Project Transmit: Impact Assessment Consultation (Reference 137/13) SSE Response to Questions

10th October 2013

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

Summary

We consider that the Authority has identified the relevant impacts from the National Grid modelling; of the effects / impacts of CMP213 (including WACM2); and interpreted them appropriately.

It is clear that the modelling presented in the Impact Assessment consultation (and its associated documentation[1]) does provide quantitative evidence of the potential impact of the different options under consideration as part of CMP213.

It is clear to us that this modelling identifies, in great detail, the relevant impacts and in particular the three main areas of:-

i) The impact on power sector costs and the impact on consumer bills;
ii) The deployment of low carbon generation across GB in order to meet 2020 renewable targets; and
iii) The impact on security of supply.

These are the most appropriate impacts; beyond (i) cost reflectivity of charging, (ii) facilitating competition and (iii) reflecting changes in transmission; for the Authority to be mindful of when making its decision on CMP213.

We believe that the modelling supports the transition away from the Status Quo. This transition is based on greater cost reflectivity as is inherent in the SQSS methodology. The modelling illustrates that 'secondary'[2] objectives, namely addressing the Authority's wider statutory duties, such as carbon emissions and renewable targets, customer bills and electricity security, are either not hampered or are actually assisted by this move and should be assisted by this transition. The results of the modelling

[1] In particular:-

- NGET modelling results summary
- CMP 213 Modelling Review of CMP213 Impact Assessment Modelling for Ofgem (Redpoint Energy)
- Quality Assurance of CMP213 Modelling (LCP)
- CMP213 Impact Assessment Modelling Report (NGET)
- Generation Zones within the CMP213 Impact Assessment Modelling (NGET)

[2] The 'primary' objectives being, in this case, the Applicable CUSC (charging) Objectives.

show both Original and Diversity 1 are successful in achieving both the primary and secondary objectives as both are more cost reflective than the Status Quo and both would enable UK renewable and climate change targets to be met with a lower power sector cost.

A move to Improved ICRP in principle delivers the following benefits and the modelling supports the fact that these benefits are likely to be gained by moving to Diversity 1 or the Original:-

- Improves cost reflectively in principle (and has been shown to do so by the modelling);
- Better facilitates competition in principle (and has been shown to do so by the modelling); and
- Better reflects developments in the Transmission business in principle (and has been shown to do so by the modelling).

In coming to this view we have been mindful of the additional reviews undertaken by (Redpoint) Baringa and Lane, Clark & Peacock (LCP). These two reviews are very thorough and helpful to parties as they show that the modelling undertaken by National Grid is credible, comprehensive and reasonable.

Having been involved in the (CUSC) CMP213 Workgroup deliberations we were already comfortable with the process behind National Grid's modelling results whilst being aware of its unavoidable shortcomings.

However, we recognise that, due to the complexity of the factors involved in the modelling and the risk that modelling results may be based more around assumption differences between scenarios rather than robust consequences of the different charging approaches, that the decision over which option to go forward with should not be based on the modelling alone. Given the small differences in results which may be more to do with assumptions, e.g. the plant margin levels and the renewable penetration levels in different scenarios, the modelling should be used to give assurance that the preferred approach will not have significant negative impact rather than being used to determine the appropriate option to implement.

We have considered each of the various aspects of the modelling that are examined in the consultation document and provide our views on these, in turn, below.

Related to the modelling, it might be suggested, by those seeking to delay change that with numerous other proposed changes to the GB power market currently underway that this should necessitate, on the part of the Authority, further modelling or (re)assessment before the Authority comes to a decision on CMP213. We believe there is no justification for this. Examples of some of these ongoing areas of development, which some might suggest warrant further delay to CMP213, include the raft of EMR developments, like the Capacity Mechanism and CfD, or the DECC proposal[3] for a Scottish Islands specific CfD, or the Electricity Balancing SCR, or the

[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/240393/consultation_additional_support_island_renewables.pdf

European Network Codes or, indeed, the very recent announcement from the Leader of the Opposition concerning energy market and regulatory changes. We explore this further, with respect to the DECC proposal for a Scottish Islands CfD, in Appendix 4.

However, such arguments for delay of the CMP213 decision are spurious and a recipe for never making any decision on anything at anytime as there are always ongoing 'initiatives', 'proposals', 'ideas' etc., which could, if implemented, have some 'effect' or 'impact'.

A variation on this call for delay would be to say that even where an initiative is known that we should then wait a conveniently unspecified period of time until the other initiative(s) has been 'implemented' or even 'bedded down' before implementing a transmission charging change such as CMP213.

Given the constantly changing nature of the GB and European electricity markets an approach of waiting until 'initiative X' or 'proposal Y' or 'change Z' has been either 'defined' or 'implemented', so that its impact could be adequately modelled / assessed by the Authority, is entirely unworkable.

Such an approach would raise the possibility of never being able to change anything on the grounds of how other potential changes could impact the results. This is an unworkable way of dealing with change, with nothing being able to be changed due to uncertainty over the interaction with other future initiatives. This would result in market paralysis where the market arrangements cannot change.

After over three years of development by Ofgem and the industry, with 10 separate standalone stakeholder consultations whose response periods aggregated to over 59 weeks together with another two weeks of stakeholder workshops plus in excess of eight weeks of further stakeholder groups' deliberations we believe that now is the time to finally conclude Project Transmit.

The modelling prepared by National Grid, with the oversight of both Baringa and LCP, in our view, is more than adequate for the Authority to opine on Project Transmit.

In addition we would like to thank National Grid for providing additional material[4] to industry which has allowed users to calculate[5], for example, their own business impacts arising from CMP213 WACM2, and which has in turn allowed us to assess the impact of this change for our operations.

<u>(i) Purpose of the modelling (p18)</u>

We concur that the objective of the modelling presented is to provide quantitative evidence of the potential impact of the different CMP213 options being considered. In our view the modelling achieves this objective.

[4] http://www.nationalgrid.com/uk/Electricity/Charges/usefulinfo/

[5] via National Grid's "CMP213 2014/15 indicative TNUoS tariffs: WACM2 (Diversity 1) Generation Charge Calculator"

(ii) The modelling undertaken by NGET (p18)

We note that the modelling approach undertaken by National Grid has not changed from that undertaken during the SCR which had been subject to numerous stakeholder review and comment opportunities, either via the stakeholder working groups or the associated consultations over the past three years.

As such we are sure that all stakeholders have had ample opportunity to raise any fundamental concerns, over the National Grid modelling approach, prior to this consultation.

If a party were, at this very late stage, to seek to raise in their response to this consultation, issues of concern, a question would have to be posed to them as to why their concerns were not raised sooner.

We note that with any modelling of anything, let alone something as fluid and dynamic as the GB electricity market with its numerous parties and variable elements (both within and out with GB), there will always be a balance to be struck between representative modelling and over-complicated modelling. The danger is that in seeking to model 'everything' that we cannot see the wood for the trees and lose sight of the principles which should underpin the decision being made.

The simplified approach to the modelling adopted by National Grid and widely supported by stakeholders during the process is, in our view, appropriate and proportionate. In this regard we took comfort from the involvement of CMP213 Workgroup members from both RWE and GdF Suez in the (CMP213) modelling ‘sub group’. They were heavily involved in developing the National Grid modelling approach and supporting National Grid during the modelling itself.

In our view National Grid's approach to modelling is both a fair representation of the GB electricity market in the short, medium and long term as well as striking a fair balance between over- and under- complexity. This in no small part is due to the considerable industry support provided to National Grid during the development and subsequent 'upgrades' to the model based on the collaborative approach that National Grid has engaged in with stakeholders during the modelling.

In terms of the options modelled, we agree with Ofgem, as noted in paragraph 4.3, that the selection of options modelled by National Grid does provide a representative range of the different permutations that need to be assessed.

We do however wish to outline that, in particular, the consumer bill aspect of the modelling is misrepresentative as it is based upon a feed-through from Transmission charging to system margins to wholesale prices to customer bills which is not very robust. It is equally likely that the implementation of a change to charging would result in a drop in wholesale prices as less plant in the north of GB retires than would be the case under Status Quo.

We believe a simplified model is an effective method for highlighting the increased cost reflectivity of using an Annual Load Factor (ALF) as per the Original and

Diversity 1. We would like to draw your attention to a report by Phil Baker, enclosed as Appendix 2, which demonstrates this.

(iii) Reviews of the modelling (p19)

We welcome the two detailed and comprehensive reviews commissioned by Ofgem into the National Grid modelling.

We concur with the conclusions of the Baringa report that the modelling undertaken by National Grid was reasonable and that it produced results that were consistent with the changes made. Whilst the updates did have an impact on the result, this was to be expected given changing circumstances over the modelling time frame.

We concur with LCP's assessment that whilst there had been some minor issues with implementation that these are not material.

(iv) Interpreting the modelling results (p20)

As with any modelling, there is always a risk that "if only X had been modelled" or "assumption Y changed in some way" that the results would have been 'more' robust. It is the very nature of modelling, especially one looking at the complex GB electricity market and the impact of transmission charges on it in the short, medium and long term that there will always be calls for yet more 'modelling'. As we have noted above, the variables used in the modelling as well as those that might be suggested should be included in the model will, by their very nature, vary.

The simplification of the modelling adopted by National Grid may have, on initial examination, some drawbacks. However, these are far outweighed, on balance, by the overwhelming advantage that arises from this approach.

Overall the interpretation of the modelling results by National Grid and Ofgem are, in our view, appropriate. As noted in paragraph 4.11 of the Impact Assessment it is very important when interpreting the modelling results to take account of the issues arising from the simplification approach used. The two separate reviews, one by Baringa and one by LCP have, in our view, highlighted these issues and we believe that Ofgem has appropriately taken these into account.

We agree with Ofgem that the results of modelling can only provide an approximate guide, rather than a definitive position as to the relative impacts that CMP213 might have. This broad sense as to the magnitude of the change is more than sufficient for us and we believe other affected stakeholders, to gauge in a meaningful way the quantitative effects of the change. It is important to recognise the relative scale of the impacts measured compared to the overall quantum of the factor being measured – for example the wholesale cost change shown for the period 2011 to 2020 represents in the order of 1% of the total wholesale cost over this period. Given the market composition, the numerous variables, together with the changing nature of demand for energy and its method of productions it is distinctly possible that the wholesale cost could vary by greater than 1% even under the Status Quo arrangements.

The plant margin figures that are shown in the Impact Assessment[6][7] as outputs from the modelling are very sensitive to input assumptions. Ofgem have explained (at a meeting in London 6th September 2013) that the timing of new build and retirement would not necessarily match the actual changes to plant margins modelled. The differences in wholesale costs between the proposed methodologies and the Status Quo which arise from differences in plant margins may be considered to be within the margin of error of the modelling methodology.

Baringa confirm the sensitivity of this aspect of the modelling, on page 95 of their review, when they said "*Generally the results [regarding consumer bills] are more variable than power sector costs as small differences in capacity margin can lead to large differentials in consumer bills*."

They then go on to outline, on page 96, that moving from Status Quo to Original or any of the Diversity options has "*little or no impact on security of supply*" and thus it is unlikely that there would be a discernible negative impact on capacity margin and hence wholesale costs in the period up to 2020.

However, we agree with Ofgem that the modelling results "*only provide an approximate guide as to the likely 'real world' impacts of the different proposals with a broad sense of the magnitude*." And that "*the qualitative analysis supporting our decision is also important*."

We endorse the Ofgem position, as noted in paragraph 4.12, that it is highly unlikely that any other modelling would provide more robust findings than the current National Grid modelling without incurring significant delay to the process, with a corresponding delay in achieving the benefits of better cost reflectivity etc., that WACM2 would achieve.

In addition, for the reasons we have outlined above, we are not certain that even if such additional modelling were to take place that some future 'initiative' or 'proposal' or 'change' would not render that modelling, in the eyes of those who question this current modelling, 'obsolete' even before it had been produced.

<u>(v) The modelling results (p21)</u>

Our major concern with the modelling results centres on the assessment of the impact on consumer bills. This is a particularly complex and uncertain aspect of the modelling. Our understanding is that this is recognised as a particularly sensitive area where slight changes in intermediate assumptions and modelling consequences could produce quite different results. We also wish to highlight that in particular the cost increases in the period 2011 to 2020 are small compared to the overall costs £1.7Bn compared to the NPV of the wholesale cost of the whole market which we estimate amounts to in excess of £200Bn over the period 2011 to 2020. This clearly indicates that the impact on consumer bills through increasing wholesale prices arising from the implementation of WACM2 (or the other CMP213 options) should not be considered

[6] page 38
[7] page 38

as a major determining factor regarding the Authority's decision to approve this change.

(vi) Impacts on transmission charges (p22)

The modelling of transmission costs illustrates that the method of charging is expected to have little actual effect on transmission costs irrespective of whichever methodology of charging is used. This suggests that the level of locational signal has a limited impact on actual transmission costs.

(a) Generator tariffs (p23)

We welcome the change in transmission charges that result from the use of the Original and Diversity 1 as we believe that this represents a much clearer link between the costs incurred by the Transmission Operators (TOs) in accommodating different technologies as recognised by the use of a "load factor" in the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS). The compression of tariffs observed from the use of the Original and Diversity 1 methods represent a fairer approach to transmission charging.

(b) Regional impacts on generators (p26)

We believe it is important to recognise the uncertainty inherent in the assessment of the change in generator profits presented in the impact assessment. The presented change in profit mainly arises from the modelled impact on wholesale prices which, in turn, are largely driven by the modelled impact of charging options on system margin. We believe that the link between charging model and wholesale prices is not as robust as is presented here. Capacity margins are affected by many factors with transmission costs being one of the least significant. The introduction, by the UK Government, of a capacity mechanism in 2018 will also have a far more significant impact on the system margin resulting and, hence, the level of wholesale prices than the transmission charging regime. We therefore recommend that the assessed impact on wholesale prices, especially in the 2011-2020 period, is not considered as a significant factor in determining which option to implement.

(c) Regional Demand tariffs (p27)

We believe that the change in demand charges presented are not particularly robust, especially the increases in demand charges in Scotland where the change is indicated to arise "*due to differences in transmission and generation investment*". The impact of the charging options on transmission and generation investment, especially in 2014, cannot be considered large enough to produce the increases in Scottish Demand tariffs shown on page 28. The indicative tariffs[8] for 2014/15 provided by National Grid in September 2013 would tend to support this view, as Demand tariffs in northern GB are increasing due to generation capacity reductions in the north that

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National Grid, CMP213 Indicative tariffs 2014/15, September 2013
http://www.nationalgrid.com/NR/rdonlyres/DCC73573-0341-413A-A008-F5AD00B14694/62589/CMP213201415IndicativeTNUoStariffs.pdf

have largely been driven by the continued implementation of the Status Quo transmission charging model.

(vii) Impacts on overall costs (p29)

The most robust and useful aspect of the overall cost assessment is the demonstration that most of the options produce a reduction in power sector costs over both the pre and post 2020 periods. This is an important modelling result and one which supports a transition away from Status Quo. We welcome the overall result on consumer bills but have some significant reservations. We believe that the impact on wholesale costs, as described above, is overplayed. This applies to both the increases seen pre 2020 and the decreases seen post 2020.

(viii) Power sector costs (p31)

We note that there are a number of factors which affect power sector costs and we give our views against these below.

(a) Overall trend in power sector costs (p32)

The results illustrate a significant and robust conclusion that can be drawn from the modelling that Power Sector costs are lowest for Diversity 1 or the Original. This is in line with the intuitive conclusion that can be reached that the current Status Quo charging methodology is likely to result in offshore wind in southern GB being built rather than cheaper onshore wind in northern GB and that the cost of this is greater than the cost of the transmission investment that would be required to facilitate the transfer of the northern generation to southern users.

(b) Generation costs (p33)

The results illustrate a significant and robust conclusion of the modelling that generation costs are lowest for Diversity 1 or Original in the period up to 2020. However, the generation costs for the Original over the period 2021 to 2030 appear to be overplayed. It is difficult to ascertain from the modelling what lies behind this.

(c) Cumulative new build (p34)

We believe that the difference between the Status Quo and the Original is a reasonable reflection of a plausible out-turn scenario. However, we consider that the difference between the Original and Diversity 1 is overplayed. The renewable capacity difference and hence the cost advantage in 2030 demonstrated by Diversity 1 versus the Original is very uncertain.

(d) Retirement decisions (p35)

We note that Ofgem recognise that "*while the transmission charges themselves may change the overall profitability for all generators, the changes in these tariffs cause limited differences in retirement decisions*."

It is important that this is recognised in terms of the impact on wholesale costs, especially in the 2011 to 2020 period. We believe it is important that Ofgem recognise that this impact is so uncertain especially in the 2016 to 2020 period, where customer bills are shown to rise, that they would be better to outline that the customer bill impact over this period is too uncertain to specify.

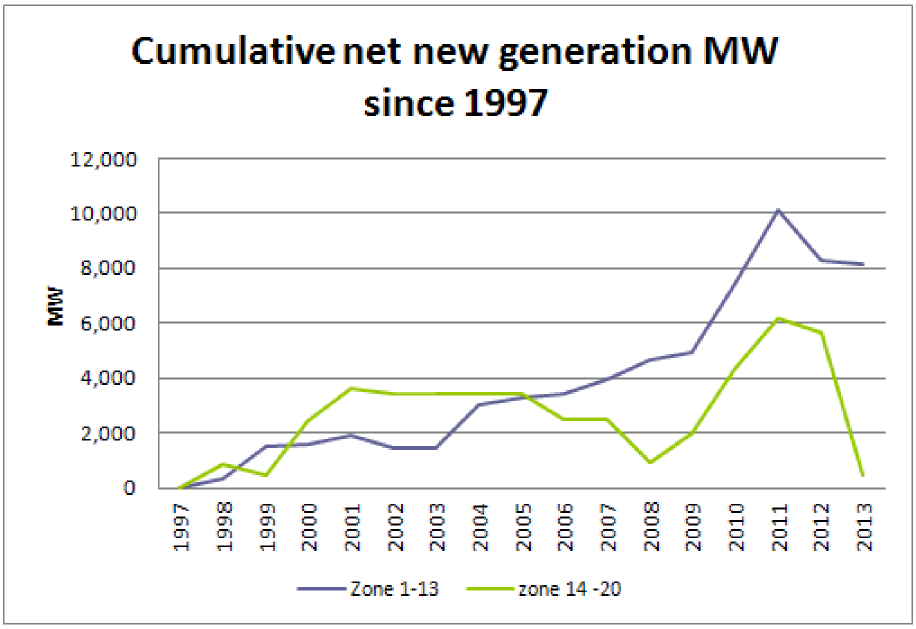
The new methodology results in relatively small increases in cost per kW for southern GB generators compared to the Status Quo. These are well within the range of historic year-to-year changes in transmission charges experienced over the past six years (see graphs below). The historical trends in generation retiral and new build show that generation plant build/closure decisions are subject to many considerations which would likely overshadow this relatively small (£) change to TNUoS charges. This is supported by the following statement from Redpoint[9]:

> *"In particular, factors other than transmission charging that affect siting decisions, such as planning constraints, cooling water access and availability of staff and engineering resources have not been considered."*

The minor effect that TNUoS charges have on plant retirement decisions is illustrated by looking at LCPD plant, with their defined life (20,000 hours). If locational based TNUoS had a significant impact on generation retirement decisions, Ironbridge and Ferrybridge would have front loaded their operating hours under the LCPD hours opt-out derogation and been the first Coal stations to close instead of Didcot and Kingsnorth. In fact the opposite occurred which suggests that TNUoS was not a deciding factor with respect to retirement decisions for generation plant.

It is also clear that the current methodology has failed to provide a sufficient, robust signal to encourage generation plant to locate in the areas indicated by low or negative TNUoS charges. The graph (below) illustrates that since 1997, across GB, the cumulative new generation build in the northern transmission charging zones has exceeded that built in the southern zones. It is thus questionable that this signal should continue to be the basis for transmission charging going forward.

[9] Redpoint (2011), "A Review of' Project TransmiT' Impact of Uniform Generation TNUoS prepared for RWE npower" prepared by Redpoint Energy for SSE - see Appendix 5.



In our view, WACM2 will maintain a locational signal but it will be one that is more cost reflective and will deliver benefits to GB through reduced power sector costs. This is important at a time when the power sector is facing a very significant investment requirement.

(e) Transmission costs (p35)

We concur with the numbers expressed in Table 9 that show transmission costs reducing in all options.

(f) Constraint costs (p36)

We note that the constraint costs illustrated in Figure 10 are broadly consistent with those previously identified in the Code Administrator Consultation. It is clear that constraint costs will be small relative to the transmission system costs post 2016. The modelled differences between the Status Quo and the CMP213 options of between £29-40M can be considered to be insignificant relative to the cumulative investment in the transmission system over the period 2014-2020 of circa £5Bn or the total wholesale cost which we estimate to be in excess of £200Bn. Therefore we consider that, whilst it is appropriate to take account of constraint costs in making a decision in CMP213, little weight should be given to this item in the decision itself in light of the evidence provided.

The modelling of transmission capacity sharing used relatively low bid prices for wind and hence a resultant high constraint cost. The modelling suggests that under all charging options there will be very low constraint costs due to low constraint volumes compared to the Status Quo. We concur with the low constraint cost assessment that came from the modelling but consider that they would be lower in practice as the actual bid prices of capacity behind constraints will on average be higher given the role of non-ROCable hydro and other despatchable renewable generation.

We are also mindful of the substantial growth of embedded generation, especially PV[10 11] and other FiT funded renewable generation, which is predominantly located in southern GB[12]. This will potentially affect the modelling of constraint costs. In our view, GB transmission constraint costs will rise less in the 2016 to 2019 period under the CMP213 alternatives compared to Status Quo as the overall constraint costs under Status Quo are underestimated, due to an overstatement of demand in southern GB.

(ix) Consumer Bills (p37)

We agree with the items identified, in paragraph 4.76 of the Impact Assessment, as being the component elements of consumer bills and concur that the dominant factor is wholesale energy costs. However, we do not agree with the increases in consumer costs over the period 2016 to 2020 presented as we consider these to be based on a modelling result regarding the impact of moving away from Status Quo, its impact on plant retiral levels and thus plant margin then leading to increases in wholesale prices that cannot be considered robust, as we have detailed in our comments under Question 1 (vi) Interpreting the modelling results The difference in plant margin equates to a difference of less than 1% (or about 600 MW, equivalent to one medium sized CCGT or a single unit at a coal station).

We believe that the negative impact on consumer bills over the period 2011 to 2020 arising from the lower modelled capacity margins should not be considered material as they represent less than 1% of the likely wholesale costs, and are anyway subject to significant uncertainty in direction as well as scale.

x) Impacts on security of supply (p37)

We concur with the Authority's view, as set out in paragraph 4.79, that for the purposes of Project Transmit the UK Government's EMR policy intention will develop a capacity market which will ensure security of supply across the modelling horizon.

In terms of the specific capacity margins noted in this section of the consultation document we concur with the broad assessment shown.

We agree with Ofgem that in the period until 2017 transmission charges are likely to be mainly impacted by factors like plant closures, such as those arising due to the

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[10] Financial Times 8th October 2013 “New subsidies have seen solar power surge from 94MW when the coalition took office in 2010 to 2,413MW at the end of June this year.”
http://www.ft.com/cms/s/0/56c09664-2f6b-11e3-8cb2-00144feab7de.html

[11] Greg Barker, Minister of State for Energy & Climate Change, 8th October 2013 “The DECC central forecast estimates that the UK is likely to reach 10GW by 2020. But I believe we can go faster and further. Along with many in the industry, I think that up to 20GW of deployed solar is not only desirable but also potentially achievable within a decade [to 2023].”
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/248717/UK_Solar_PV_Strategy_Part_1_Roadmap_to_a_Brighter_Future_08_10_13.pdf

[12] Ofgem’s September 2013 FiT Update, Figure 1, suggests over 71% of existing FiT installations (by MW) are in an area south of the Mersey / Humber (i.e. Midlands, Wales, East Anglia, London, South East & West and equate, in broad terms, to transmission charging zones 16-27)
https://www.ofgem.gov.uk/ofgem-publications/83475/es803fitupdate-sept2013issue13web1.pdf

LCPD, plant openings, such as those arising in part from EMR, and plant dispatch, such as commodity prices impacting on thermal generation plant merit order positions.

As shown by the modelling results in Figure 12, there then follows a four year period where the capacity margin diverges compared to the Status Quo. Beyond 2020 there are further divergences. However, given the policy framework surrounding EMR we would expect that concerns about the overall GB capacity margin and associated risk to security of supply in the period from 2017 should be addressed via that policy mechanism.

We believe that TNUoS charging is not designed as a policy tool for managing capacity margins. Capacity margins will be managed by security of supply concerns including measures such as the proposed GB Capacity Mechanism, Ofgem's Capacity Adequacy Assessments and potentially Ofgem's Electricity Balancing SCR. We therefore consider that Capacity Margin and consequent wholesale price impacts are inappropriate yardsticks by which transmission charging methodology changes should be compared and selected.

<u>(xi) Impacts on sustainability goals (p39)</u>

We note that the National Grid modelling ensured that the low carbon support mechanisms, such as CfDs, were adjusted to ensure that all charging options modelled deliver, in broad terms, the same level of low carbon output to meet the UK Government's associated sustainability targets. This is entirely consistent with the associated EMR policy framework. Notwithstanding the outcome of Project Transmit, the UK Government's levers of policy, such as Capacity Mechanism / CfDs, will be used to ensure the GB generation portfolio meets the associated sustainability goals for 2020 and 2030 and perhaps beyond.

The variations in renewable / low carbon generation between the CMP213 options, shown in this section (page 39) of the consultation document, are minor and likely to be within the limits of forecast accuracy. We believe that differences in the modelled levels should not be used to differentiate between the CMP213 options.

For example, paragraph 4.89 refers to the possibility under Diversity 2 of an additional 800MW of offshore capacity in the south. However, whilst this may well be one of the effects of the simplified model it could equally be the case, given sub-sea conditions etc., that the transmission connection of an offshore site, say, in the North Sea could land onshore farther north or substantially further south than the National Grid modelling would suggest due to the practicalities of offshore development.

A further illustration of this uncertainty in the modelling is the reference, in paragraph 4.90, to 400MW of additional nuclear capacity in the south being developed under Diversity 3, relative to Diversity 1 or 2. Whilst not a party to the current nuclear developments in GB. We understand, from public domain sources, that the size of the new nuclear units are pre-determined and, given the vast capital cost, limited site locations etc., it is highly unlikely that changes in transmission charges could result in a change in the location of new nuclear of this magnitude.

Therefore, in our view, the modelling shows that the sustainability goals for 2020 and 2030 will be achieved overall and that minor variations in the location of low carbon generation are unlikely to have a significant impact on whether sustainability goals are met. It is therefore reasonable to conclude that sustainability impacts should not be considered as having a material impact on which option should be implemented.

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

Summary

We have some further evidence which may be of relevance to the Authority during its deliberations on this matter.

(i) Oxera

We commissioned Oxera[13] to review the report produced by NERA / Imperial College[14] on 'Modelling the Impact of 'Improved incremental cost-related pricing' that was submitted[15] by RWE npower as part of the CMP213 Workgroup process.

In our view there were some areas of concern with respect to the analysis undertaken and the conclusions drawn in the NERA / Imperial report.

Whilst the Oxera report is mainly a review of the modelling carried out by NERA for RWE npower in 2012 the report contains a useful commentary on the impact of transmission charging on wholesale prices. The Oxera analysis is contained in Appendix 1 and we would like to highlight the following sections from the executive summary. We have also provided relevant extracts of the Oxera review in our response to the various questions posed by this Impact Assessment consultation.

> *"Moreover, the 2012 NERA/Imperial report still shows the instability of the model regarding the locational decision of thermal generation. As the 2012 NERA/Imperial report identifies, the process of completing several iterations that provide the feedback between generation investment decisions, network investment decisions, and the transmission charging model does not lead to a single, stable equilibrium, but one in which location decisions 'flip' between regions in alternate iterations."*
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> *"However, determining the impact of the introduction of Improved ICRP on wholesale electricity prices is not straightforward and the 2012 NERA/Imperial analysis does not appear to capture the locational incentives of the existing arrangements and their implications for wholesale prices.*

[13] This ten page report is contained in Appendix 1 to this response.
[14] NERA and Imperial College London (12th October 2012), 'Project TransmiT: Modelling the impact of 'Improved ICRP', http://www.nera.com/nera-files/pub_transmit_1012_full_report.pdf
[15] 15th January 2013, CMP213 FMR, Volume 3, page 110 http://www.nationalgrid.com/NR/rdonlyres/48D10E02-5CB5-422E-8515-98E0171E1A2A/61006/FinalReportVolume3v10FinalReport.pdf

In particular, the NERA/Imperial modelling uses a profitability-driven approach to determine the siting of new plant, whereas in reality, it is not clear that this is how sites would be developed in practice. There is clear evidence that developments are not progressed along the lowest TNUoS charge path first in the way that NERA/Imperial have assumed. Instead, investors are building plant at a mix of locations, e.g. with new CCGT developments being considered in Scotland. This spread of plant location would imply that the scale of the impact of improved ICRP charges on the long-run marginal costs of new entrants and consequently on power prices could be smaller than that envisaged if plant were developed on a strict order of profitability and that any difference in electricity prices due to the introduction of Improved ICRP, as modelled by NERA/Imperial, may therefore not be as significant as the authors suggest. The history of new investment location over the past decade supports this view rather than that assumed by NERA/Imperial." [the end of this paragraph links to our graph on how generation plant has located 1997-2013: see Question 1, (vii), (d)]

"It would therefore not appear possible to conclude from the NERA/Imperial report that under Improved ICRP, the extent to which an increase in the costs of a price-setting new entrant relative to the existing arrangements would result in longer-term price rises."

(ii) Phil Baker

We commissioned Phil Baker[16] to review a report produced by the University of Bath[17] in January 2013 that was commissioned by RWE npower and Centrica as part of the CMP213 process. Phil Baker is a BSC Panel member and his Elexon[18] biography outlines his extensive experience in the electricity industry.

The Bath report addressed two aspects of CMP213, namely (a) the use of a generator annual load factor as a proxy for the causation of constraint costs and (b) the use of a dual background for devising the locational signal in TNUoS charges.

In addition to reviewing the Bath report we also asked Phil Baker to provide a qualitative assessment of the three CMP213 Diversity options and of the potential for sharing in situations where more than one renewable technology is present.

Baker's report is contained in Appendix 2. It is split into two parts; Part A looking at the matters arising from the Bath report; and Part B examining the diversity options,

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[16] Phil Baker "joined the [BSC] panel in 2010, following a long career in the electricity supply industry and government, starting with Manweb then moving on to the CEGB, National Grid and finally the DTI/BERR. Philip is currently a Research Fellow with UKERC/Exeter University. Philip has a Master's degree In Electrical Power Systems Engineering from the University of Manchester, is a Chartered Electrical Engineer and a Fellow of the Institute of Engineering and Technology."

[17] CMP213 FMR, Volume 3, page 180 onwards. http://www.nationalgrid.com/NR/rdonlyres/48D10E02-5CB5-422E-8515-98E0171E1A2A/61006/FinalReportVolume3v10FinalReport.pdf

[18] http://www.elexon.co.uk/people/phil-baker/

sharing and renewable technologies. _Note_: Part B is confidential and will be sent under separate cover to Ofgem.

Baker's Report Part A is titled "University of Bath report 'Year-round System Congestion Costs – Key Drivers and Key Driving Conditions': an alternate view." This report considers the conclusions reached by the Bath report regarding the suitability both of using an ALF and of using a dual background. Baker concludes that Bath fails to demonstrate that the use of these simplifying assumptions would produce an outcome which was inferior to the Status Quo. In addition, Baker carries out a quantitative analysis of the existing Status Quo methodology and NGET's Original proposal using a simple three node model, then compares these with the implied cost of transmission which would arise from the application of the SQSS. Baker goes on to conclude that charges arising from NGET's Original proposal are *"...likely to be more representative of the actual costs incurred by the TOs than the existing TNUoS methodology [Status Quo]."*[19]

Baker's Report Part B is titled "Further analysis to provide a qualitative assessment of the three CMP213 Diversity options and of the potential for sharing in situations where more than one renewable technology is present." This report carries out a quantitative analysis of the existing Status Quo methodology, as well as NGET's Diversity proposals 1, 2 and 3 using a simple three node model, and then compares these with the implied cost of transmission which would arise from the application of the SQSS. The report goes on to consider the extent to which sharing of transmission capacity is possible in situations where renewable capacity dominates, but where the operational characteristics of the renewable technologies present are quite different such as Scotland which includes both wind and hydro generation. Baker concludes that:

- Diversity 1 would result in charges for renewable generation which could exceed actual costs incurred in areas of high renewable resource where conventional capacity is low and conventional generation connecting in such an area could face transmission charges that are significantly higher than the incurred costs of connection.
- Diversity 2 and 3 exhibit substantial shortcomings and both are less in tune with the objectives of Project Transmit than the either the Original proposal, or Diversity 1.
- Transmission sharing can occur in areas where low-carbon generation dominates such as the situation that would be the present day combination of some 4 GW of wind and 1.5 GW of hydro capacity behind the Cheviot boundary.

<u>(iii) HVDC</u>

Whilst we have no specific new evidence in respect of the request (in paragraph 5.17 of the consultation document) regarding HVDC convertor stations costs. We do though highlight in our detailed response to Question 4 below that new technical

[19] Baker's Report Part A, Appendix 2, section Executive Summary

information in this area is expected to be forthcoming by the end of this year from the world's leading experts in this field.

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?

Summary

We agree with the Authority's assessment of the options in terms of the strategic and sustainability impacts associated with CMP213, and WACM2 in particular. We have examined each of the items that the Authority has considered and provide our thoughts on each of these in turn below.

We have given careful consideration as to whether there are any impacts that the Authority has not identified. **We conclude that there are no additional material impacts that have not already been considered by the Authority or National Grid or the CUSC Workgroup.**

<u>(i) Potential risk of extreme energy prices and volatility (p42)</u>

We concur with Ofgem's assessment, as set out in paragraphs 5.5 and 5.6, that none of the various CMP213 options (including WACM2) represents a material additional risk in terms of extreme energy prices or volatility in GB. Conversely we think that they reduce the uncertainty around the TNUoS charges presented by the Status Quo approach and will therefore encourage investment in generation required to mitigate the risk of extreme energy price and volatility. In addition, as they encourage greater investment in more cost effective renewable generation they will help reduce GB's exposure to international energy price extremes.

<u>(ii) Risks to the UK's legally binding energy targets (p42)</u>

We note that the National Grid modelling is consistent with the UK's legally binding energy targets associated with decarbonisation and greenhouse gas targets throughout the modelling period (i.e. out to 2030).

However, as Ofgem notes (in paragraph 5.9) this is achieved in the modelling via variances in the CfD strike price which, as a result, could lead to alternatives with higher strike prices having a greater risk of not meeting these legally binding targets. In this regard we take comfort that WACM2 requires lower carbon support levels than, say, the Status Quo and, therefore, there is a lower risk (with WACM2) of meeting the UK's legally binding energy targets.

We agree with Ofgem that "*by reducing tariffs to intermittent generators in northern areas where there is high generation potential targets should be more easily met*" (paragraph 5.10). We believe that the benefit of Diversity 1 in this respect is underestimated by the Impact Assessment given that Diversity 1 involves substantially lower levels of offshore wind which is less certain in cost terms than the onshore wind that it is replaced by.

(iii) Consistency with the UK's 2050 GHG target (p43)

We agree with Ofgem's view that steadily moving to a transmission system with more HVDC and advanced convertor technologies is likely. We believe that this should be taken into account and that there are solid grounds for adopting an approach that does not include all HVDC convertor costs being charged locationally. We provide more information on this in our detailed answer to Question 4 below.

(iv) Interactions of the energy system with wider environmental aspects (p43)

We concur with Ofgem's assessment, set out on page 44 of the Impact Assessment, that the impact of changes to transmission charging associated with CMP213 is unlikely to be significant with respect to the wider environmental aspects, such as visual amenity.

Whilst onshore wind may make up a greater proportion of the GB energy mix, much of this is likely to be conveyed either via existing upgraded powerline routes or via the planned Western and Eastern 'bootstraps'. The differential environmental impacts arising from this, including visual amenity, are likely to be minimal.

The modelling showed that the construction of transmission reinforcement was the same under all of the proposed charging methodologies including the Status Quo (as per above).

(v) Overall (p44)

Overall, having considered in detail the information in the consultation document and the associated reports we agree with Ofgem that moving away from the current 'Status Quo' position to one based on WACM2 will lead to more cost reflective charging for use of the GB transmission system. This will in turn reduce the cost of deploying sustainable generation technologies, such as intermittent generation, as well as remove barriers to its development and deployment. This is to be welcomed.

Our assessment of the National Grid modelling leads us to the similar conclusions as Ofgem, namely that the CMP213 Original and alternatives based around Diversity 1 have the potential for the greatest benefits in terms of sustainability and meeting the UK Governments targets in the short, medium and long term.

The sustainability benefits delivered by Diversity 2 are substantially less than those delivered by Diversity 2. Moreover, the drawbacks of Diversity 2; namely understating the level of sharing and discrimination against generators in zones with a mixture of low carbon and non-low carbon generation, which we outline elsewhere in this response; substantially outweigh these sustainability benefits (of Diversity 2).

Our conclusion, with respect to Question 3, is that we agree with Ofgem's assessment (noted in paragraph 5.22). We too expect that the implementation of the more cost-reflective methodology, introduced by WACM2, will mean that not only will it allow the UK to either meet its various sustainability targets, or achieve levels of sustainability greater than those foreseen under the Status Quo position for the same cost, but that it will do so more efficiently than under the Status Quo transmission charging model. Either of these outcomes is to be highly welcomed as it signals lower costs to consumers and / or greater benefits to consumers for the same cost.

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.

Summary

We believe that there maybe a case for socialising some of the costs of HVDC convertor stations due to the wider benefits that this technology can provide, but that this may need to wait until further information is forthcoming.

We appreciate that the information currently presented to the Authority may not, from the Authority's perspective, be persuasive. We note that the CMP213 Workgroup in coming to their conclusions on this matter took account of work undertaken by the international technical body CIGRE[20].

In this regard we are mindful that CIGRE is currently undertaking a substantial investigation via five separate technical working groups into HVDC which is due to conclude at the end of 2013.

Given this our view is that the benefits of socialising some of the costs of HVDC convertor stations should be examined at a later date and, therefore, that WACM2 should be approved by the Authority, with it being noted by the Authority that this area would be worthy of further investigation in the near future as additional information comes to light.

(i) Further Evidence

We have carefully reviewed the Workgroup deliberations and the associated analysis of the breakdown of the component elements of HVDC convertor stations as set out in Section 5 of the Final Modification Report Volume 1[21] and associated annexes in Volume 2[22].

In addition we have also taken into account the recent study commissioned by Ofgem from SKM "Review of Worldwide Experience of Voltage Source Convertor (VSC)

[20] See for example paragraph 5.32, pg 98, Volume 2 of the FMR
http://www.nationalgrid.com/NR/rdonlyres/639E5187-DBB4-4D6A-9AC2-75CDBB18C501/61005/FinalReportVolume2v10.pdf

[21] http://www.nationalgrid.com/NR/rdonlyres/0E5765AE-2BF5-4B5A-833A-7DFE7AC189F0/61004/FinalReportforAuthority10.pdf

[22] http://www.nationalgrid.com/NR/rdonlyres/0E5765AE-2BF5-4B5A-833A-7DFE7AC189F0/61004/FinalReportforAuthority10.pdf

High Voltage Direct Current Technology (HVDC) Installations"[23]. We note that this report was published after the CMP213 Workgroup had completed its work and, therefore, this analysis was not taken into account during the CMP213 Workgroup deliberations.

We think, in light of this evidence, that there is a case to consider socialising those elements of the HVDC convertor station costs that are equivalent to the onshore AC network elements that are, under the current ICRP methodology, charged locationally, on the basis that elements of the HVDC convertor stations deliver similar wider benefits as the onshore AC network elements that are not included in the ICRP locational cost base.

Reducing the impact of HVDC costs on generators will help the development of the HVDC connections as more generators will come forward requesting connection. This will deliver "learning by doing" and cost reduction benefits which will help reduce the cost of further HVDC developments. Socialising some of the cost will also lead to greater fairness as it will recognise that a significant portion of the benefit derived from the HVDC connection is accrued by parties other than the connecting generators. For example, fairness can hardly be said to apply where existing generators whose presence is not leading to the HVDC investment are being penalised by the increase in their costs resulting from the HVDC investments.

Whilst in our view this evidence is persuasive, we appreciate that this view may not be shared by the Authority. However, it may be the case that in light of new evidence provided the Authority can be persuaded to share this view.

We note the request in paragraph 5.17 of the consultation document seeking further evidence in this area. However, we have no new evidence per se over and above that in the Final Modification Report and the SKM study (see above) to provide at this time.

However, it should be noted that this is an area of continuing technical research. For example, we are mindful that CIGRE[24] [25] held a "Colloquium [on] HVDC and Power Electronics to Boost Network Performance"[26] event in Brazil at the beginning of October 2013. Topic 1 at the Colloquium was on 'Technological Developments' and included a section on HVDC Convertor Stations. Unfortunately it has not been possible to source and therefore review the papers from this event as they have yet to be published.

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[23] https://www.ofgem.gov.uk/ofgem-publications/52726/skmreviewofvschvdc.pdf

[24] "Founded in 1921, CIGRE, the Council on Large Electric Systems, is an international non-profit Association for promoting collaboration with experts from all around the world by sharing knowledge and joining forces to improve electric power systems of today and tomorrow. CIGRE counts more than 2 500 experts from all around the world working actively together in structured work programmes coordinated by the CIGRE 16 Studies Committees, overseen by the Technical Committee. Their main objectives are to design and deploy the Power System for the future, optimize existing equipment and power systems, respect the environment and facilitate access to information."

[25] http://www.cigre.org/What-is-CIGRE

[26] http://www.cigre.org/Events/Other-CIGRE-Events/Colloquium-HVDC-and-Power-Electronics-to-Boost-Network-Performance

We are also mindful that CIGRE established five technical working groups in 2011 to investigate, in more detail, a number of HVDC related matters, including:-

> *“Designing HVDC Grids for Optimal Reliability and Availability performance”*[27]
>
> *“Guidelines for the preparation of “connection agreements” or “Grid Codes” for HVDC grids”*[28]
>
> *“Guide for the development of models for HVDC converters in a HVDC grid.”*[29]
>
> *“Devices for load flow control and methodologies for direct voltage control in a meshed HVDC Grid”*[30]
>
> *“Control and Protection of HVDC Grids”*[31]

All five technical working groups are due to report at the end of 2013 and it seems from their respective Terms of Reference that their reports are likely to provide a substantial body of evidence in the area of HVDC technology.

In light of the technical research from CIGRE, due to be published over the next few months, we believe that the decision of the Authority should be to proceed with WACM2, i.e. reject those CMP213 options with an element of socialisation of some of the HVDC convertor station costs, whilst highlighting in its decision letter that this is an area of work that would merit further examination prior to the commissioning of the “bootstraps” and their integration into the GB transmission charging arrangements.

In this regard we note that ‘WesternLink’, the developer of the first GB HVDC transmission link, “expect to complete the project, including the construction of the two convertor stations, in 2016”[32].

Given this it is clear that there is sufficient time, between late 2013 and the first GB HVDC transmission link having to be incorporated into the charging arrangements by 2016, to reflect upon the new technical information which is expected to be published by the end of 2013 and, if necessary, proceed with a future (CUSC) Modification to better reflect the wider benefits that HVDC convertor stations offer.

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[27] http://b4.cigre.org/WG-Area/B4-60-Designing-HVDC-Grids-fro-Optimal-Reliability-and-Availability-Performance
[28] http://b4.cigre.org/WG-Area/B4-56-Guidelines-for-Preparation-of-Connection-Agreements-or-Grid-Codes-for-HVDC-Grids
[29] http://b4.cigre.org/WG-Area/B4-57-Guide-for-the-Development-of-Models-for-HVDC-Converters-in-a-HVDC-Grid
[30] http://b4.cigre.org/WG-Area/B4-58-Devices-for-Load-flow-Control-and-Methodologies-for-Direct-Voltage-Control-in-a-Meshed-HVDC-Grid

[31] http://b4.cigre.org/WG-Area/B4-B5-59-Control-and-Protection-of-HVDC-Grids
[32] http://www.westernhvdclink.co.uk/qanda.aspx

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

Summary

We agree with the Authority's initial assessment of the appropriateness of implementing WACM2 against the Applicable CUSC (charging) Objectives.

(i) Relevant CUSC objectives (p45)

We agree that all of the CMP213 options better meet the Applicable CUSC (charging) Objectives when compared with the baseline (i.e. the Status Quo). Our detailed reasoning, against each Objective, is set out below.

(ii) Competition – Relevant Objective (a) (p46)

(a) Discrimination (p46)

We agree with the assessment of the discriminatory nature of the current methodology. This is supported by Baker[33] who concludes that:

> "*The analysis undertaken for this report [Baker's report Part B], noting again the limitations of the simple model used, suggests that the existing TNUoS methodology is likely to result in charges that are higher than the actual costs of connecting generation in the North. In the case wind or other intermittent generation, the premium is likely to be significant*."[34]

We agree with the Authority's assessment that Diversity 2 and 3 do not effectively address these discriminations. The assumption under Diversity 2 to cap sharing at 50% is spurious, it is not justified by evidence and it is not cost reflective. Diversity 2 would understate sharing and result in discrimination against generators in zones with a mixture of low carbon and non-low carbon generation. Diversity 3 is even more discriminatory than Diversity 2. Diversity 3 uses the same spurious assumption to cap sharing at 50% as Diversity 2, however it also goes further as described by Baker:

> *"Diversity option 3 does not recognise peak security as a driver of network investment and abandons the dual-background approach adopted by the alternatives (and which is effectively mandated by the Authority's direction to NGET)."*[35]

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[33] Baker's Report, Part B: Further analysis to provide a qualitative assessment of the three CMP213 Diversity options and of the potential for sharing in situations where more than one renewable technology is present,- see Appendix 2 .

.[34] Baker Report Part B: op. cit. section 3.1.

[35] Baker's Report Part B op. cit. section 3.6.

> *"Diversity option 3 does not attempt to differentiate between generation technologies in terms of the impact on driving transmission costs and consequently all generating plant behind a particular boundary would face identical charges. This would seem to be at odds with the Direction issued by the Authority, which required that the revised charging methodology should reflect the costs imposed by different types of generators.."*[36]

Baker goes on to conclude:

> "*As with Diversity option 2, Diversity option 3 appears to apply charges that exceed the actual costs of connection for both renewable and conventional generation in all cases... Of all the options developed via CMP213, Diversity option 3 therefore seems least in tune with the aims of Project TransmiT."*[37]

However, we do not agree that Diversity 1 represents a better remedy than the Original on the basis that not all low carbon generation exhibit similar dispatch behaviour.

In particular hydro has very different dispatch costs and should be considered as more akin to 'carbon' generation (according the CMP213 Diversity approach to 'carbon' and 'low carbon' classification) than 'low carbon'. We do not agree that "*all non-thermal plant tend to be more expensive to constrain off than thermal plant*". Hydro plant may signal willingness to be constrained at a higher price than thermal as its non-generation costs may be considerably lower than a thermal plant and its fuel costs may be very similar – i.e. the value of water held for use at another future opportunity. Baker[38] carried out an analysis of wind and hydro generation characteristics and concluded that:

"*If generation is to be categorised, then that categorisation should be based on operating characteristics. In this respect, analysis suggests that hydro generation that has some element of storage capacity will behave more like conventional capacity than wind, and should therefore be categorised as such."*

In light of this assessment regarding hydro generation we are currently considering if it would be beneficial to source further information on bid prices etc. If this were to happen then there could be merit, at a future date, in bringing forward a CUSC Modification to address this matter. However, for the avoidance of doubt, at this stage we are supportive of WACM2.

(b) Distributional Impacts (p47)

Whilst we agree that there is some short term redistribution of costs we consider that the redistribution is fair. If the current methodology worked, this redistribution should happen over time anyway. The fact that even after 21 years of ICRP there remains a large differential between north and south demonstrates that the current methodology represents an ineffective way of apportioning cost as location selection does not respond to the incremental cost signal of Status Quo. This is demonstrated

[36] Baker's Report Part B op. cit. section 3.6.
[37] Baker's Report Part B, op. cit. section 3.5.
[38] Baker's Report Part B op. cit. section 3.6.

in the graph contained in our response to Question 1 (vi) (d) "Retirement decisions" which shows the level of entry and exit by zone over the period 1997-2013.

(c) Impact on siting, and entry and exit decision (p48)

We agree that a change away from the current methodology should reduce barriers to entry to plant in northern GB but also to plant across GB as it should reduce the inherent instability and riskiness of the current charging outcome. We do not think that there will be a net increase in retirement arising from these changes as the negative impact on some generators will be more than matched by the positive impact on other generators and that this is likely to reduce retirals overall.

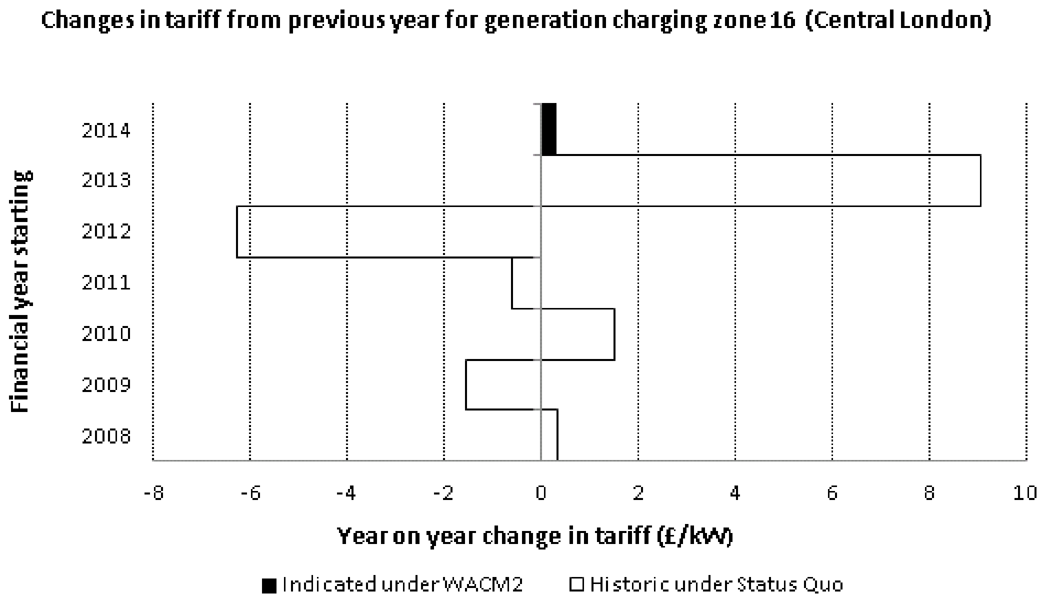
(d) Impact on dispatch (p48)

We agree that the impact on dispatch is likely to be minimal.

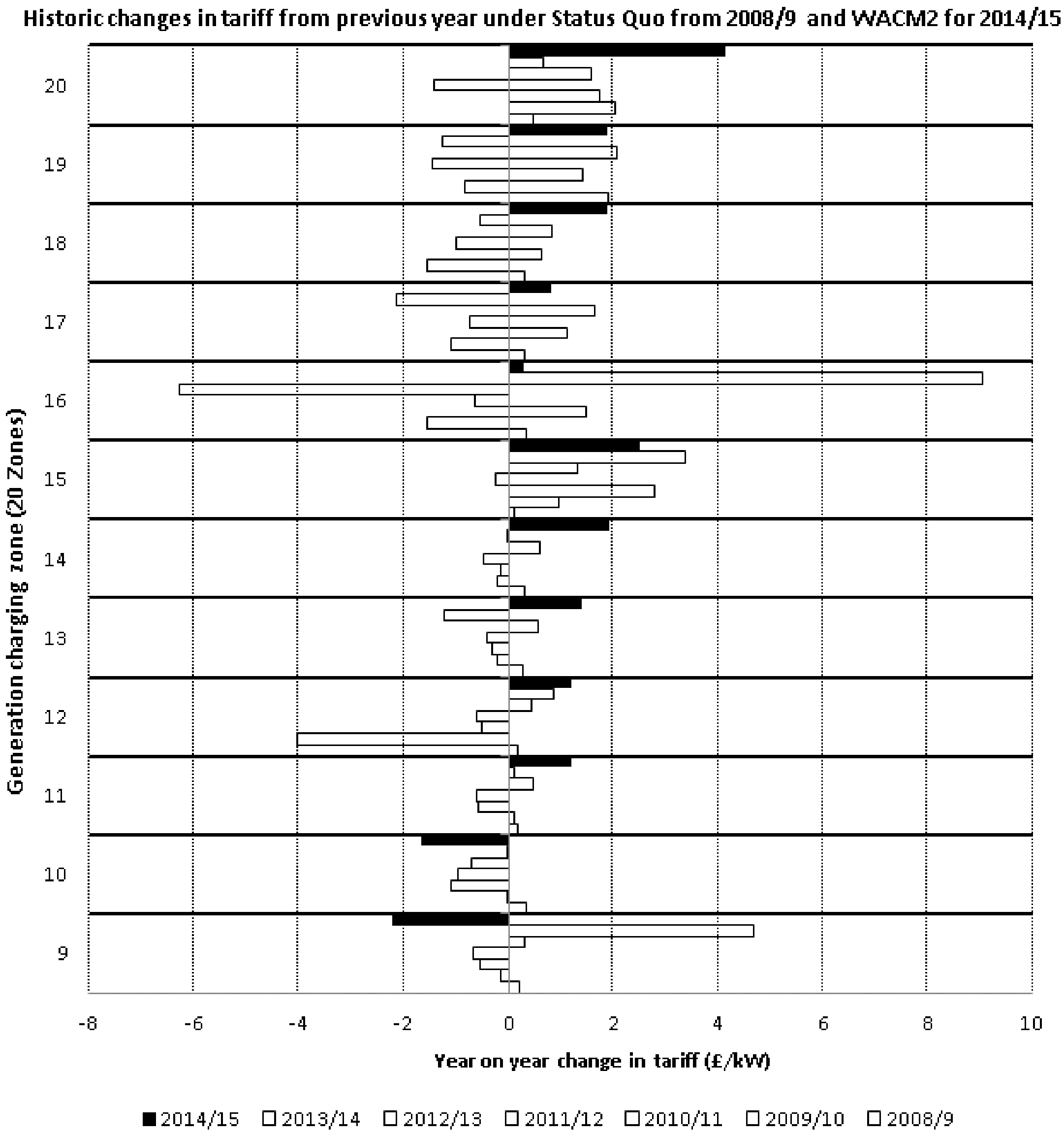
(e) Stability, complexity and predictability (p49)

We believe that transmission charges will become more stable due to the dampening of the influence of "peak" capacity in charging. Charges should ultimately be more predictable long term. Changes may appear more complex, but as they will be less sensitive to zonal entry/exit they will be less complex to predict.

The year on year change in tariffs expected under WACM2 appears similar or lower to those seen in many zones over the past few years under Status Quo. The graph below illustrates this by showing the year to year changes in generator tariffs for transmission charging zone 16, Central London. These, displayed in outline, show that in recent years the annual change to transmission charges for generation under Status Quo have been large, ranging from a reduction of £6 per kW to an increase of £9 per kW. The change expected following the introduction of Diversity 1, shown in black, for a conventional station with a 70% ALF is a relatively insignificant increase of only £0.30 per kW. This uses National Grid's published indicative tariffs, September 2013.



The graph below extends the analysis displayed in the previous graph and shows transmission tariff changes for generation zones 9-20 (of 20 zones). This illustrates the expected changes following the introduction of WACM2 are well within this historic range of the year to year variation in generation tariffs which have occurred in recent years under the Status Quo.



Notes

1. *The indicative tariffs for 2014/15 have been calculated for a thermal generator with a 70% average load factor for the 12 generation zones in E&W (zones 9 to 20) and are real, 2012.*
2. *The graph shows the changes in tariffs from 2008/09 for the 20 zone background consistent with pre-2013/14 tariffs and National Grid's modelling of Improved ICRP. In 2013/14, the 20 zones were increased to 27 zones. To accommodate this change in the number of zones in the simplest way in the graph, the maximum absolute change in tariff (of any split zone) is shown.*

(f) Overall (p50)

Whilst we consider that the Original better facilitates relevant Applicable CUSC (charging) Objective (a) we consider that there is merit in pursuing WACM2 as it too, like the Original, better facilitates relevant Applicable CUSC (charging) Objective (a) compared to the baseline (i.e. Status Quo).

(iii) Cost reflectivity - Relevant Objective (b) (p50)

(a) Reflecting costs of different users (p50)

We agree that moving away from peak-only charging is more cost reflective. We agree that Diversity 1 and 2 are more cost reflective than Diversity 3.

The use of an annual load factor (ALF) applied to the Year Round tariff is more cost reflective than the single Peak Security approach used by the Status Quo. We support the analysis carried out by National Grid which concluded that it is *"...more cost-reflective to charge on a generators actual ALF than charging on generation capacity (TEC) alone"*[39]

This conclusion is also supported by the analysis by Baker who states that:

> *"It seems reasonable to conclude, therefore, that the NGET Original proposal is more likely to satisfy the requirements set out in the Authority's Direction than the existing TNUoS charging arrangements, in that it more closely reflects the costs likely to be incurred by the TOs in developing the system to accommodate different technologies."* [40]

The University of Bath[41] question the use of an ALF as a useful proxy for congestion costs since their modelling concludes that congestion costs will fall once wind begins to be constrained and infers that increasing wind capacity will reduce the need for transmission investment, which clearly does not reflect reality. Baker's report highlights key shortcomings of the Bath analysis, including Bath's assumption that wind generation can be curtailed at zero cost, which is clearly not the case and which is an important driver of Bath's counterintuitive conclusion. The Bath report itself draws attention to this point, going on to recognise that:

> "*...if a premium for bids for wind generation is used then the constraint cost will rise when the curtailment of wind starts.*" [42]

[39] See section 4 of "Final CUSC Modification report – volume 1; CMP213 Project TransmiT TNUoS Developments", June 2013, at http://www.nationalgrid.com/NR/rdonlyres/E4113B9D-FE0A-4312-9DD5-E5DC1044FD89/60493/Volume1v10.pdf

[40] Baker's Report Part A, Executive Summary

[41] Bath op.cit

[42] Year-round System Congestion Costs – Key Drivers and Key Driving Conditions, University of Bath, January 2013. 2.3 p14

Regarding Bath's report, Baker concludes:

> *"...the University of Bath have failed to demonstrate that the use of those simplifying assumptions lead to an outcome that is worse than that delivered by the current arrangements."*[43]

However, we do not agree that Diversity 1 is more cost reflective than the Original. We think that the simultaneous running aspect of "low carbon" plant has been overstated. Baker states:

"...when more than one renewable technology is present behind a particular boundary, each having quite different operational characteristics, then the potential for sharing transmission capacity is considerable even when the capacity of renewable generation in total significantly exceeds that of conventional generation."[44]

And Baker went on to conclude that:

"If generation is to be categorised, then that categorisation should be based on operating characteristics. In this respect, analysis suggests that hydro generation that has some element of storage capacity will behave more like conventional capacity than wind, and should therefore be categorised as such."[45]

However we do believe that Diversity 1 is also more cost reflective than Diversity 2 as the cut-off and digression introduced under Diversity 2 are arbitrary and suggest that there is no sharing when low carbon capacity reaches 100% penetration which is clearly at odds with the position adopted in the SQSS.

(b)Determining the annual load factor for the "Year Round component" (p53)

There are a number of ways this can be done all of which have benefits and drawbacks. On balance we concur with Ofgem's stance on this matter that an average five year historical load factor is the most appropriate.

(c) HVDC links and Island links (p53)

We do not necessarily agree that comparing the treatment of HVDC "bootstraps" to links serving offshore generators is a reasonable justification for not socialising some of the costs of the HVDC bootstraps.

The offshore generation transmission links serve only the enabled generators and these generators are charged appropriately. This is not the case, for example, with either the Western or Eastern 'bootstraps' – the costs of which affect all generators who are on the source end of the link.

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[43] Baker's Report Part A, section 2.4
[44] Baker's Report Part B, op. cit. section 3.5
[45] Baker's Report Part B, op. cit. section 3.6

Furthermore, the offshore generation transmission circuits (unlike either the HVDC 'bootstraps' or the proposed HVDC transmission links, say, to the Scottish Islands) do not connect users (demand) who, after all, pay 73% of transmission charges directly (and 27% indirectly).

We think that it is appropriate to recognise that the treatment of the onshore AC substations is a better comparator for the HVDC "bootstrap" convertor costs. In addition, the reason for the HVDC investments needs to be taken into account.

For example, the Western HVDC "bootstrap" investment has been justified on the grounds of lower societal cost than utilising onshore AC links. According to the two respective TOs, the offshore HVDC cost is similar[46] to the parallel onshore AC 400kV circuits. According to Ofgem and DECC the cost of going offshore is lower[47] than onshore. Given this we would expect the cost, in terms of generator TNUoS tariffs, to also be similar or indeed less, based on these analyses for the offshore cable compared to the onshore route.

Whilst we agree with the statement in the Impact Assessment that *"it is appropriate that costs that are being triggered by users are paid for by those users"* – it is clear that the costs of HVDC are being experienced by many users who did not trigger the investment in HVDC.

(d) Overall (p55)

Overall whilst we recognise that WACM7 could potentially better facilitate Applicable CUSC (charging) Objective (b) as it would better reflected the costs of HVDC, we recognise that the evidence provided to the Authority prior to this consultation was not persuasive enough for the Authority to be 'minded to' approve WACM7 – hence the Authority's WACM2 'minded to' position. We agree with the Authority's 'minded to' position to approve WACM2 as we believe that it does better facilitate the Applicable CUSC (charging) Objective (b).

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[46] Joint SPTL/NGET Planning Statement Western Link (July 2012) paragraph 2.5.2. "Analysis of the existing onshore system showed that the volume of additional capacity required could only be provided through the construction of new transmissions circuits and upgrading of certain existing circuits. Due to the number and scale of these works it was concluded, in this particular case, <u>that the cost of onshore reinforcement would be similar to that of an offshore HVDC</u>." [emphasis added]

[47] Joint DECC / Ofgem ENSG report 'Our Electricity Transmission Network: A Vision For 2020' (February 2012) [page 70] "A number of alternative onshore solutions were considered to increase the boundary capability of the B6, B7 and B7a boundaries. These included:
A number of projects have already been planned to ensure that the maximum capability (4.4GW) of the existing circuits can be realised. Further reinforcement would be required in the form of either two new 400kV transmission circuits: one from the West of Scotland to Lancashire and one from the East of Scotland to North East England or reconductoring existing 400KV double circuit between Harker and Strathaven and additional series compensation in these circuits to provide the necessary boundary capacity. These options were discounted for three main reasons:
(a) They did not represent the most economic solution. The total length of the new circuits would be in excess of 600km; <u>this resulted in a total project cost that was higher than the undersea HVDC option</u>. [emphasis added]

(b) The construction of new onshore overhead line routes would have a greater disruption to land and higher visual impact.

(c) The timescales required to progress a project through the planning and consents process as prescribed in Appendix F would result in higher constraint costs.
For these reasons it was decided not to progress with onshore AC reinforcements."

In due course, as new evidence on HVDC convertor station costs etc., emerges (see our response to Question 4 above for further details) there may well be a case for a new Modification (looking specifically at this issue) to be raised.

(iv) Taking account of Developments - Relevant Objective (c) (p55)

We are mindful of a number of recent developments in the Transmission Owners' transmission businesses that need to be taken into account within the CUSC charging arrangements, including in particular the treatment of HVDC links and links to the islands.

This was also recognised by the Authority in the (Project Transmit) Direction issued to National Grid on 25th May 2012[48]

> *"The UoS charging methodology does not yet consider the manner in which costs relating to high voltage direct current links that parallel the onshore alternating current (AC) network (HVDC links) should be recovered. The Authority considers that in order to facilitate the development of such links it is appropriate for industry to consider how these should be treated within the UoS charging methodology."*

In our view all the options set out in CMP213, including WACM2, do address the recent development with respect to the changes in the Transmission Owners' transmission businesses arising from the introduction of HVDC and island links to connect renewable (and other) generation in an efficient manner.

Furthermore, in light of the introduction of these developments in the transmission businesses arising from the introduction of HVDC and island links it is therefore appropriate that the (CUSC) charging arrangements are amended to reflect these developments.

Therefore WACM2 and the other CMP213 options do better meet the relevant Applicable Objective (c) and therefore we support its implementation.

(v) Overall Assessment of the Relevant CUSC Objectives (p55)

We agree with the Authority's overall assessment of CMP213 against the relevant Applicable CUSC (charging) Objectives. In our view WAMC2 better meets all three of the Applicable CUSC (charging) Objectives. For the avoidance of doubt, in our view, all the CMP213 options related to Diversity 2 and Diversity 3 do not better meet Applicable CUSC (charging) Objectives (a) and (b) because they are neither more cost reflective or facilitative of competition and that these 'disbenefits' outweigh any benefits compared to the Status Quo as regards Diversity 2 and 3 better meeting Applicable CUSC (charging) Objective (c).

In addition we believe that there is a counter risk to the risk highlighted by the Authority, whereby not implementing WACM2 causes closure of marginal generators in the north of GB. Given the relative scale of change in generator TNUoS tariffs; i.e.

[48] https://www.ofgem.gov.uk/ofgem-publications/54063/final-direction-25-may-2012.pdf

greater decrease in generator tariffs in northern GB than increase in southern GB; we think that this counter risk means that a modification away from Status Quo should actually improve Security of Supply as plant in the north of GB is more likely to respond positively by not closing after a change than plant in the south is likely to respond negatively after a change by closing.

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

Summary

We agree with the Authority's assessment of the options against their statutory duties.

We provide our detailed views on each of these below.

(i) Reduction of greenhouse gas emissions (p56)

We agree that all the CMP213 options presented should have a positive impact on the promotion of sustainable development compared to retaining Status Quo. However we do not agree that adopting Diversity 1 results in the significant benefit in terms of low carbon cost compared to the Original. Diversity 1 has some 1.1 GW less renewable energy in 2030 than the Original, made up of 0.9 GW of offshore wind and 0.2 GW of onshore wind, and is 0.9% lower in terms of renewable penetration. Assuming support costs of £80/MWh and £40/MWh and load factors of 35% and 27% for offshore and onshore wind respectively we estimate that this difference would be responsible for about £1.2bn difference in cost over the period 2020 to 2030. This would suggest that if the renewable energy targets were harmonised between the Original and Diversity 1 the low carbon cost would be very similar between the Original and Diversity 1.

(ii) Security of supply (p57)

We believe that there is a counter risk to the risk highlighted, in the Impact Assessment, where not implementing WACM2 causes closure of marginal generators in northern GB. Given the relative scale of change in generator TNUoS tariffs; i.e. greater decrease in generator tariffs in northern GB than increase in southern GB; we think that this counter risk means that a modification away from Status Quo should actually improve Security of Supply as plant in the north of GB is more likely to respond positively by not closing after the modification than plant in the south is likely to respond negatively after the modification by closing.

(iii) Furthering competition (p58)

We agree with the assessment in the Impact Assessment that WACM2 furthers competition in the supply and generation of electricity.

(iv) Consumer bill impacts (p58)

We consider that a reduction in consumer bills arising from a reduction in wholesale electricity prices is as likely as the projected increase in the period up to 2020. As outlined in paragraphs 4.10 to 4.13 the accuracy of the National Grid model is insufficient to allow the extra consumer cost identified for the period to 2020 for options including WACM2 to be taken as a firm conclusion. Baringa[49] outline how this is "*mainly the result of different capacity margins, with tighter margins leading to an uplift in power price.*" Baringa also indicate overall the consumer bill impact "*represents a very small transfer from consumers to producers during the period 2011-2020 (an increase of about 0.5% in the net present value of consumer bills over the period).*" As we have outlined above[50] we do not think that impact on consumer bills presents a robust basis upon which to compare charging options.

We do however support the conclusion regarding long term benefit as this is less impacted by wholesale price differences and thus is less subject to modelling inaccuracy.

(v) Impact on vulnerable and protected customers (p59)

We agree with the Authority's conclusion that "*recognising the issues with the modelling discussed above which might result in the short term costs being overestimated*" and that the CMP213 options will not "*have any material specific impact on vulnerable customers*".

(vi) Impact on health and safety (p59)

We concur with the Authority's assessment, as set out in paragraph 6.85 of the Impact Assessment, that there do not appear to be any identified health and safety implications related to WACM2 (or the other CMP213 options).

(vii) Best regulatory practice (p59)

We agree that the over-riding factor in making a determination regarding the charging methodology should be the elimination of discrimination and the promotion of long-term stable and fair investment signals. We also recognise that the long-term beneficial impact on customers should be considered to outweigh the potential short term detriment, which is likely to be at the upper level of impact and in our view is overstated as we do not think that the modelled short-term increase in wholesale costs are likely to occur.

(viii) Risks and unintended consequences (p60)

We concur with the Authority's assessment, as set out in paragraph 6.90, that there does not appear to be any additional risks or unintended consequences related to WACM2 (or the other CMP213 options) over and above those already set out

[49] Baringa (2013), CMP 213 modelling: Review of CMP213 Impact Assessment Modelling for Ofgem.
[50] See, for example, our comments under Question 1 (ii), (v), (vii) and (ix) and Question 3 (v).

elsewhere in the consultation (and which we comment on elsewhere in this response, as appropriate).

<u>(ix) Overall (p60)</u>

We concur with the Authority's initial view, as set out in paragraph 6.91, that the implementation of WACM2 would be consistent with the Authority's wider duties compared with retaining the 'baseline' Status Quo (for the reasons we have outlined above in our answer to this question).

<u>(x) European Directives (p60)</u>

We note the Authority's assessment, as set out in paragraphs 6.92-6.94, of the European aspects, arising from various Directives, that relate to CMP213.

In our view WACM2 would better meet the key objectives of those Directives in respect of promoting cost-effective, secure and efficient network development and avoiding unjustified discrimination, including against renewable generation, in particular in remote locations such as the Highlands and islands of northern Scotland.

These items have been explored in more detail elsewhere in this response. Overall we agree with the Authority that WACM2 would promote:-

> i) cost-effectiveness by being more cost-reflective by providing for better targeting of costs driven by generators;
>
> ii) efficient network investment compared to the current 'status quo' arrangements; and
>
> iii) non-discrimination, by charging users based on a more appropriate reflection of the impact they have on system reinforcement through the use of a method that considers the transmission system across the year and peak periods.

In addition to the existing European obligations we are also mindful of ongoing changes of policy and associated Directives, Regulations, etc., that are currently under development within the European context. In this regard we concur with the Authority's view that the WACM2 option aligns with European policy trends such as for more cost reflective pricing and represents a relatively low risk evolution of the existing approach.

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.

Summary

Yes, we agree with the Authority's assessment that implementation of WACM2 on 1st April 2014 is appropriate. We do not support any alternative implementation date (and therefore we provide no evidence in this regard).

In coming to this view we have been mindful of a number of arguments in support of a 1st April 2014 implementation date. These are: (i) consistency; (ii) clear sign-posting; (iii) Information Technology (IT) impacts; (iv) windfall gains & losses; (v) volatility; (vi) consequences of delay; and, (vii) consultation period.

(i) Consistency

Implementation of WACM2 on 1st April 2014 would be fully consistent with the Authority Direction issued to National Grid and in particular the comments in the covering letter[51], of 25th May 2012, that:-

> *"Industry will decide the manner and timing of the industry process, but we continue to urge industry to expedite this process and submit a final CUSC modification proposal report, with all the requisite justification and evidence, in a timely manner to ensure benefits are realised as quickly as possible."* [emphasis added]

It is appropriate that when an Authority Direction is issued that urges the expeditious progression of a change proposal that, if, as in this case, the change is deemed worthy of implementation, the implementation itself is also, in the spirit of that Direction, treated in an expeditious manner. In this way the benefits arising from this change can be realised as quickly as possible.

To do otherwise would appear to be perverse as it would imply that there was no need for "*...industry to expedite this [change]..., in a timely manner to ensure benefits are realised as quickly as possible*" as the implementation could be delayed by over a year (if, say 1st April 2015, were chosen). Such a delay would run counter to the initial decision made of expediting the industry change process and would need to be clearly justified. We do not see any robust evidence to support such a turnaround.

(ii) Clear sign-posting

We believe that parties, especially those with generation assets who will be directly affected by the changes to TNUoS, have had sufficient time to factor any potential change into their normal day-to-day risks given that the potential Project Transmit / CMP213 change has been well sign-posted over many years.

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51 http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20SCR%20cover%20letter%2025%20May.pdf

In our view the industry has been aware of the possibility of a substantial change to the basis on which TNUoS tariffs are calculated since at least September 2010. For example, the initial Project Transmit SCR Call for Evidence was published on 22nd September 2010 and concluded, with a direction to National Grid, on 25th May 2012.

We also note that Ofgem has been seeking the expeditious implementation of a long-term solution to TNUoS charging associated with Project Transmit since its inception in September 2010.

Ofgem has made a number of statements referring to a possible implementation date for changes arising Project Transmit as early as 1st April 2012, far less 1st April 2014, for example:

(a) Ofgem 'Project Transmit: approach to electricity transmission charging work' letter 27th May 2011[52]

> *"If appropriate, we aim to implement any change to TNUoS in time for the next charging year, i.e. from April 2012."*

(b) Ofgem Project Transmit Stakeholder event 11th August 2011 'Opening Presentation' (slide 4)[53]

> "*New Charges Target Date Apr 12*"

(c) Ofgem Project Transmit Stakeholder event 11th August 2011 'Closing Presentation' (slide 2)[54]

> 'Implementation'
>
> *•Initiate CUSC process and NGET 2012/13 tariff development –December 2011*
>
> *•Aiming for change, if appropriate, by April 2012–feasibility to be discussed at WG and through consultation process*
>
> *•Ultimately, industry will decide the manner and timing of implementation*

(d) Ofgem 'Project Transmit: electricity transmission charging Significant Code Review update' 9th September 2011[55]

> "*...Implementation of any change, if appropriate, would therefore be after April 2012, the potential implementation date we identified previously*."

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[52] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf

[53] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20opening%20presentation.pdf
[54] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20closing%20presentation.pdf
[55]

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=151&refer=Networks/Trans/PT

These clear public statements have allowed parties to fully prepare for this change, if they so wished.

<u>(iii) IT impacts</u>

National Grid has stated, "*an implementation date of April 2014 is achievable*"[56]. This is a view we and others share. There are no intrinsic changes to existing IT systems or procedures arising from CMP213 which would mean that a transition period between approval by the Authority and implementation of greater than 12 months would be warranted. Indeed the information clearly points to these necessary IT system and procedural changes being able to be undertaken in the period prior to 1st April 2014.

Given this we can see no credible technical reasons to delay implementation of WACM2 beyond 1st April 2014.

<u>(iv) Windfall gains and losses</u>

We concur with the point made in paragraph 6.101 (bullet 1) that any undue delay in implementation of WACM2 would result in the benefits of this change not being realised at the earliest opportunity which would, in turn, lead to 'windfall gains and losses' as those parties for whom the change would not be beneficial would receive a windfall gain (from the delayed implementation) whilst those parties and consumers for whom the change would be beneficial would incur a windfall loss (from the delayed implementation).

Often the arguments surrounding 'windfall gains & losses' are characterised only in terms of those who stand to 'lose' by the change. Often those benefiting are, erroneously in our view, characterised as having received a corresponding 'windfall' from the change being made. This fails to take account of the 'losses' incurred by the delay in implementation of the change to those who (ultimately) benefit, and the 'windfall' that arises from this delayed implementation to those who (ultimately) "lose" from this change.

We commend the Authority for recognising that any delay beyond 1st April 2014 in the implementation of WACM2 would, itself, lead to 'windfall gains & losses', which would be wrong.

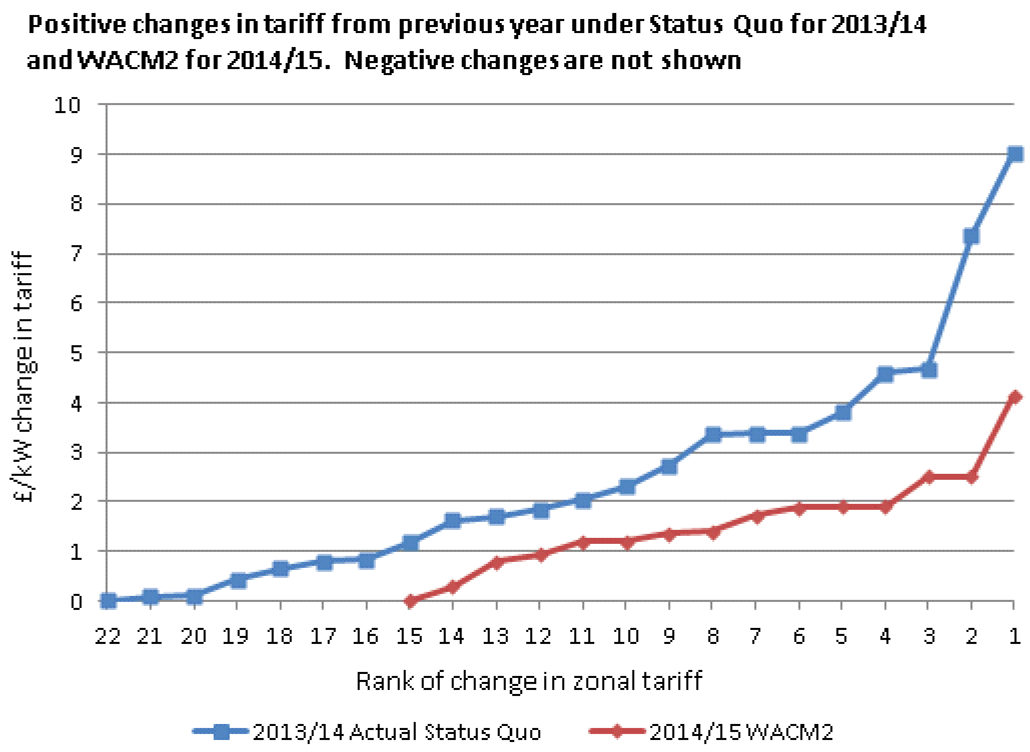
<u>(v) Volatility</u>

One of the arguments often suggested for delaying the introduction of a change, such as WACM2, is that parties are unable to respond. However, the indicated increases in generation transmission charges (according to National Grid's indicative tariffs published in September 2013) under WACM2 are lower than increases seen recently under Status Quo as we have shown in Question 5 (ii) (e) Stability, complexity and predictability. Transmission charges under Status Quo have been volatile and would

[56] Paragraph 1.69, CMP213 FMR http://www.nationalgrid.com/NR/rdonlyres/0E5765AE-2BF5-4B5A-833A-7DFE7AC189F0/61004/FinalReportforAuthority10.pdf

continue to be volatile. This is inherent in a peak only based methodology. We provide further information, including a number of graphs to illustrate the volatility of Status Quo TNUoS tariffs, in our answer to Question 1 - "(viii) Power Sector Costs, (d) Retirement decisions".

There is a clear precedent demonstrated that the changes in TNUoS tariffs in 2013/14 and previous years did not involve any special advance notification, delay, or gradual introduction and since the changes following from WACM2 are smaller than this, there is no case for delaying WACM2 on the basis of the magnitude of tariff increases. The graph below shows the largest year on year zonal increases in the indicative 2014/15 tariffs for a conventional generator with a 70% ALF under WACM2 as published by National Grid (in September 2013) compared with the largest year on year zonal increases in the previous year, using actual 2013/14 tariffs under Status Quo, as published by National Grid. These charges are ranked with the largest increase in zonal tariff shown on the right hand side. This analysis clearly shows the year on year change following the introduction of WACM2 in 2014/15 is substantially smaller with fewer charging zones showing an increase and any increases being much smaller than those experienced in 2013/14.



Given this it seems unreasonable that parties forewarned of the potential change to generator TNUoS, the quantum of which to them, in monetary terms, is of a similar magnitude to the change to their TNUoS tariff which could be expected from the ongoing application of the Status Quo charging methodology, cannot deal with the proposed implementation of WACM2 on 1st April 2014. This is especially true given that normally TNUoS charges would only firm up at the end of January prior to the April of the charging year. In addition we note that the indicative TNUoS tariffs for 2014/15 were presented to parties at the 10th September 2013 TCMF meeting by

National Grid, as well as being discussed at the Ofgem CMP213 workshop on 6th September 2013. This has allowed parties additional time to factor in the effect of WACM2 on their TNUoS charges over and above the time available since indicative tariffs were provided by National Grid during the CMP213 CUSC process.

It is worth noting that absolute increases in TNUoS tariffs are shown because this appropriately demonstrates the financial impact on each generating station. It would be inappropriate and misleading to show any increase of TNUoS tariffs in percentage terms since many southern GB TNUoS tariffs may be close to zero or may flip between positive and negative. This would mean a relatively small (£) increase in a TNUoS tariff could be illustrated as a very large positive or negative percentage change which would not be reflective of the change in costs (£) faced by that generating station.

(vi) Consequences of delay

We believe any delay to implementation if there were to be a delay for instance, to 1st April 2015, would have negative consequences for consumers.

The main consequence would be that the clear benefits arising from WACM2 would be delayed by 12 months. This would mean that generators would not receive the appropriate cost reflective TNUoS charge leading to incorrect and perverse behaviour by those parties which would in turn be counter to and in conflict with the earliest practical realisation of the overall benefits of WACM2 for consumers.

(vii) Consultation Period

Whilst not directly addressed in the Impact Assessment consultation document itself we note that at the 6th September 2013 Ofgem workshop a question was raised from the floor as to whether the duration of the eight week consultation period was appropriate.

Subsequently on 13th September 2013 Ofgem issued an open letter stating that following the receipt of a request for an extension, the consultation period had been extended by two weeks to 10th October 2013.

For the detailed reasons we set out in Appendix 3 and summarise below, we believe there was an overwhelming body of evidence to support the consultation period for the Project Transmit Impact Assessment not being extended beyond the eight week period (i.e. not extended beyond 26th September 2013). Indeed, as we have noted in Appendix 3, there was a strong case to be made for a shorter than eight week consultation period.

SSE's Conclusions on the Authority's "minded to" position

We support the Authority's CMP213 "minded to" position; as set out in their "Project Transmit: Impact Assessment of industry's proposals (CMP213) to change the electricity transmission charging methodology" (Reference 137/13); to approve WACM2 for implantation on 1st April 2014.

We consider that implementing WACM2 on 1st April 2014:

- Improves cost reflectively in principle and has been shown to do so by the modelling.
- Better facilitates competition in principle and has been shown to do so by the modelling.
- Better reflects developments in the Transmission business in principle and has been shown to do so by the modelling.

We believe that implementing WACM2 is in the interests of existing and future consumers and we think it is important that the Authority gives equal weighting to the possibility that there could also be a decrease in consumers' bills in the short term.