



Frances Warburton
Partner
Energy Systems
Ofgem
9 Millbank
London
SW1P 3GE

Head Office
Inveralmond House
200 Dunkeld Road
Perth
PH1 3AQ

polina.kharchenko@sse.com
01738 512072

23 September 2016

Dear Frances,

Open letter: Charging arrangements for embedded generation

We would like to take this opportunity to share our views on the issues outlined in Ofgem's Open Letter on charging arrangements for embedded generation of 29th July 2016.

Distortions to the charging arrangements for embedded generators have important implications for the efficient provision of flexibility for the energy system. We support Ofgem's view that the increasing scale of embedded benefits, and TNUoS demand residual payments in particular, are distorting the market and should be addressed as a matter of priority. Our view on possible remedies is outlined in Section 3 and 4 of the response.

Specifically, while supporting certain elements of CMP264/265, we believe that some of the alternatives that the CUSC Workgroup are, at the time of writing, considering, such as "SSE A", "SSE B", "Centrica B", "Uniper A", or "NG C" are better than the original CMP 264/265 proposals and are likely to better facilitate the cost reflectivity and effective competition objectives.

In our view, TNUoS Demand Residual should be based on the principles where those charges should be fair and difficult to avoid so that this charging element meets its purpose of revenue collection while treating customers in an equitable way. If TNUoS Demand Residual payments are removed as an embedded benefit, then the unit cost of the transmission



system which consumers are paying for would be reduced and this “quick win” approach to improving charging arrangements could deliver benefits for customers much sooner than otherwise would be the case.

We would suggest that any modifications to charging arrangements should take place through the existing industry modification processes which have been developed over time by Ofgem¹ together with stakeholders and reflect the applicable objectives plus have the appropriate checks and balances to better deliver solutions which are in the best interest of consumers.

Kind regards,

Polina Kharchenko

Regulation Manager, Wholesale

¹ Via, for example, its Code Governance Reviews.

1. Principle-based charging arrangements

In our view, it is essential that for all types of charging arrangements, 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:

(1) Category 1: Economic price signal (e.g. TNUoS Locational tariff elements)

This signal from this category of charges should be consistent with the CUSC objectives² of cost reflectivity and effective competition. In this way it fulfils its role of promoting the efficient operation of the power market by providing appropriate and economically efficient investment, or dispatch signals to those users that export to the network (such as generation) and those users that import from the network (such as demand). For those objectives to be achieved, charging elements should be applied to an appropriate charging base so that users, be they importing or exporting to the network, are exposed to economic incentives which reflect the incremental costs to the network which they cause.

Charges for the purpose of sending an economic price signal may collect a net non-zero revenue amount (net revenue collection may be positive, or negative), which is entirely appropriate and highlights the need to apply a separate charging element in order to ensure the required total revenue is collected.

(2) Category 2: Revenue collection (e.g. TNUoS Demand Residual)

This principle for this category of charges follows the 'optimal tax theory' where the methodology for revenue collection should be fair and difficult to avoid. In other words, (i) 'fairness' could include revenue collection proportional to the ability to pay, or proportional to the value which individual parties receive from the services, or some other method deemed equitable by society; (ii) 'difficult to avoid' means that resources should not be expended to avoid paying the charge because this avoidance action, similarly to tax avoidance, would tend to result in an economically inefficient outcome and higher costs to customers over the long term. By comparison, an action taken to avoid paying a charge is only useful to society if that particular charge is an explicitly cost-reflective economic price signal.

² Designated by the Secretary of State at NETA and BETTA, and amended, from time to time, by the Authority.

Separately, in certain cases other principles should be taken into account to reach an optimum structure of the charging methodology. These include the principles of transparency, accuracy, stability and predictability. We believe that the current charging arrangements, in relation to TNUoS Demand Residual in particular, are not consistent with the above-mentioned principles.

The approach of the current net charging arrangements, where embedded generation is charged as if it is negative demand, can be appropriate in circumstances where the demand charge is cost-reflective. However, it is important to consider that, in some situations, it may not be appropriate to apply cost-reflective charges on a net basis. This is because different charges may be designed for different purposes. For example, the TNUoS generation locational charge has the purpose of providing a locational investment signal to generators. By contrast, the TNUoS demand locational charge has the purpose of providing both a locational dispatch signal as well as a locational investment signal for demand. Further, if the purpose of a charging element is to collect revenue (effectively tax) from demand, then in this circumstance, it is difficult to justify the use of net charging where, for example, a similar size (MW) of generator (embedded generation) obtains a benefit from avoiding a tax, while another generator (transmission connected) also of a similar size (MW) does not obtain the same benefit, despite the impact of both generators on the cost of the system being the same.

2. TNUoS Demand Residual payments – Market distortion

The demand part of the TNUoS charging methodology³ includes two key tariff components of the wider tariff: (i) the TNUoS Locational tariff (made up the Peak Security tariff element and the Year Round tariff element), and (ii) the TNUoS Demand Residual tariff. The current Triad charging methodology incentivises investment and dispatch decisions for embedded generators located both on the distribution network and behind the demand meter, as well as genuine demand reduction in order to avoid paying the Demand Residual element of the TNUoS tariff. We support Ofgem's view that the increasing scale of embedded benefits, and TNUoS demand residual payments in particular, are distorting the market and preventing a level-playing field.

As described earlier, the TNUoS Demand Residual is effectively a form of tax for revenue collection, not a cost-reflective price signal, because it does not reflect the avoided investment cost of the Transmission network. We support Ofgem's view that the price

³ Set out in Section 14 of the CUSC.

incentive to avoid the TNUoS Demand Residual represents a distortion to the efficient operation of competitive markets resulting in the following market defects:

- 1) Inequitable redistribution of transmission costs between different customers;
- 2) Inequitable redistribution of transmission costs between customers and generators;
- 3) Economically unjustified subsidy to embedded generation (EG) which tends to distort competition in the capacity market. For example, EG may obtain a capacity contract despite being out of economic merit;
- 4) EG dispatch out of economic merit putting a downward pressure on wholesale energy prices and displacing transmission connected generation (TG) out of the merit order; and
- 5) TRIAD becoming an economically inefficient price signal as EG is running for longer periods and the timing of TRIAD periods becomes more uncertain.

3. TNUoS – Benefit from avoidance of Demand Residual – Possible remedies

3.1. CMP 264 / 265

In our view CUSC modifications CMP264⁴ and CMP265⁵ Original proposals raised by industry stakeholders do attempt to address some of the above-listed market defects with the current charging arrangements. However, we would suggest these proposals do not go far enough. Both of the original proposals have certain limitations and we consider that some of the alternatives would better meet the CUSC objectives and Ofgem's wider objectives.

In relation to **CMP264**, its implementation would facilitate the cost reflectivity and effective competition principles only to extent as discrimination between existing EG and new EG as well as all TG would remain. In addition, CMP264 would have limited effect on the TNUoS charges of existing EG and their uneconomic despatch and delayed closure decisions would continue to distort (i) wholesale energy prices, (ii) new market investments and (iii) the capacity market outcome. Furthermore, CMP264 would not rectify the inequitable redistribution of transmission costs between customers and existing EG - customers would continue to pay for the embedded benefit available to existing EG.

In relation to **CMP265**, we think that this proposal while aiming to facilitate effective competition in the Capacity Market might introduce certain unintended consequences. For example, taking into account that TNUoS Demand Residual payments are much larger than the CM clearing price, EG might opt to forgo CM revenue for the benefit of receiving

⁴ <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/>

⁵ <http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/modifications/Current/>

embedded benefit payments instead. This could result in further distortion and reduced competition in the Capacity Market which would further diminish its effectiveness. Furthermore, similar to CMP264, CMP265 does not rectify the inequitable redistribution of transmission costs between customers and those EG without CM contracts.

While supporting certain elements of CMP264/265, we believe that some of the alternatives that the Workgroup are, at the time of writing, considering, such as “SSE A”, “SSE B”, “Centrica B”, “Uniper A”, or “NG C” are better than the original proposals and are likely to better facilitate the cost reflectivity and effective competition objectives.

3.2. Beneficial characteristics of WACMs

The following points summarise our views regarding the merits of the different elements described in the WACMs for CMP264 and CMP265:

- 1) **Demand residual** – It is appropriate that this element is charged gross on all embedded generators as per the SSE, Centrica and Uniper WACMs. The purpose of the Demand Residual is effectively to collect revenue through a form of tax, therefore it is not appropriate that embedded generators are able to avoid this tax and obtain a benefit through net charging of this tariff element.
- 2) **Locational tariff elements** – It is appropriate that the locational tariff elements remain charged on a net basis and, as an interim solution, it is appropriate that the value of the embedded benefit is floored at zero. In our view it is not cost-reflective to apply the Year Round tariff to a peak charging base (such as Triad) and a subsequent modification should consider an alternative demand charging base. In our view it would not be appropriate to apply a negative Year Round price signal to embedded generators at Triad because this could provide a perverse incentive for EG to turn down at peak, despite the tariff element reflecting year-round conditions. Moreover this could drown out a potential positive Peak Security tariff sending the opposite signal to EG to generate at peak to support the transmission network.
- 3) **Avoided GSP cost** – 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, which National Grid has previously estimated at circa £1.62/kW per annum. If this element is applied net as an embedded benefit, it will be important to review the value of this benefit and consider the most appropriate way it could be applied.
- 4) **Phased transition** – A phased approach may provide a helpful transition period for the System Operator and other market participants to adapt to any potential

changes in the behaviour of embedded generators following a change to the Triad signal. An early transition will also reduce the cost to customers by reducing the total cost of embedded benefits from as early as possible before the lower level of the enduring solution is implemented. We would support a short-phased approach as described in both the “SSE A” and “SSE B” WACMs, where a short phased period begins as early as practicable (such as the 2018/19 charging year).

- 5) **Implementation date** – We consider that it is important that Ofgem’s decision regarding CMP264 and CMP265 is implemented as soon as practicable. We would suggest that it may be more beneficial for all market participants and customers if the issues related to charging are addressed through a step-by-step approach. We believe Ofgem has a valuable role to play regarding setting out the vision and the key principles by which changes should be considered, however it would be more practicable to consider changes in smaller groups with regard to issues and to the stakeholders affected. By contrast, if Ofgem attempted an SCR process to address all matters related to charging at the same time, then there would be a substantial risk that this “all or nothing” approach could take an unacceptable length of time and would crowd out the opportunity for implementing “quick win” improvements to charging arrangements which could otherwise deliver benefits for customers much sooner.
- 6) **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 changes in the future to be incorporated.
- 7) **No 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 equally applies to all other cost elements, including onshore reinforcement for other low carbon technologies. The costs caused or avoided by individual embedded generators are reflected in the locational elements of the TNUoS and not in any of the elements of

the Demand Residual. Allowing certain users to, arbitrarily, avoid a change will distort competition between similar users of the network and thus could be contrary to both EU competition law and state aid requirements.

- 8) **No grandfathering for selected groups** – We agree that 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 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 complicated and distortionary 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 paying such a charge (due to grandfathering) then those unpaid 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.

4. Better cost reflectivity of the TNUoS demand tariff methodology

The changes proposed by CMP264, CMP265 and some of the associated WACMs can address the largest existing market distortion arising from TNUoS Residual Demand payments and should be introduced as soon as practicable. However, these proposed remedies still only represent a partial solution with regard to embedded generators. In our view, it will be beneficial to make further improvement to the TNUoS demand charging methodology to correct the remaining market distortions with regard to behind the meter generation and demand.

As CEER⁶ set out earlier this month in the Q&A to their Position Paper⁷: “Consumers exclusively relying on the network for their energy supply should not be unduly disadvantaged compared to those consumers engaging in self-generation, and all consumers should face relevant price signals”. It will be also beneficial to take the lessons learned from Project TransmiT (CMP213) regarding generation charges and apply those lessons to the

⁶ As noted on their homepage “CEER is the “Council of European Energy Regulators”. It is the voice of Europe's national energy regulators at EU and international level. Through CEER, the national regulators cooperate and exchange best practice.”

⁷ CEER Citizens' Q&A, CEER Position Paper on Renewable Energy Self-Generation, September 2016: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2016/C16-SDE-55-03b_Renewable%20Self-Consumption_QA.pdf

demand TNUoS charging methodology. These changes should follow the key principles described above.

As noted previously, the TNUoS Demand Residual charging should follow the principles of 'revenue collection' or 'optimal tax theory' where it should be fair and difficult to avoid. Hence in our view further consideration should be given to the **charging base** which TNUoS Demand Residual is being collected from. A different charging base, other than Triad demand, would better meet the principles of being difficult to avoid and being fair. This charge could reflect the value of the 'insurance benefit' to each customer which having access (at any time of their choosing / needing) to the transmission network provides.

For collecting the Demand Residual element from customers, it may be beneficial to move towards a "Smart Triad" charging base to reflect the peak demand of each customer. This approach would be similar to the way TNUoS charges are currently applied to transmission connected generators which are located in negative charging zones:

- **Half Hourly customers** – For each customer, their "Smart Triad" demand could be based on the average of the three highest half hours of their demand per year during the time window 6am to 8pm for every day of the year.
- **Non Half Hourly customers** – For non half hourly customers, their "Smart Triad" charge could be based on using existing customer type profiles to calculate a charge equivalent to that of a Half Hourly customer based on the implied average of the three highest half hours of their demand.

This "Smart Triad" approach would address the issue that even if a customer largely avoids consuming electricity from the transmission network most of the time (including the 'traditional' Triad), the transmission network is still available to them if they need it throughout the year. Therefore charging the Demand Residual based on each customer's actual peak demand (kW) over a year will better reflect the value to each customer of the 'insurance benefit' they receive from the having access to, and using (over the whole year), the transmission network. To avoid the £/kW charge, customers would need to reduce their demand on a sustained and ongoing basis rather than simply reduce their demand over a small number of half hours per year (as per the 'traditional' Triad arrangements). This would reduce the market defects caused by TNUoS Demand Residual avoidance.

We would also suggest that the Year Round tariff element could be collected from a different demand charging base which better reflects year-round demand. It may be appropriate to take lessons from CMP213 which applies the Year Round tariff element on

transmission connected generators through an Annual Load Factor (ALF). An equivalent to this may be to apply the demand Year Round tariff on a commoditised £/MWh basis.

It may also be beneficial to consider the most appropriate charging base to apply the Peak Security tariff element to demand. An appropriate charging base should reflect demand at times of system peak, for which the existing Triad definition may remain appropriate. However, it would be beneficial to consider alternative approaches, for example, a longer window such as that used by the Capacity Market levy of 4pm to 7pm over the Winter Weekdays.

It is also important to consider the implications of CMP266⁸ which relates to the transition of NHH customers to HH metering / settlement / charging arrangements. One of the alternatives being considered within CMP266 would begin exposing an additional group of customers (who have transitioned from NHH) to HH Triad price signal as early as April 2018. If this transition was applied before the Demand TNUoS Triad charging arrangements were reformed, then this could significantly exacerbate the Triad problem which Ofgem has identified. Namely that it would drive economically inefficient Triad avoidance behaviour from even more customers which would further increase the cost of TNUoS on those remaining NHH customers. Given the volume of customers that it is planned (via the Smart Meter rollout) will be moving over to HH (from NHH) annually up to 2020 this effect (for those NHH customers that remain) may not be trivial or inconsequential.

5. Implications of changes to charging arrangements

Maintaining Security of Supply

In our view the removal of TNUoS Demand Residual payments will not have unintended consequences on system security. The changes to network charging arrangements will not affect the system margin as long as embedded generators remain available and dispatch based on their economics in the merit order. 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 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,

⁸ <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP266/>

therefore system security does not provide a sufficient ground for consideration of whether a change to network charging should be implemented.

Addressing Exporting Grid Supply Points (GSPs)

In our view if demand charges are improved in the way described above, then this can provide a more cost reflective charging methodology for all demand and generation users of the network irrespective of whether or not they may be located behind an exporting GSP. If TNUoS charges are applied in an appropriately cost-reflective way, it would no longer be necessary to consider special solutions for exporting GSPs.

Reducing customer impact

If TNUoS Demand Residual payments are removed, the cost of the transmission system which consumers are paying for would be reduced.

The largest and most important benefit to customers is the reduction of the cost which customers are currently paying for the embedded benefits. The National Grid analysis (Figure 8 of CMP264/265 workgroup consultation⁹) suggests that the value of TNUoS Demand Residual embedded benefit, which customers 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 situation was permitted to continue, the cost to 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 would amount to 70% of the entire cost of the Transmission network compared with its current level in 2016/17¹⁰.

It is clear that a move towards more cost reflective price signals would result in competitive markets delivering a more economically efficient result at a lower total system cost, and therefore at a lower cost to end customers (regarding both network cost and generation cost). It is reasonable to expect that this lower total system cost would result in even greater reductions in cost to customers over the medium and longer term.

Improving Markets

It is our view that each charging arrangement and market mechanism should provide price signals which are cost reflective in their own right because this will incentivise decisions

⁹ Dated 2nd August 2016

¹⁰ 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/

which tend to result in a more efficient outcome, therefore lowering costs to customers over the longer-term. By contrast, it is not appropriate to consider the use of one charging methodology, such as TNUoS, to cross-subsidise the prices which arise from a different market mechanism such as the Capacity Mechanism, or Wholesale power market, because this will tend to result in inefficient decisions and higher cost to customers over the longer term.

A reduction in the value of the Triad avoidance embedded benefit may result in changes to the clearing prices of other markets such as the Capacity Market and Wholesale power markets. However, we would suggest that any resulting changes to these markets would represent a move to more appropriately efficient levels than would otherwise be the case. A meaningful impact on these markets would highlight how large a distortion the current network charging methodology may be.

We note the analysis carried out in relation to the consumer impact of a potential increase in the clearing price of these other markets. For example, Cornwall¹¹ suggests the cost of the capacity market could increase from c. £214m in 2019/20 to £282m in 2020/21. However, when compared with National Grid's analysis, a potential saving to customers from the reduction in Triad payments to embedded generators of £343m to £2bn would greatly outweigh the potential increase in Capacity Mechanism cost that Cornwall's analysis suggests.

It is also important to consider distributional affects between different types of customers. The reduction in the cost of TNUoS charges would predominantly benefit Half Hourly customers and to a lesser extent domestic customers who tend, currently, to be NHH (because half hourly customers disproportionately avoid paying Triad charges), while an associated increase in the cost of the Capacity Mechanism apply more evenly to both Half Hourly and Non-Half hourly customers equally.

It is important to note that if the reduction in the value of the embedded benefit were only applied to a sub set of embedded generators, the subsequent cost saving to customers would not be as large. We would question the justification for continuing to charge customers an additional cost in order to pay the value of the non cost reflective demand residual to a sub set of embedded generators.

¹¹ http://www.theade.co.uk/embedded-benefits-review--manufacturing-energy-cost-concerns_4069.html

6. Other charging arrangements

We support Ofgem's view that the Demand Residual embedded benefit represents the largest and most important current distortion to the market and should be addressed as a matter of priority. We also agree that there are other embedded benefits which are also currently causing distortions to competition and therefore should be addressed as soon as practicable. In our view it would be appropriate to apply the key principles described in Section 1 of this response to other forms of charging. We outline our further views on this below.

BSUoS charging

We agree with Ofgem that BSUoS may be best described as a largely revenue collection mechanism which is equivalent to a form of taxation. In this case then, applying the principles outlined in Section 1 of the response, BSUoS charging should be equitable and difficult to avoid. In this context, it would be difficult to justify a double BSUoS benefit that embedded generators currently receive: (i) not paying BSUoS themselves, whilst other parties, including transmission generation and demand, do pay this charge; and (ii) embedded benefit arising from net charging of demand BSUoS which must, in turn, therefore be paid for by other market participants through even higher BSUoS charges.

Capacity Market supplier levy

The net charging of the Capacity Market levy causes an additional market distortion because it provides a benefit to embedded generators which is not available to transmission connected generators. We understand that BEIS will be considering how this may change in the future.

Low carbon levies

In our view, further market distortion is currently caused in the scenarios where low carbon levies are not applied on behind the meter generation. Green levies could be viewed as a form of tax to recover the cost of societally supported arrangements associated with wider (non-electricity industry specific) climate change obligations; such as the low carbon support schemes; and therefore should be applied fairly and in a way that is difficult to avoid.

Current charging arrangements mean that it is possible for customers to avoid paying these taxes by generating their own electricity behind their own demand meters and therefore consume power which is not taxed instead of purchasing power from the network, on which the taxes are applied.

This tax avoidance behaviour results in the same total cost of the schemes being recovered from a shrinking taxable charging base, therefore the unit rate of tax increases on all remaining customers. This arrangement also provides a tax arbitrage opportunity for behind the meter storage where customers are able to use storage to arbitrage between their onsite generation (at a low price because it is tax free) compared with power from the grid which is more expensive because it is 'taxed'. Vulnerable customers are likely to be least able to avoid paying the charges so are likely to end up paying an increasingly larger share of the societal costs of these schemes on behalf of other customers.

Whilst recognising that the collection of low carbon levies is a policy issue, we believe it is important that Ofgem forms a position on this in the best interests of customers in general, and vulnerable customers in particular.

Balancing Mechanism cash-out prices

While beyond the scope of Ofgem's Open Letter, it is important to consider how the application of Balancing Mechanism cash-out prices may provide distortionary charges for embedded generation.

The cash-out prices are designed to provide an efficient cost reflective price signal. However, it appears that the magnitude of the price signal differs depending on how an embedded generator is connected to the network in a way which does not reflect differences in cost. Current cash-out arrangements result in parties providing balancing services being 'paid as bid', while parties out of balance are charged on a 'paid as cleared' basis.

The above difference means that the cash-out price faced by parties out of balance will tend to always be more valuable to them than the cash-out price paid to other parties who do provide balancing service by competing in the Balancing Market. This difference currently provides a distorted price signal for dispatchable embedded generation to co-locate behind a generation meter (of a non-firm generator such as wind, or PV) so that they are able to self dispatch within the gate closure period and in this way avoid competing with other generators in the Balancing Market. This means that behind the meter generators become able to directly access the more valuable "paid as cleared" cash out prices, sometimes referred to as "NIV chasing", despite these prices not being available to otherwise identical generators who are connected directly to the distribution or transmission network instead.

Transmission losses

The application of transmission losses represents an additional double benefit available to embedded generators. Firstly, applying the principles outlined in Section 1 of this response,

if a purpose of transmission losses is to collect the cost of system losses in a fair way, it may be difficult to justify why the class of generation identified as embedded does not pay a share of transmission losses while all other generation and demand does. Secondly, the treatment of embedded generation as negative demand means that embedded generators get paid for avoiding demand transmission loss charges. This is not in line with the 'no avoidance' principle of revenue collection as outlined in Section 1.

DUoS

When considering network charges and their impact on effective competition between all market participants, it will also be important to consider distribution charges, such as DUoS, and how these may be improved to be more cost reflective.

Interconnectors

To further facilitate effective competition, key principles and distortions identified in relation to embedded generation charging should also be considered in relation to the charges paid (or rather, currently, not paid) by interconnectors.

Currently interconnectors may cause system costs related to (i) transmission investment, (ii) balancing services and (iii) transmission losses. However, interconnectors are not exposed to the cost reflective price signals which relate to these system costs and therefore this may distort their investment and dispatch decisions, particularly when compared with other market participants (such as generators or demand) who are exposed to those costs. In addition, interconnectors are also not exposed to the revenue collection elements of TNUoS, transmission losses and BSUoS which may, over time, as the volume of interconnectors grow cause a "death spiral" effect similar to the one caused by embedded generation behind demand meters. Furthermore, interconnectors may, for example, displace GB generation capacity and volume which will result in a shrinking charging base from which these TNUoS, transmission losses and BSUoS costs can be collected. This may, in turn, increase the unit rate of these charges on all other remaining market participants and drive a feedback loop of declining investment and dispatch of GB generators.

7. Implementation approach

We would suggest that any modifications to the GB charging arrangements should take place through the existing industry modification processes and not a new 'project board' type group. Existing industry change processes have been developed over time by Ofgem¹² and stakeholders to include appropriate objectives, as well as suitable checks and balances

¹² For example, via their Code Governance Reviews.

to better deliver solutions which are in the best interest of the industry and the best interest of customers. By contrast a new 'project board' may lack the rigorous governance rules, openness and transparency with regard to objectives and processes and be less transparent regarding the interests of the individual members of the 'project board'. Also, it may be unclear whether the members of such a 'project board' may have sufficient detailed technical expertise which would be required to adequately oversee the detail of any proposed changes with regard to these types of charging arrangements. There could also be a concern that a 'project board' of this type may also not be able to provide sufficient regular time commitment to remain on top of the developments which can change quickly during a modification process.

8. Conclusion

Distortions to the charging arrangements for embedded generators have important implications for the efficient provision of flexibility for the energy system.

It is important to recognise that all of the distortions identified in this response as well as in the Ofgem's July Open Letter may tend to (perversely) incentivise the wrong types of technologies to be built at the wrong scale at the wrong locations in GB. The market distortions may also incentivise technologies to then dispatch at the wrong times for the purpose of 'tax avoidance' (of one or more of the various charging elements identified in the Open Letter and this response) instead of in accordance with the genuine underlying economic value (which arise where these perverse incentives are absent).

Some market participants may take the view that the use of implicit subsidies through net charging to avoid effective taxes may not be ideal, but that it is possible that flexible capacity incentivised through this framework may be better than nothing. However, to the contrary, we would suggest that investment and dispatch decisions incentivised by such large distortions to charging arrangements may well result in decisions which destroy societal value, have a distortionary effect on competition and / or affect cross border trade¹³ as well as lead to unintended consequences.

¹³ Contrary to UK and EU law, such as set out in paragraph 2.21 of Ofgem's Enforcement Guidelines (12th September 2014).