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12 April 2017

Dear Andrew,

Consultation response to Ofgem's minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for embedded generators

Thank you for the opportunity to respond to the consultation on your minded-to position of CMP264 and CMP265. This response is provided on behalf of National Grid Electricity Transmission Limited (NGET). NGET is the transmission owner for England and Wales, and the System Operator for the whole of Great Britain. NGET has a number of roles in relation to these code modifications: code administrator for the Connection and Use of System Code (CUSC); the independent chair for the CMP264 and CMP265 workgroup; a member of the CMP264 and CMP265 workgroup; and we are also a member of the CUSC Panel.

Our response to Ofgem's minded-to position has been written mainly as a member of the CMP264 and CMP265 workgroup, and being the party that will have to set TNUoS tariffs if changed by these modifications. This is a non-confidential response, which can be summarised as:

- **We support Ofgem's aim to remove distortions in the market caused by TNUoS Demand Residual (TDR) embedded benefit** on the basis it is in the interest of the consumer. This is the first step towards necessary charging reform to correct a number of distortions caused by embedded benefits in today's electricity market.
- **We support having a reduced value TDR embedded benefit.** Our preference is for a higher value than Ofgem proposes, which is why we supported WACM 7 in the workgroup. This would, as the first step towards developing a level playing field across generators, see an embedded benefit based on the largest negative value of the demand locational signal. Whilst our proposed value of the embedded benefit is not cost-reflective, as an interim solution, we believe the resulting tariff (locational + new embedded benefit) is more cost-reflective than the current value or the Ofgem proposal.
- **We agree with Ofgem's approach of a phased implementation of the new value over three years, and without grandfathering.** This will help embedded generators manage the impact of a reduction in the value of embedded benefits, and in a way a fair and consistent manner.

- **The implementation date of CMP264 and CMP265 needs to be carefully considered.** It should take into account costs from system and process changes, and consider other code modifications that may impact the date of implementation.
- **We see the outcome of CMP264 and CMP265 as an interim solution** ahead of wider necessary charging reform that looks across a number of market distortions and creates a level playing field in charging.
- **We are pleased to see a link to the Targeted Charging Review**, which proposes to look further into arrangements around embedded generation through a Significant Code Review. We will be responding that consultation separately, following Ofgem's recent consultation on future arrangements for the electricity System Operator (SO).

If you have any queries on our response, please contact Paul Wakeley (paul.wakeley@nationalgrid.com, 01926 655582)

Yours sincerely

A handwritten signature in dark ink, reading 'Nicola Medalova' in a cursive script.

Nicola Medalova
Head of Market Change Electricity

NGET's response to Ofgem's consultation on minded to decision and draft Impact Assessment of industry's proposals CMP264 and CMP265.

Question 1: Do you agree with our problem definition and that the Transmission Network Use of System (TNUoS) Demand Residual (TDR) payments to sub-100MW embedded generation ("smaller EG") are distorting dispatch, wholesale price, the capacity market (CM) and that they pose an increased cost to consumers?

We agree with the problem statement as detailed in the consultation. The TNUoS Demand Residual (TDR) embedded benefit has grown significantly in recent years, and is forecast to continue to grow (as evidenced in the latest five year TNUoS forecast, which projects a demand residual of £69.59/kW for 2021/22¹). The value of the payment to embedded generation is not cost reflective of avoided transmission investment as it is currently directly related to the non-cost reflective TNUoS demand residual.

We are pleased to see a broader review of arrangements around embedded generation across transmission and distribution in the Targeted Charging Review. Although the issue of TDR that this proposal aims to address is significant, there are a number of other distortions that need to be addressed soon in the interests of consumers and players across the electricity market:

One example of the non-cost reflectivity in the TDR is in areas of low demand but high embedded generation, where investment is required on the transmission network to manage the flows from the distribution network to the transmission network. In this situation the locational signal may be providing a cost-reflective signal (which may be reduced by the effect of zoning), but as this signal is significantly smaller than the TDR embedded benefit, the effect of the signal is lost. These situations, known as exporting GSPs², are not currently addressed by the charging regime or addressed under CMP264 and CMP265.

In terms of dispatch, as embedded generation must output over the Triad periods to receive the TDR payment, this places the generator as 'must run' in the merit order rather than dispatch in response to the wholesale price which may mean less efficient generation dispatch. As all costs of the GB energy market (network charges, wholesale energy costs etc) are ultimately borne by consumers, any inefficiency will give rise to a higher cost to consumers.

Question 2: Do you agree that rising TDR payments to smaller EG is a problem which needs to be addressed?

Yes, it is a problem that needs addressing as the value of the non-cost reflective TDR embedded benefit is rising and is forecast to continue to do so, driven by increasing revenues for onshore and particularly offshore transmission owners. For example, TDR in 2012 was £22.83/kW, and under the current methodology is forecast to increase to £69.59/kW in 2021/22³. The higher the value of the TDR, the greater the incentive for embedded generation to output at the time of Triad; this further reduces net demand which increases the TDR further increasing the incentive.

¹ Five Year TNUoS Forecast 2017/18 – 2021/22,

<http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589939104>

² In 2015, National Grid undertook a consultation on charging for exporting GSPs:

<http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Transmission-Charges-Open-Letters/>

³ This is the demand residual, and excludes the locational element of the TNUoS charge which varies for each embedded generator depending on where they are located. The 2021/2022 forecast is taken from the February 2017 5 year forecast for TNUoS tariffs.

However, the issue of TDR payments to smaller embedded generation is only one area which gives rise to market distortion. To effectively remove this market distortion and create a level playing field in charging, the value of TDR embedded benefits needs to be considered alongside other charging, access and market arrangements across both transmission and distribution connected parties. Without a broad approach to reviewing all charges experienced by market parties it is likely that we will continue to see subsequent distortions in other parts of the market.

Question 3: Do you agree with our interpretation of the applicable CUSC objectives?

Yes, we agree with Ofgem's interpretation

Question 4: Do you agree with our assessment against the applicable CUSC objectives and statutory duties? Please provide evidence for any differing views.

Yes, we agree with Ofgem's assessment.

Question 5: In our assessment against the objectives, do you believe there are any relevant assessments we have not taken into account?

No.

Question 6: Do you agree with our assessment that, in this instance, grandfathering as set out in the WACMs would be unlikely to best facilitate the CUSC objectives when compared to the other options available to us?

We agree with the use of a phased implementation to avoid a sudden step-change in the value of embedded benefit (from the non-cost reflective) demand residual to the proposed avoided GSP cost (or other figure) as an appropriate way to manage the impact of the change.

We also agree that grandfathering would not best facilitate the CUSC objectives as it would make it significantly more complicated to set and bill tariffs, meaning it is less efficient overall. Given the length of capacity market contracts and associated investment decisions, grandfathered arrangements would likely exist for decades, leading to different rules being applied to similar parties for a long time in to the future. This would likely create another distortion in the market in the longer term.

Question 7: Do you agree with our assessment that the value of the avoided GSP investment cost best facilitates the applicable CUSC objectives?

We agree that the value of embedded benefit related to the avoided GSP investment cost better meets the applicable CUSC objectives compared to the current arrangements. However, our preferred approach, which we believe best meets the applicable CUSC objectives, is for a value of the embedded benefit to be set as the lowest value of the negative locational demand tariff results (WACM 7).

There are two reasons for this preference:

- It establishes an interim value of the embedded benefit that would address the defect ahead of a more detailed review of charging arrangements in a more holistic charging review, (including the enduring regime for all generators).
- The overall signal (locational + new embedded benefit) is more cost-reflective as it retains the correct locational spread between embedded generators in different parts of the country as final tariffs do not need to be capped or collared. Other solutions with a lower value of embedded benefit require the final tariff (locational + new embedded benefit) to be collared at zero to avoid signals for embedded generation to not generate at Triad.

We note that the Avoided GSP Infrastructure Credit (AGIC) as detailed in WACM4 needs to be recalculated under the proposed legal text based on more recent network information. If WACM4 were to be implemented, then we would expect to revise the calculation of the AGIC, and share our calculations with industry, ahead of the implementation of CMP264 / CMP265

Question 8: Do you agree with our assessment of the impacts on security of supply? Please provide evidence for provided views.

We agree with Ofgem's assessment of the impact on security of supply, particularly, due to the future T-1 Capacity Market Auction which could make up for a capacity shortfall. In our role as System Operator we keep security of supply under continuous assessment and we are happy to discuss this with Ofgem on a bilateral basis.

Question 9: Please provide evidence to show if there are other cost savings which small EG drive in comparison to larger (over 100MW) EG on the distribution system.

In terms of flows on the whole system, small embedded generation (<100MW), and larger embedded generation (>100MW) have the same effect per unit of energy. The difference in treatment for charging purposes arises from the different treatment for licensing, and the different methodologies at transmission and distribution charging. These differences create incentives for connection of particular sizes of generation at particular voltage levels (to access or avoid certain types of charges) which may not result in the most efficient siting of generation, dispatch of generation or development of the network. This has an overall effect of increased costs to consumers.

All generators should be treated equally for the purposes of network charging bearing the costs or benefits that they provide to the system. This approach will ensure efficient siting and dispatch of generation, efficient usage and development of the transmission and distribution networks and ultimately lower costs to consumers.

Question 10: Is there other evidence that payment above avoided GSP/generation residual would better facilitate the applicable objectives?

At the CUSC Panel, we voted that WACM 7 best met the applicable CUSC objectives – that is a value of the embedded benefit higher than the avoided GSP / generation residual, based on the value of the largest negative demand locational tariff.

As outlined in our response to Question 7, we believe this higher figure is justified, in the interim, as it avoids creating distortions in the locational signal, addresses the issue of a non-cost reflective

TDR payment and signals to the market that a change in TDR is needed. This still allows a broader review of charging of the whole system to be undertaken to ensure that a change to the TDR alone does not create additional unexpected distortions.

Question 11: Do you believe you have a legitimate expectation or contractual right for the continuation of TDR payments? If so, please provide evidence.

Not applicable for National Grid

Question 12: Do you agree with our assessment of the distributional issues?

The distributional assessment undertaken provides the impact for a range of different plant connected to the distribution networks which may typically be expected to be affected by the change to TDR embedded benefit.

Question 13: Are there any sectors that we may have overlooked?

We do not believe there are any significant sectors that have been overlooked.

Question 14 - Do you agree with our modelling approach?

We support the use of LCP's EnVision model and the Capacity Assessment model. We have used these extensively for analysis in other areas.

Question 15: Do you think that our background assumptions and using FES data is an appropriate approximation for status quo?

We support the use of FES data to model the impact of the Workgroup alternatives. We use FES data in this way to support forward looking analysis and publications in a number of different areas, as well as to underpin an increasing number of strategy projects.

Slow Progression seems a reasonable choice to use for background assumptions, as this is a middle case within the 2016 Future Energy Scenarios from a number of perspectives, including DG build.

We note that 'low' cost assumptions were used for CCGT, OCGT and reciprocating diesel / gas. There is the risk that using low rather than central cost assumptions could overstate the level of future CCGT build (and the associated benefits) and could understate the impact that the removal of TDR would have on distributed generation (build). Whilst the paper notes that backcasting runs of the model for the December 2016 T-4 CM auction gave a clearing price close to the actual result, a number of factors, such as ancillary services, tax incentives, business/regulatory structures, in addition to build cost could affect the final clearing price.

The Capacity Market price projections (p107) resulting from the modelling are different to those projected by a number of independent industry commentators, though we note the range of assumptions and views used to model this across industry.

Question 16: Where WACMs are not modelled directly, do you think our assessment is appropriate (see appendix 8 for detail)?

Yes, the assessment undertaken is appropriate.

Question 17: Of the options available to us, do you agree that WACM4 best facilitates the applicable CUSC objectives?

In line with our response to Question 7 (on the value of the embedded benefit) and Question 6 (grandfathering), and our voting at the Workgroup and CUSC Panel (as detailed in the CMP264/CMP265 Final Modification Report⁴) we believe that WACM7 best facilitates the applicable CUSC objectives, but do note that WACM4 better facilitates the CUSC objectives than the baseline.

Overall we support an approach with no grandfathering and a phased implementation but with a value of embedded benefit higher than the avoided GSP costs (as in WACM 4) and the value based on the largest negative locational demand tariff (as in WACM 7).

Question 18: Do you believe that an implementation date of April 2018 best facilitates the applicable CUSC objectives?

In principle, an implementation date of April 2018 (i.e. the next set of TNUoS tariffs) best facilitates the applicable CUSC objectives as it starts the process of correcting the defect as soon as possible. An implementation date which is not aligned to the tariff setting cycle (i.e. not April and so requiring a mid-year tariff change) would be significantly challenging for National Grid, and cause significant uncertainty for all parties, and would not best facilitate the applicable CUSC Objectives.

An implementation date of April 2018 must however be considered in terms of whether it is *possible* to change the systems and processes that underpin tariff setting and therefore enable tariffs to be reliably forecast and set tariffs with the changes required under CMP264 and CMP265. For this to be possible, National Grid need timely gross metering data to inform our forecasts as we need to set tariffs based on a forecasted change in dispatch behaviour. This means timely access to historic gross metering data, either through the associated BSC modifications (P348/P349) or another source.

An April 2018 implementation date is possible but also challenging, as there is some project quality risk and tariff uncertainty which may lead to a 'mid-year' tariff change in March 2018 (once metered data for winter 2017/18 becomes available). Crucially, an April 2018 implementation could only be achieved with timely decisions on CMP264/265 and on the related BSC modifications P348/P349. If there were delays to CMP 264/265 or the BSC modifications, or changes were not made to the BSC system release in November 2017, it would not be possible to deliver changes to the 2018/2019 tariffs, without significant risk and the need for an additional source of gross metered data.

If an Ofgem decision on CMP 264/265 is made between July and September 2017 we anticipate an April 2018 implementation date to become increasingly challenging. This would result in an increased tariff uncertainty and ultimately an increased risk of a 'mid-year' tariff change.

If an Ofgem decision on CMP264/265 is made after September 2017 we do not judge it feasible, at reasonable cost, risk and to ensure stability of tariffs, to deliver changes arising from CMP264/265 for 2018/19 tariffs.

⁴

<http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589937775>