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Dear Andrew,

Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators

We welcome the opportunity to provide our views on the draft impact assessment and Ofgem's minded-to decision in relation to industry's proposals (CMP264/265).

We support Ofgem's position that the increasing scale of embedded benefits, and TNUoS Demand Residual payments in particular, are distorting the GB electricity market and should be addressed as a matter of priority. To not do so risks locking-in economically inefficient developments and burdening certain customer groups with inequitably high charges.

We agree with Ofgem's approach to assessing the industry's proposals on the basis that charging arrangements should be based on economic principles. In our view, while the Economic Impact Assessment is a very useful tool to validate the economic principles used, it should be the underlying economic principles which determine the direction of change of the electricity transmission charging arrangements.

We support Ofgem's minded-to decision that WACMs 3, 4, 5 are more likely to best facilitate the CUSC objectives, than the Original proposal, and that WACM 4, in particular, is more desirable as it provides the time needed for all participants to adapt to the new



arrangements, compared to WACM 3, and removes unpredictability associated with a generator residual level past 2021, as is the case with WACM 5.

We are satisfied with the modelling approach adopted by Ofgem in assessing the industry's proposals. In our view, a principles-based qualitative assessment, supported by a quantitative assessment of possible consumer/system costs and savings, provides a solid basis for considering the options and making changes to particular aspects of the GB charging regime.

We are looking forward to Ofgem's final decision on electricity transmission charging arrangements for Embedded Generators in the context of the CMP264/265 proposals.

Kind regards,

Polina Kharchenko

Regulation Manager

Consultation questions

Chapter 2: Background

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 (“EG”) are distorting dispatch, wholesale price, the capacity market (CM) and that they pose an increased cost to consumers?

Yes, we agree with Ofgem’s problem definition. As we outlined in our CMP264 and 265 Code Administrator Consultation response¹ and as described in Ofgem’s Targeted Charging Review consultation², the problem can best be understood by considering an approach of principles-based charging.

In our view, when considering the question of the most appropriate design of TNUoS charges (as with all for all types of charging arrangements), it is essential that each element of any charge should be clearly classed as falling into one of two categories (and never both): (1) Economic price signal or (2) Revenue collection. This classification is important because the key principles which determine how individual charging elements should be applied are different for each of these two different categories of charges. The ‘Economic price signal’ category of charges, such as locational charges, should be consistent with the CUSC objectives of cost reflectivity and effective competition. The ‘Revenue Collection’ category of charges, such as residual charges, should follow the ‘optimal tax theory’ where the methodology for revenue collection should be fair and difficult to avoid.

In line with the above, we also agree with the views expressed in the summary section of the CMP264/265 Final Modification Report (FMR)³. Specifically, in sections 12.10 to 12.15 of the Report, workgroup members, supporting an economic case to adjust the residual element of the TNUoS Embedded Benefits, outlined the following views:

- Specific projects/assets should be exposed to price signals which appropriately reflect the impact they have on transmission network costs so that their decisions to

¹ CMP264 ‘Embedded Generation Triad Avoidance Standstill’ (November 2016), CMP265 ‘Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market’ (November 2016)

² Targeted Charging Review: a Consultation: <https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-consultation>

³ Volume 1a Final Modification Report_v1_0: <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/>

invest, dispatch, close or compete for contracts are driven by efficient and non-discriminatory economic considerations.

- Enduring tariffs for EG should be closer in value to locational tariffs of T-connected generators in similar geographical locations, given that these locational tariffs are reflective of the marginal cost that transmission network users, including EG, cause.
- The presence of the TDR benefit causes customers to pay an additional premium, in a form of TDR payments to smaller EG, above the cost required to fund available TNUoS. This causes a feedback loop whereby the escalating value of the TDR benefit enables embedded generators to increasingly crowd out other forms of generation, which causes the value of the TDR cost to customers to escalate further.
- The current embedded benefit regime does not provide a strong locational signal because the magnitude of the TDR crowds out locational price signals. This will tend to cause the transmission system to be larger and more expensive than would otherwise be required, which will tend to cause progressively higher costs to customers.
- Grandfathering preferential TNUoS rates for some EG would be contrary to CUSC objectives of cost reflectivity and effective competition.
- In addition, excessive TDR payments result in market distortions, including out of economic merit investment decisions, despatch decisions, allocation of capacity contracts, awarding of ancillary services contracts, and distorted innovation focused on maximising revenues from embedded benefits instead of genuine economic value. In addition, the scale of these distortions can be expected to result in further unforeseen detrimental impacts on the energy system over the long term. All of these distortions will tend to result in worse economic efficiency of the energy system at a higher cost to customers for a likely lower quality of services.

We also agree with Ofgem's assessment of key distortions which TDR payments are resulting in:

- **Distorting dispatch** – In line with Ofgem's comments in Appendix 5, 'Efficient Market Operation', of the consultation document, we agree that the current ability of EG to earn revenue associated with exempting suppliers from TDR charges results in non-cost effective, "out of merit" generation. This leads to an increase in overall cost to the system as the increased short run costs are not matched by any reduction in the network cost recovered through Triad.

- **Distorting wholesale price** – We also agree that by running out of merit, the wholesale market price is distorted and artificially dampened at peak times. This distortion reduces the economic efficiency of wholesale power market price signals which would otherwise provide an efficient price signal for generators to generate, or customers to reduce their demand. These inefficient price signals will distort the economic decisions made by market participants, which will further increase total system cost and result in higher costs to customers over the long term. The continued existence of this distortion is likely to increase risk premia for generation investment in the long term.
- **Distorting investment via Capacity Market** – We agree that the size of the TDR payment distortion results in smaller EG obtaining a competitive advantage when bidding into the Capacity Market. TDR payments enable smaller EG to reduce their Capacity Market bid prices and, therefore, obtain capacity contracts out of economic merit. This ultimately results in a higher total system cost and higher cost to customers over the long-term. It is also likely to lead to higher environmental costs in the long term arising from the lower efficiency and emission reduction levels achieved by the smaller EG.
- **Increased cost to consumers** – We agree that the distortions described above will tend to cause higher cost to customers over the long-term. If left unchecked, the cost to customers of these distortions would continue to increase indefinitely due to a progressively increasing capacity and progressively increasing dispatch out of economic merit. This effect would be exacerbated by the “feedback effect” that arises from the increasing Triad value which follows from increases in the capacity of smaller EG reducing the net demand Triad charging base which in turn further increases the incentive for further investment in EG. A further “feedback effect” is that the dispatch signal for existing small EG also grows as the Triad value increases, leading to higher dispatch levels. These “feedback effects” could cause the cost to customers to progressively increase indefinitely. In addition the increasing value of the TDR would incentivise greater behind the meter TDR avoidance behaviour from sophisticated customers. All of these effects would compound to result in the end-customer group facing the greatest increase in the costs caused by this defect.

Separately, we would like to draw attention to the serious flaws that undermine the report⁴ produced by NERA Economic Consulting (NERA), commissioned by the Association for Decentralised Energy (ADE), in response to 264/265. We wish to highlight that a number of fundamental errors are central to mistaken conclusion presented in the NERA report:

- NERA claim that the level of the locational element of TNUoS charges do not send cost-reflective signals to network users but are intended to signal only the relative costs of transmission in different locations (Page 22 of the report). This argument is incorrect. TNUoS locational charges do reflect level of incremental cost, i.e. the cost to the network if a user incrementally increased their use of the network (by adding 1 MW) and are not simply relative to each other.
- NERA also claim that the level of the locational charge is affected by the G:D split (page 39 of the report). Again, this argument is wrong because the value of the locational elements of tariffs is independent of the G:D split. By contrast, it is only the Residual TNUoS which is affected by G:D split.
- NERA also claim that the level of the locational charge is affected by choice of a reference node within the load flow model (Page 39 of the report). This is factually wrong. As NERA admit themselves, since the new Transport model has been introduced following the CMP213 process, there is no single reference node, but instead all demand is pro-rata adjusted. This fact invalidates NERA's assertions in this regard. NERA attempted to get around this flaw in their logic by selectively putting 100% of demand at a single node in order to artificially force the model to use a single reference node; however, this approach was neither representative nor helpful regarding the key question of the cost reflectivity of the TDR embedded benefit.
- NERA also claim that the locational charge does not take account of off-peak conditions (page 39 of the report). This is also incorrect because the Year Round background and associated Year Round tariff elements are designed to reflect the Economy Criteria of the SQSS and these do reflect conditions at all times, including off-peak.
- NERA also claim it is evidence of a "problem" that the locational tariffs currently collect a roughly net zero revenue (page 39 of the report). To the contrary, it this is

⁴ Review of Ofgem's Open Letter on Charging Arrangements for Embedded Generation, 23 September 2016, http://www.nera.com/content/dam/nera/publications/2016/160923_NERA-Imperial_Report_to_ADE_on_Embedded_Benefits.pdf

not evidence of a problem, but a reasonable and unsurprising result given the range of locational tariffs where some are positive, some are negative and some are close to zero. Their use of Imperial's Dynamic Transmission Investment Model linked to their assessment of Long Run Marginal Cost resulted in a different net collection, however, their logic is flawed, since the magnitude of net collection is irrelevant for the question of how cost reflective their modelled tariffs may or may not be.

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

Yes. As described above, the “feedback effect” means that if the rising TDR is not addressed urgently, then it is a problem which is only going to become progressively worse over time. The recent rapid growth in smaller EG (much of which, we believe, is being built out of underlying economic merit) has been incentivised in a large part by the recent rapid increases in the TDR (from c.£27/kW to £45/kW with a rise to c.£70/kW forecast in 2021/22). This demonstrates that that the “feedback effect” is already well underway. This is also confirmed by the National Grid analysis (Figure 8 of CMP264/265 workgroup consultation⁵), which suggests that the value of TNUoS Demand Residual embedded benefit, which end customers, who are not able to avoid the charge, are paying for, will be increasing from £343m in 2016/17 to £650m in 2020/21 (real 2016/17 prices). In addition, further analysis by National Grid indicates that if the current (CUSC baseline) situation was permitted to continue, this cost to end customers is forecasted to reach £1Bn in 2030 under the Baseline scenario and £2Bn in 2032 under the Consumer Power scenario from their FES analysis. This growth in cost would mean the value of the Demand Residual avoidance benefit paid by customers to EG would amount to circa 70% of the entire current (2016/17⁶) cost of the total GB transmission network. It is important to note that in addition to this, these same customers would also still have to pay for the bulk of the total ongoing cost of the transmission network (capital and operating cost).

The cost of failing to address the TDR goes beyond the fixed and marginal cost of generation. The value of TDR avoidance also crowds out other economic price signals, so will cause progressively worsening distortions in the outcome of other markets, including:

- **Higher cost and lower quality of ancillary services** – There would be a strong and increasing economic incentive for the developers of new flexible capacity to

⁵ Dated 2nd August 2016

⁶ 18 August 2016, p4, Charging Seminar - Case for change: National Grid Analysis of a Do Nothing Scenario, http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/charging_review/

optimise their generation assets for earning TDR avoidance revenue instead of optimising them to provide economically useful flexibility through ancillary services markets. This may lead to higher prices and risks a shortage of supply of the type and quality of ancillary services required to ensure the energy system remains secure.

- **Higher cost of decarbonisation** – The value of TDR avoidance would increasingly crowd out the economic price signal of the carbon price. This would result in a reducing price elasticity to the price of carbon resulting in higher emissions increasing the long-term cost and challenge of decarbonisation. This distortion is exacerbated by the fact that small EG (below 20MW Thermal) is not subject to EU ETS regulation.
- **Reduced security of peak demand** – The strong economic incentive for developers to optimise new flexible capacity to earn TDR avoidance revenues would also crowd out other price signals provided by the Capacity Mechanism, such as the penalties for failing to deliver capacity for the full duration of a scarcity event lasting up to 4 hours. This may result in the Capacity Market failing to deliver the level of demand security which BEIS may expect.
- **Reduced fuel security** – New capacity optimised to target TDR avoidance revenue will have lower price elasticity to fuel prices, which will tend to crowd out the economic incentive for them to operate with a high thermal efficiency. A GB generation fleet with a lower average efficiency will require a higher volume of fuel to meet peak demand, which would exacerbate the risk of fuel security in the event of the availability of being constrained at a time of peak demand.
- **Worse local environment** – Small scale EG optimised for earning TDR revenue is more likely to result in a GB generation mix with higher environmental emission generators being built closer to concentrations of demand. This will bring more harmful emissions into closer contact with customers with a long-term detrimental impact to public health. This issue is particularly relevant for NOX emissions which are a particular local health issue. For example, smaller scale embedded generator on an industrial estate would tend to be detrimental for local concentrations of NOX, while, by contrast, large transmission connected generators face tougher environmental regulations as well as tending to be located further from centres of demand and dissipating NOX emissions via tall chimney stacks so that it poses much less of a health issue for local air quality.

Chapter 4: Assessment against decision making criteria

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

Yes, we agree with Ofgem's interpretation of the applicable CUSC objectives.

We support the view that CUSC Objective a) 'Facilitating competition' is best achieved by non-discriminatory arrangements that create an equal playing field for smaller EG and other generators. Such arrangements will result in an economic despatch of all forms of generation and, so, will deliver efficient market outcomes and lower consumer costs. Currently TDR payments result in uneconomic investment decisions and out of merit despatch by smaller EG distorting the wholesale energy and capacity market outcomes.

We also agree that CUSC Objective b) 'Cost-Reflective Charging' is best facilitated when all network users face charges which are reflective of their impact on the network cost. We support Ofgem's view that the current TDR payments to smaller EG are not cost reflective because they do not reflect the level of network cost savings that smaller EG deliver.

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

We agree with Ofgem's assessment against the applicable CUSC objectives and statutory duties.

We do not believe that the CUSC Original better facilitates the Applicable CUSC Objectives; however, we believe that certain of the WACMs do. Specifically, WACM1, WACM2, WACM3, WACM4 and WACM5 are better than the Original proposal and are likely to better facilitate the CUSC objectives of cost reflectivity and effective competition compared with baseline. In summary, our case against the Original and some of the WACMs arises from the fact that grandfathering of any level of embedded benefit is not compatible with the applicable CUSC objectives. Our Case against some other WACMs arises from also including an enduring arbitrary non-cost reflective value of embedded benefit ("value of 'x'").

We also support Ofgem's view that **WACM4 (SSE A)** does better meet the CUSC applicable objectives compared with both the CUSC baseline and the Original, particularly with respect to cost reflectivity and effective competition principles. Importantly, this WACM includes the key beneficial features of gross charging of the Demand Residual and no grandfathering so that all EGs are treated the same. This WACM includes the additional beneficial features of (i) providing an embedded benefit equivalent to the value of the avoided GSP cost, which

should result in the TNUoS charging arrangements being more cost reflective, and also (ii) a three year phasing approach which may better facilitate the implementation of the change.

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

No. We support Ofgem's approach where charging arrangements are based on economic principles. We agree with Ofgem's assessment that Economic Impact Assessment is useful to validate the economic principles used, but it should be the underlying economic principles which determine the decision where these principles are clear.

This is particularly important since economic impact assessment by its nature can only assess the impact of a relatively small number of chosen variables. However, in practice if charging arrangements are permitted to diverge from economic principles over an extended period of time, then there are likely to be additional unforeseen detrimental impacts, in addition to those considered in the impact assessment.

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?

Yes, we agree with Ofgem's assessment that no grandfathering should be granted for any selected groups of market participants.

In our view, it would be difficult to reasonably justify any grandfathering for any group of market participants with regard to TNUoS charges. The TNUoS charging methodology relies on providing cost-reflective price signals to all market participants for both investment and closure decisions in order to facilitate effective competition which is required to deliver an efficient outcome for society and the best value for customers. If individual groups obtained grandfathered protection every time the TNUoS charging methodology changed, this would result in an increasingly complicated and increasingly distortionary muddle of price signals not based on the cost reflectivity and effective competition principles. Furthermore, given that TNUoS charges recover costs only from users, if one group of users are immune from their receipt of payments being reduced, or immune from their charges increasing (due to grandfathering), then those ongoing payments, or shortfall in charges (due to grandfathering), must, instead, be paid by all other (non-grandfathered) users. This too has a market distorting and competition impeding effect on those (non-grandfathered) users (who pay the 'shortfall') whilst also affording, as it does, a competitive advantage to the

grandfathered users (who receive the 'shortfall' in the form of receiving non-cost reflective payments and/or not paying the costs they give rise too).

We agree with the position previously stated from Ofgem in this regard. Specifically, in the Open Letter of 29th July Ofgem stated: "We [Ofgem] also think that it may be difficult to demonstrate that the costs and/or fairness of grandfathering the current arrangements for the TNUoS demand residual for existing EG could be justified given the significant costs and distortions that this would likely cause."⁷

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

Yes, we support Ofgem's assessment that the replacement of the TDR payment to EG with the avoided GSP investment cost best facilitates the applicable CUSC objectives, in particular CUSC Objective (b) 'Cost Reflective Charging'. From a cost reflectivity point of view, there may be a case to provide embedded generators with a benefit related to the avoided transmission cost at the GSP, which National Grid has previously estimated (on average, across GB) at circa £1.62/kW per annum.

Separately, we support Ofgem's counter-arguments (outlined in Paragraph 4.52-4.57 of the consultation) in response to the Cornwall Energy analysis which suggested that the value of avoided infrastructure cost delivered by EG is larger than recognised by the avoided GSP infrastructure cost. We agree with Ofgem that Cornwall Energy analysis has a fundamental error of not distinguishing cost recovery charges and cost reflective charges and assuming that EG can save costs in relation to sunk transmission system costs.

We also support Ofgem's view that payments to smaller EG should not be set at the level of TNUoS Generator Residual (TGR). We agree that this feature could only be justified in terms of effective competition (not justified by cost reflectivity) and we support Ofgem's conclusion that the mixed nature of its impact may not be fully consistent with maximising competition. Likewise, an option that proposes to set EG payments at the level of TDR with offshore costs removed is not cost reflective and will not address the distortions created by payments to EG.

Finally, we also support using a "floor to zero" method to ensure that smaller EG do not face a negative TNUoS price signal at Triad which may otherwise have incentivised them to avoid

⁷ Open Letter: Charging arrangements for embedded generation
https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_-_charging_arrangements_for_embedded_generation.pdf

generating during Triad periods. We do not support the approach proposed by WACM6 which offers an alternative method of preventing negative Triad price signals by setting a “value of x” at the lowest locational value. The logic for using the lowest locational is flawed since the value of the price signal would be arbitrary, not cost reflective and sufficiently high in value that it would fail to address the defect. It is also a flawed argument because it would not be beneficial from a cost reflectivity point of view to use the lowest locational value to preserve the full geographical differences in the Year Round tariff element because the differences in the Year Round tariff relate to Year Round conditions, while the value of the lowest locational would be applied only to generation at Triad peak.

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 that changes arising from implementation of CMP264/265 (such as WACMs 3, 4 and 5) that involve larger reductions in payments do not represent a risk to security of supply. We agree that concerns regarding security of supply only relate to certain implementation options and that these concerns add to the case for rejecting these options.

It is our view that it is categorically not the purpose of Transmission charging to incentivise adequate generation capacity or to incentivise dispatch decisions in order to deliver appropriate security of supply. By contrast, this is the purpose of the Capacity Mechanism and the Wholesale Power market. Therefore, the decision regarding which WACM should (or should not) be implemented should not be influenced by any question of its impact on security of supply. In our view, the removal of TNUoS Demand Residual payments will not have unintended consequences on system security. In cases where removal of TNUoS Demand Residual payments results in inability of some embedded generators to recover their short-run marginal costs and leads to their closure, the Capacity Mechanism provides the right incentive framework for the right amount of capacity to remain available or come online on the basis of economic principles (rather than the artificiality of TNUoS cost avoidance).

While we recognise that a short transition period might be beneficial to introduce the change gradually, we do not believe that system security concerns are substantiated, therefore, system security does not provide a sufficient ground for consideration of whether a change to transmission network charging should be implemented.

Finally, we would note that circa 5.5GW of transmission connected generation ceased operation during the last 12 months or so. Various reasons for this were given at the time, including the TNUoS charging arrangements and the changing GB electricity market conditions, of which embedded benefits is a significant contributory factor. Those that seek

to raise security of supply concerns associated with the Original or some of the WACMs appear to 'conveniently' overlook this 5.5GW figure.

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.

No cost savings driven by small EG compared to larger (over 100MW) EG have been credibly identified through the work group process. The classification of embedded generation into smaller (less than 100MW) and larger (more than 100MW) is arbitrary and does not have any bearing on their relative impact on the cost or benefit they may cause for the transmission network.

In our CMP264/265 Workgroup Consultation response, we provided a robust and detailed explanation of why the analysis from Cornwall (indicating a value of benefit at £18.50 per kW) should be rejected and we support Ofgem's rejection of this analysis in their minded to decision. It is further revealing that in their analysis, Cornwall provided no explanation regarding why a smaller embedded generator of say 99.9 MW may, by the nature of its size, cause a cost or benefit which is different from that caused by some other larger generator whether that may be a 100.1 MW embedded generator, or a much larger transmission connected generator at the same geographical location.

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

As we noted earlier, there may be a case, from a cost reflectivity point of view, to provide embedded generators with a benefit related to the avoided transmission cost at the GSP.

We note that some WACMs include a new value of embedded benefit which will remain applied on a net basis. The Workgroup referred to this value as the "value of 'x'". This new benefit within the CUSC can only be justified if it meets the CUSC applicable objectives and, in particular, if it is cost reflective and/or facilitates effective competition. It is our view that some of these features could be justified in line with the CUSC applicable objectives, while others cannot, as described below:

- 1) **Justifiable – Value of 'x' at Negative of the Generator Residual** – It is our view that, in order to better facilitate effective competition, a value of the transmission generator residual could be applied as an embedded benefit. This may provide a more level playing field between embedded and transmission connected generation with respect to the value of the generator residual. This approach may avoid an

imminent need to change the way the generator residual is calculated and would enable any potential changes to the Generator Residual in the future to be automatically incorporated. However, we appreciate the balanced nature of the benefits of this feature and support Ofgem's conclusion that this may not be fully consistent with maximising competition.

- 2) **Unjustifiable – (i) Do not use lowest locational charge** – This feature would result in an arbitrary value of embedded benefit and would fail to correct the defect, with regard to either cost reflectivity or effective competition, because:
- a. **It continues to distort competition** - it would result in an ongoing arbitrary and large value of embedded benefit whereby generators which happen to be connected to the distribution network would continue to receive a substantial revenue stream which is not available to other generators who may be otherwise identical, but who happen to be connected to the transmission network. Therefore, the existing CUSC baseline distortions to investment and dispatch decisions and redistribution would persist.
 - b. **It is not cost reflective** – It cannot be justified in terms of the CUSC applicable objectives of cost reflectivity or effective competition. The key justification provided for this approach is not valid, namely, the intention to maintain the full locational gradient of tariffs instead of flooring the Year Round tariff at zero. This is because the current locational transmission tariff gradient is dominated by the gradient of the Year Round tariff element, but it is not cost reflective to apply the Year Round tariff to the peak (Triad) generation of an embedded generator, so the objective of using this feature to preserve the slope of the existing Year Round tariff gradient does not result in the relative locational price signal of the embedded benefit being any more cost reflective.
 - c. **It may be greater magnitude of distortion than baseline** - It is also possible that future changes in the gradient of locational transmission charges may result in the value of the lowest locational tariff becoming even greater magnitude than the Demand Residual would have been if the baseline charging methodology had been retained.
 - d. **It is likely to be volatile** – Changes to the value of locational transmission tariffs, particularly at the extremes such as the lowest locational value have historically demonstrated to be volatile. Therefore the value of this new benefit would likely be volatile and difficult to forecast and would therefore not provide a good signal for investment.

- 3) **Unjustifiable – (ii) Do not use an arbitrary value of “x” based on historic levels –** There is no justification within the CUSC applicable objectives for maintaining an arbitrary value of “x” at some level based on what this value happened to be at some time in recent history. It is the objective of the TNUoS charging methodology to provide TNUoS tariffs which are cost reflective and which facilitate effective competition. By contrast, it is not the purpose of TNUoS charging to “pick winners” by protecting the investment decisions of one or more specifically selected groups of investors (e.g. protect generators who happen to be embedded, but not provide that same protection to other generators who happen to be transmission connected). TNUoS tariffs and the charging methodology, which these tariffs are based on, has and does continue to change substantially from year to year, so generators cannot reasonably claim to have a valid expectation that any specific historic level of TNUoS could be ‘banked’ on for any number of future years, let alone for the full duration of their project life. We agree with the positions previously stated from BEIS in this regard⁸. Specifically, we agree with the recent comments from BEIS in their Capacity Market consultation which address the same principles and which are also applicable to this TNUoS charging modification: “However, to the extent that an investor/CM participant assumes a future revenue as a result of embedded benefits from a CM levy, they ultimately do so at their own risk; and as such they should factor in the possibility that this levy could be subject to change in future and discount it accordingly, as with other variables that an investor needs to consider.”
- 4) **Unjustifiable – (iii) Do not use selective exclusion of Demand Residual cost elements –** We would suggest that a selective exclusion of individual elements from the Demand Residual net charging base, such as OFTO charges, would be arbitrary and discriminatory. In our view, the entire cost of the Demand Residual should be applied gross. The suggested rationale for excluding OFTO costs, because they are driven by environmental policy and are not avoided by embedded generators, could be applied equally to all other cost elements, including onshore reinforcement being made principally to support connection of other low carbon technologies. The costs caused or avoided by individual embedded generators are reflected in the locational

⁸Government response to Capacity Market consultation, [Detailed proposals - Capacity Market: proposals to simplify and improve accessibility in future capacity auctions](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/563444/CM_Consumption_detailed_proposals.pdf), March 2017.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/563444/CM_Consumption_detailed_proposals.pdf

elements of the TNUoS tariffs and by contrast not reflected in any individual line item of the non-locationally allocated TNUoS Allowed Revenue.

- 5) **Unjustifiable – iv) No valid evidence has been provided to justify some other value of “x” on the basis of cost reflectivity** – The conclusions in the report carried out by Cornwall⁹, which claimed to calculate a missing value of embedded generation, are not valid and can not be relied upon. We explain our reasons for this in more detail within this response in our answer to Question 7 and 9. We also gave further detail in our response to the Workgroup Consultation¹⁰. It is our view there was no valid justification presented to the Workgroup to support some other value of “x” on the basis of the applicable CUSC objectives of cost reflectivity or effective competition.

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

No. We agree with Ofgem that TNUoS charging arrangements can and do change from time to time subject to the CUSC. We agree that the changes proposed by the WACM 4, directed to be made in Ofgem’s minded to decision document, were very predictable for developers who had carried out due diligence regarding the evolution of Transmission Network Use of System Charging. Developers should expect Ofgem to approve changes to the CUSC which better meet the CUSC objectives and Ofgem’s wider objectives. We also agree that if Ofgem, or any regulator, made decisions which went against their own rules, then this unpredictable regulator behaviour would be a larger threat to developer risk margins and industry confidence.

It should be remembered that the decision to charge Demand Residual on Triad demand was made¹¹ at a time when the demand residual was a small number and there was a perceived need to increase the incentive to reduce energy consumption at peak times through indirect means due to the limited presence of other signals for reducing peak energy demand rather than as an appropriate means of giving an incentive to reduce investment in Security related transmission capacity. In the current market, the appropriate price signal for dispatching demand during peak periods is provided by the wholesale power price and the Capacity Mechanism.

⁹ Cornwall, A Review of the Embedded Benefits accruing to Distribution Connected Generation in GB

¹⁰ Volume 3 Workgroup Consultation Responses, SSE Response, Question 18, page 645 to 650

¹¹ Transmission use of system charges review, proposed investment cost related pricing for use of system, 30th June 1992

Chapter 5: Distributional Issues

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

Yes, we agree with Ofgem's assessment of the distributional issues outlined in the consultation document. It is our view, in line with Ofgem, that the impacts of the change are not disproportionate and are justified by the benefits they provide.

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

In our view, the assessment is comprehensive and provides examples of potential impacts for an appropriate range of assets.

A key sector, which could have been given even greater emphasis, would include the relatively large benefit to vulnerable customers from Ofgem's minded to decision. Vulnerable customers are facing a disproportionately high share of the cost of the TDR embedded benefit and this group would continue to become disproportionately worse if the defect is not addressed urgently. This is because, firstly, the value of the TDR embedded benefit results in a higher cost of the transmission system, while, secondly, a higher cost to customers results from having to pay the value of the TDR embedded benefit, while, thirdly, this provides a progressively stronger incentive for sophisticated customers to avoid Triad periods. These three factors together tend to result in the most vulnerable customers who are least able to avoid paying TDR charges paying disproportionately much more than they otherwise should be if Ofgem's minded to decision was implemented.

Chapter 6: Quantitative modelling results

Question 14: Do you agree with our modelling approach?

Yes we agree with Ofgem's modelling approach. We support the view that a principles-based qualitative assessment should provide the basis for considering the changes to the GB charging regime. We also agree that a quantitative assessment of possible consumers and system costs and savings should be supporting qualitative principles and assessment.

We support the five groupings adopted by Ofgem to assess 23 proposed WACMs, including the Original, and the additional modelling of impacts of phasing and grandfathering.

We do, however, consider that the assumption of the Status Quo TDR becoming flat real beyond 2021 is misleading. This will have substantially under stated the long-term benefit of

moving away from the status quo. This approach will therefore be very conservative and will have substantially underestimated the economic benefit of CMP264/265.

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

Yes, we agree this is appropriate. We also agree that the use of a different set of assumptions may result in a different (higher, or lower) result of the economic impact assessment, however, this should not affect Ofgem's decision. The economic impact assessment is a useful tool for understanding the range and direction of potential issues. The results of such an assessment provide an appropriate basis for a thorough consideration of the available options.

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

Yes, we agree that it is not proportionate to model all of the options directly and, therefore, in our view, it is appropriate to use the modelled scenarios as a proxy for those not modelled directly. We are satisfied with the modelling options outlined on page 104 of the consultation document (Appendix 8) and the approach of using the closest scenarios to replicate the background build out and estimations for scenarios not modelled directly.

Chapter 7: Assessment of shortlisted options

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

In our view WACMs 1 to 5 all facilitate the applicable CUSC objective better than the Original. Out of the three shortlisted options (WACM 3 – WACM 5), we support Ofgem's conclusion that WACM 4 best facilitates applicable CUSC objectives.

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

Yes, we consider that it is important that Ofgem's decision regarding CMP264 and CMP265 is implemented as soon as practicable so that customers obtain the benefit without delay. We agree that the April 2018 date best facilitates the applicable CUSC objectives. In our view,



the phased approach avoids cliff edge issues and provides the time needed for all participants to adapt to the new arrangements.