries and net sales of EUR 775 million (2012). The company's shares are quoted on NASDAQ OMX Helsinki (Pöyry PLC: POY1V).

Pöyry Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and other process industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to Europe's energy markets. Our energy team of 200 specialists, located across 14 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.



**Pöyry Management Consulting**
King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.poyry.co.uk
E-mail: consulting.energy.uk@poyry.com

PÖYRY

Pöyry Management Consulting (UK) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK