



Response to Open Letter on charging arrangements for embedded generators

23 September 2016

Context

The Association for Decentralised Energy and the Renewable Energy Association welcomes the opportunity to respond to Ofgem's Open Letter on charging arrangements for embedded generation.

The ADE is the UK's leading decentralised energy advocate, focused on creating a more cost effective, efficient and user-orientated energy system. The ADE has more than 100 members active across a range of technologies, and they include both the providers and the users of energy. Our members include industrial manufacturers, local authorities, and energy service providers, and have particular expertise in combined heat and power, district heating networks and demand side energy services, including demand response and storage. Our members include both transmission and distribution connected generators.

The REA represents a wide variety of organisations, including generators, project developers, fuel and power suppliers, investors, equipment producers and service providers. It has over 700 corporate members, making it the largest renewable energy trade association in the UK.

In addition to this response, the Association for Decentralised Energy (ADE) has commissioned NERA Economic Consulting (NERA) to review Ofgem's Open Letter on charging arrangements for embedded generation, alongside analysis from Imperial University on the current causes of the TNUoS demand residual. This response has been submitted separately.

Executive summary

We are concerned that Ofgem is focussed on equalising charges to improve the economics of specific market players in the Capacity Market, and that proposals to move to gross charging for embedded generators attempt to make the costs of using different networks comparable, akin to trying to equalise fuel costs between different types of generation.

It is vital that Ofgem plays an independent, active and analytical role in any review process, rather than relying on individual CUSC modifications. An Ofgem-organised and independently-led review of Embedded Benefits should be integrated with National Grid's project to reform transmission charges to engender a careful, holistic and systematic approach, across both the transmission and distribution networks, and help deliver an enduring solution.

Under CMP264 and CMP265, Ofgem risks finding itself in a regulatory cul-de-sac, unable to fix new distortions which it had just created for on-site generators and demand reduction. More easily implementable solutions, which directly address the TNUoS demand residual, are available.

The TNUoS demand residual is not, as the Ofgem letter states, "largely fixed and sunk costs". The residual is a cost recovery mechanism, required because there are costs accrued on the network

which have not been allocated to specific users. The level of the residual is arbitrary, based on a number of decisions made regarding the size of the locational charge's cost recovery, which currently only recovers 10% of network costs. Therefore distributed generators, by reducing demand on transmission networks, could be seen to have an impact on the costs captured within the residual charge.

It would be more appropriate for Ofgem to address the level of the triad charge caused by the fast-rising demand residual, rather than the benefit received by distributed generators. We believe three steps would help address the fast-growing demand residual:

- Reduce the demand residual by reviewing the size of the money recovered from the locational charge, which is currently limited to just 10% of the overall costs of the network.
- Reduce the demand residual by considering which specific network costs should be socialised.
- Review the triad signal and which costs of the residual, the year round charge and the peak charge are appropriate to recover through a peak demand charge, as triad is now, and which network costs are appropriate to recover through alternative methodologies.

We expect proposed modifications to the treatment of distribution level benefits to be progressed over the coming weeks. We would recommend that Ofgem treat changes in distribution network benefits with similar urgency as transmission network benefits in order to ensure, where possible, they are able to be implemented by the same charging year. Preventing a gap in implementation between the two charging regimes will prevent market instability and help avoid temporary or permanent plant closures.

Response to Open letter

We welcome Ofgem's active interest in understanding the role of network charging in ensuring consumers benefit from a lower-cost electricity network.

Ofgem is right to understand where network costs are not cost-reflective and act, to ensure fair, competitive markets. However, network users impose different costs on the system, and these costs are reflected in both the locational and the residual charge, determined by the arbitrary division between these two charges.

A generator or demand user's position in the electricity market should reflect the costs and charges, including network charges, required to provide or receive their service. It is therefore not inherently wrong that differences in network costs between certain users should lead to competitive advantages in areas such as the Capacity Market.

We would reject Ofgem's comparison of network costs, and the value of avoiding network costs, with Capacity Market auction values and Value of Lost Load estimates¹. These comparisons incorrectly conflate the value of providing energy services with the value of avoiding network costs, which may or may not be of similar value.

Concerns about Ofgem process

The regulator has stated that it intends to approve on the current CUSC modification proposals currently being considered under the CUSC process, CMP264 and CMP265. However, as Ofgem has required these modifications to be placed on an 'accelerated' timetable, the work group has neither sought, nor performed, nor reviewed, any new nor existing analysis on the cost

¹ The calculations in the Ofgem Open Letter appear to overstate the value of embedded benefits on a MWh basis, as a result of underestimating by at least half the number of half hours which generators 'run for triad'; and by incorrectly calculating the value of £72/kW received for delivery in three triad periods.

reflectivity of the embedded benefit. The work group was also not permitted to investigate the costs which are causing the TNUoS demand residual, or to understand how much of the demand residual should be classified as 'sunk costs'.

Ofgem has specifically tasked the work group to deliver its report to the CUSC Panel so the CUSC Panel can reach a decision by 28 November, which is 10 days before the Capacity Market and the latest date a CM participant can choose to exit. We do not think the work group will achieve Ofgem's requirement, as set out in the Open Letter, for "the benefits and costs" to be "properly assessed" and for these "to be considered during the modification process". Ofgem's required timetable has prevented the work group from properly assessing alternative options, requiring analysis of their impacts, or fully understanding the implications of their implementation.

Furthermore, as distributed generators are neither CUSC experts, nor have large regulatory teams, they are at a significant disadvantage, especially on the accelerated timetable required by Ofgem. In September, CUSC work group meetings took up three full days a week, leaving limited staff resources available to improve understanding of the CUSC process or prepare the kind of analysis being provided by better-resourced organisations. The accelerated timetable has successfully prevented smaller organisations from providing the same level of active participation as large organisations.

Limited access to CUSC process and to submit new modifications

Most of the Association for Decentralised Energy's members are not CUSC parties, and there does not appear to be a clear route for companies, who do not have expertise in these processes, to propose CUSC modifications to better address the issues raised in the Open Letter. Ofgem advised work group members that if they wished to make a CUSC modification they could do so by persuading a CUSC panel member to support one, which we do not think represents a workable solution, especially as almost all of the CUSC panel members (SSE, Uniper, ENGIE, Scottish Power and EDF) have proposed alternatives to remove the embedded benefit entirely.

We recognise the independence of CUSC panel members, but it is unfortunate that the CUSC panel does not include any members with specific roles in either the distributed generation or industrial energy sectors, removing important perspective and expertise in the CUSC Panel's discussions and decisions. Such an arrangement, where changes are being proposed and voted on, worth hundreds of millions of pounds, by participants with a specific commercial understanding, should require a much more active role from the independent regulator.

Need to consider issue more holistically

Therefore, it is vital that Ofgem plays an independent, active and analytical role in any review process, rather than relying on individual CUSC modifications. An Ofgem-organised and independently-led review of Embedded Benefits should be integrated with National Grid's project to reform transmission charges to engender a careful, holistic and systematic approach, across both the transmission and distribution networks, and help deliver an enduring solution.

We recommend Ofgem considers any industry proposals for short-term changes, or alterations to individual areas of the overall framework, with care, as there is a risk these could run counter to the conclusions of a holistic review and/or produce unintended consequences in terms of signals to both generation and demand.

Embedded benefits have been in place for 20 years. While longevity is not a reason to keep this charging mechanism, Ofgem would be better placed to look for more evolutionary changes instead of upending a long-standing and deeply embedded arrangement in only six months, with

urgent implementation timescales, and which will likely result in significant unintended results that have not been carefully considered.

It is a result of the stark reduction in TNUoS embedded benefit that is leading to significant interest in grandfathering provisions from a number of market participants. More evolutionary proposals would allow more whole-market approaches and avoiding the need for cliff-edge thresholds between different types of generators.

If Ofgem determines that a 'quick fix' is necessary, we see solutions focussed on rebalancing or redistributing the demand residual as far more likely to deliver cost-effective and deliverable solutions to the issues raised in the Ofgem Open Letter.

We would suggest that Ofgem aim to declare an intended course of action quickly, but ensure the implementation dates of TNUoS changes be 3 years after the Ofgem decision date. This will provide a sufficient lead time for adjusting charging systems on the part of NGET and suppliers. This also allows the new charging structure / methodology to be reflected in customer tariffs at the time of tariff / contract renewal. It is our understanding that suppliers typically contract with customers for up to 3 years.

Risks from CMP264 and CMP265 and the current 'quick fix' approach

We appreciate that Ofgem sees a need to for a 'quick fix' focussed specifically on TNUoS demand residual triad benefit received by distributed generators. However, proposals to move to 'gross charging' for distributed generators, as proposed by CMP264, CMP265, and related alternatives, do not represent either quick or effective solutions.

We also appreciate Ofgem's concerns that a Significant Code Review carries risks of delays in implementing a solution. However, the need to move quickly should not mean Ofgem is obligated to use a solution which creates a range of new problems, especially when other alternatives – such as socialising the value of the demand residual – could more effectively address the growing TNUoS demand residual.

The concept of net charging, and subsequently the embedded benefit, has been a transmission network principle since the 1990s. The proposal to remove this principle and implement an entirely different charging regime in nine months is unrealistic and likely to result in significant harm to generators, suppliers, and consumers. Furthermore, on-site supply of electricity has been recognised within charging arrangements dating back to Secretary of State John Wakeham's decision on the issue in 1991.

The current proposals to charge distributed generators on gross require significant investments in suppliers' IT systems. The scale of these IT changes make it unlikely a move to gross charging can be implemented before 2019, and also make it likely that changes will result in significant cost increases to suppliers and these costs will eventually be borne by consumers.

The TNUoS demand residual is both a charge and a benefit

Energy users on half-hourly meters are currently charged the TNUoS tariff for their use of the transmission network, and these users can avoid this tariff if they do not use the network during these triad periods. In effect, these users receive a triad benefit no different in value, on a per kW basis, than embedded generators.

If Ofgem decides that the triad TNUoS demand residual benefit for avoiding network use is not cost-reflective, then it should follow that charging of the TNUoS demand residual to demand users is also not cost reflective.

We are unsure why Ofgem sees an 'urgent' need to address the consumer impact from an identified non-cost reflective charge on exported distributed generators, but has expressed no urgency to address the impact of a 'non-cost reflective' TNUoS demand residual being applied as a charge on half-hourly metered customers.

The challenges of solving new distortions between different generators, DSR

As Ofgem's open letter has recognised, if the triad benefit is removed for exported distributed generation, there will be an incentive for generators to go 'behind the meter' and avoid the TNUoS demand residual by reducing their net demand during triad periods. However, we are unaware of any methods of charging on-site generation for TNUoS costs which are not highly impractical or undeliverable and no proposed solutions have yet been discussed with stakeholders.

On-site electricity generators and customers are not CUSC parties and are not subject to the CUSC. Instead, it is a customer's supplier which is party to the CUSC. We are unsure if the CUSC has any authority to address on-site generation, connected at the distribution network, as Section 14 of CUSC, paragraph 14.14 states that "*charges should reflect the impact that **Users of the transmission system** at different locations would have on the Transmission Owner's costs.*" [emphasis added]. We would suggest that requiring all on-site generators to be CUSC parties is unlikely to be feasible.

As challenging as addressing on-site generation would be, users who provide 'demand reduction' to receive a triad benefit would likely be even more challenging, and the open letter does not address this kind of user at all; large energy users will still face the triad charge and would still be able to reduce their demand at triad periods to avoid the triad charge. Such an approach would harm Ofgem's flexibility agenda, as DSR aggregators find the recovery of the TNUoS demand residual through the triad charge is harming the demand response market by swamping signals from balancing services.

In the case of both on-site generation and demand reduction, Ofgem would be applying a significant change to large industrial energy users, many of whom are already facing significant energy cost challenges and would likely result in significant loss of jobs on manufacturing sites.

If applying Ofgem's gross charging principles cannot be extended to either on-site generation or demand reduction, the result will be:

- The charge for using the transmission network, as determined by the unchanged triad charge, will be based on a different methodology than that used to determine the value of reducing use on the transmission network.
- The cost of reducing net demand on the transmission network will be different depending on the type of action – exported distributed generation, on-site generation, or demand reduction – taken to reduce net demand.

If Ofgem does not develop and consult with stakeholders on a clear, practical, implementable approach before moving to gross charging for exported generation, Ofgem risks finding itself in a regulatory cul-de-sac, unable to fix new distortions which it had just created and unable to go back to net charging once the overarching issue, the growing TNUoS demand residual, has been addressed. Taking such a regulatory leap into the unknown is unnecessary when more easily implementable solutions, which directly address the TNUoS demand residual, are available.

We would note that if Ofgem feels such an approach is necessary, we would expect Ofgem to estimate the welfare costs associated with the new distortions being created as a result of the

approved modifications, and the costs of the impact from the future modifications, which will be required to address the new distortions.

The issues regarding undue discrimination are addressed in further detail in the attached NERA Report.

Focussing on the growing TNUoS demand residual

Ofgem's primary concern identified in its letter is that the "size and increase of the TNUoS demand residual payments may now be distorting the market". We similarly recognise this issue as a problem which needs to be addressed. However, we are concerned that Ofgem's minded-to approach is actually addressing only a small subset of the problem and by doing so will create new, unsolvable distortions, and require repeated sticking plasters over the coming years.

If the correct focus is on the growing TNUoS demand residual, it would be appropriate to ask why the residual is growing so quickly. The value of the triad benefit has been increasing rapidly in recent years because TNUoS tariffs have increased significantly. The average demand TNUoS tariff has increased from around £12.50/kW in 2005/6 to around £37/kW in 2015/16 and around £45/kW today.

- The biggest driver is an increase in the overall revenues transmission network operators are allowed to collect to cover the increase in its regulatory asset base arising from the current high level of transmission network expansion.
- In recent years, the proportion of this overall revenue which is recovered from demand has increased, owing to an EU cap on the level of transmission charges which can be levied directly on generation.
- At the same time, final consumption of electricity has fallen by around 13% from 2005/6. Increased embedded generation has exacerbated this effect – triad demand and overall transmission network demand have both fallen by around 18% over this period.

How to directly tackle the impact of the growing demand residual

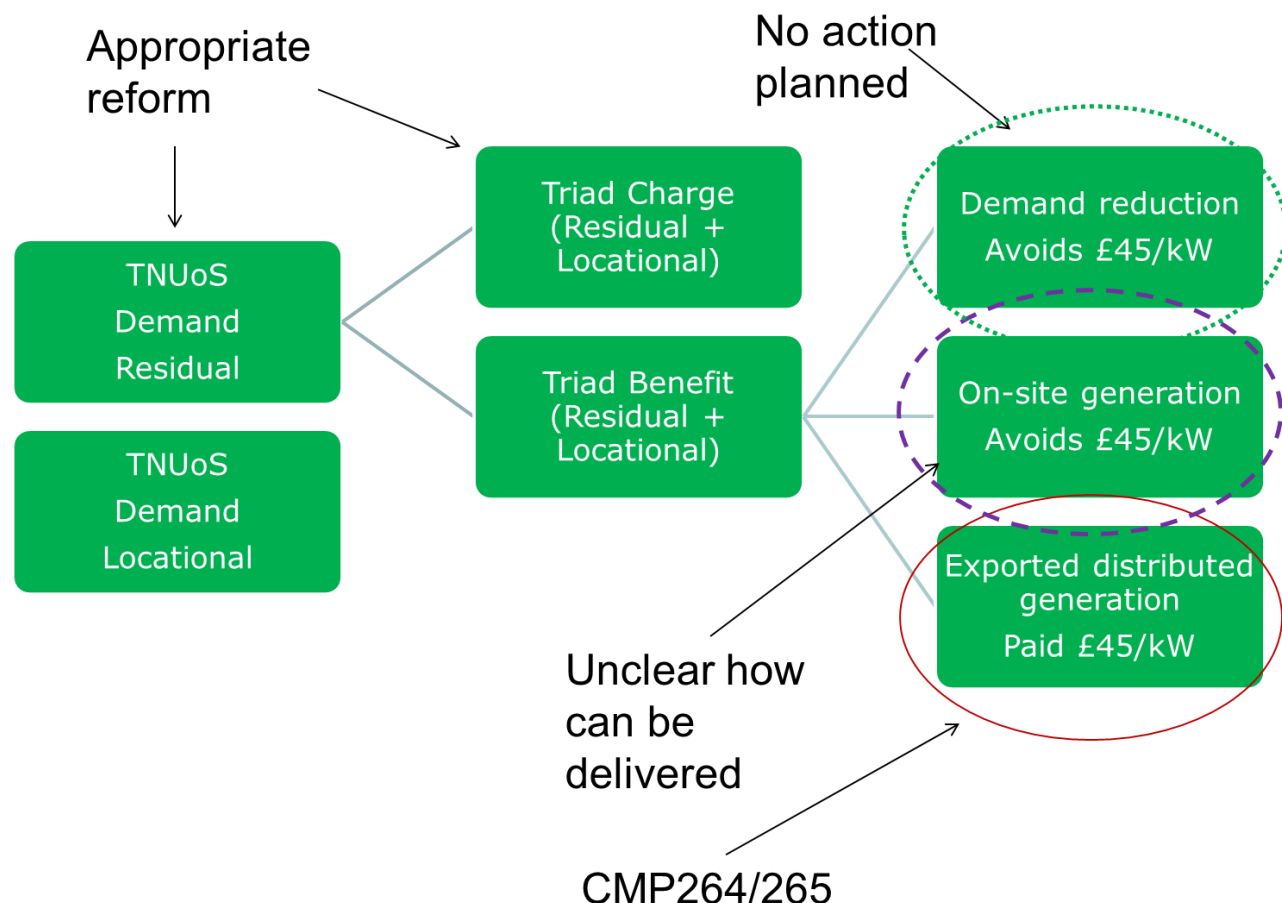
By implementing changes only to the triad benefit, and even then only the triad benefit received by exporting distributed generators, Ofgem will not be directly addressing its identified non-cost reflective charge. It would be more appropriate for Ofgem to address the level of the triad charge caused by the fast-rising demand residual, rather than the benefit received by distributed generators. We believe three steps would help address the fast-growing demand residual:

- Reduce the demand residual by reviewing the size of the money recovered from the locational charge, which is currently limited to just 10% of the overall costs of the network.
- Reduce the demand residual by considering which specific network costs should be socialised.
- Review the triad signal and which costs of the residual, the year round charge and the peak charge are appropriate to recover through a peak demand charge, as triad is now, and which network costs are appropriate to recover through alternative methodologies.

We discuss these solutions in further detail further in this response, as well as potential stopgap options which could be implemented more quickly pending a more formal review on these issues.

However, Ofgem states that they see in CMP264 and CMP265, and related alternatives, a way to address the issues they have identified in their open letter. However, these modifications do not provide appropriate solutions, as they have narrowly defined their identified defect to the triad benefit received by distributed generators.

CMP264 and CMP265's narrow definition of the defect has prevented the work group from raising alternatives which address the TNUoS demand residual and result in a more appropriate solution to the identified problem. Either alternative industry CUSC modifications will need to be proposed to more directly address the TNUoS demand residual or Ofgem will be required to step in with its own review, if the actual relevant issue of the TNUoS demand residual is to be directly addressed.



Relationship between TNUoS demand locational and TNUoS demand residual

The TNUoS demand residual is not, as the Ofgem letter states, "largely fixed and sunk costs". The residual is a cost recovery mechanism, required because there are costs accrued on the network which have not been allocated to specific users. For example, offshore transmission generators pay a portion of the costs they drive onto the transmission network, and the rest of these costs are then socialised onto demand users through the demand residual.

Therefore the cost reduction benefits of distributed generators, through the reduction of net demand, are reflected in both the residual and the locational elements of the TNUoS charge.

We do not agree that "the connection of an increasing amount of sub-100MW EG to the distribution system logically cannot help to avoid sunk/fixed costs of developing and maintaining the transmission network", as Ofgem states in its letter. Reduction in network demand leads to reduced asset requirements over time. Logically, if the transmission network demand continues to fall over time, long-run transmission network costs would fall as network infrastructure is not replaced.

Ofgem's Open Letter similarly argues that the locational charge is a 'cost reflective' element in the TNUoS charging methodology, while the residual is not. As outlined in the response from NERA (see attached), this assumption is false.

"The locational element of D-TNUoS charges is only "cost-reflective" in the sense that it emerges from a load flow modelling exercise that seeks to estimate the degree to which the costs imposed on the system by users in different parts of the country varies. Hence, the locational charge seeks to reflect only the degree of variation in charges across the country.

"The level of the locational charge – and by implication the level of the demand residual charge – is in no sense cost-reflective. In fact, it depends on arbitrary regulatory decisions on the G:D split (currently determined by EU regulations) and on the choice of the reference node within the load flow model...

... "The key implication of this discussion is that any attempt to address the purported distortion by adjusting the residual charge alone ... would represent an entirely arbitrary change to the current D-TNUoS methodology, because the split between the residual and locational charge is itself arbitrary."²

In addition to arbitrary decisions such as the reference node and the G/D split, there is also evidence that the level of cost recovery from the locational charge is significantly undervalued on a cost-reflective basis, both reflected in Imperial University's long-run marginal cost modelling, and as a result of the choice of an expansion constant value.

Analysis in the attached report from Imperial University shows how alternative and arguably more cost-reflective approaches on setting the locational charge could result in a larger amount of revenue recovery from the locational charge and a smaller demand residual. Imperial University have identified that onshore transmission expansion costs are currently assumed to be £60/MW/km, and £160/MW/km/yr for bootstrap investments. However, there is strong evidence that the marginal cost of expanding the onshore network should be three-fold higher at £180/MW/km/yr.

While currently less than 10% of total revenues are collected through the locational element of the charge, with changes outlined in the Imperial report, there is a material increase in the revenue collected through the locational element of the charge to around 60% of the total in 2016/17. These findings show both how the size of the residual is relatively arbitrary and linked to other policy decisions, and therefore distributed generators, by reducing demand on transmission networks, could be seen to have an impact on the costs larger than that captured within the locational charge.

These issues are addressed in more detail, including detailed modelling results, in the attached report from NERA and Imperial University.

Socialising specific network costs

The growing TNUoS demand residual, set against a falling transmission network user base, may indicate a need to consider whether certain residual costs should be socialised, rather than allowed to accrue to specific sub-sets of users, as currently occurs within the demand residual.

We recognise that it may be beneficial to 'socialise' certain network costs which are relatively fixed, or are to deliver national benefits, such as offshore renewables. However, as noted it is incorrect to describe the demand residual as 'sunk' costs. Instead it is required to identify specific costs. Such efforts to 'socialise' specific costs could look at areas such as:

- Offshore transmission costs, driven to deliver specific policy objectives for offshore wind, and the cause of most of the demand residual growth in coming years.

² NERA, 2016. *Review of Ofgem's Open Letter on Charging Arrangements for Embedded Generation*.

- National Grid administration and innovation costs, which could be considered unrelated to infrastructure costs
- Stranded transmission assets
- Allocating portions of costs to customers who want to maintain access to electricity networks but do not use them and therefore do not pay use of system charges.

By reaching a policy decision to socialise certain network costs, Ofgem would reduce the impact of the demand residual on both demand users and distributed generators, delivering a more systematic and holistic approach.

Charges recovered through the triad mechanism and impact on dispatch

We recognise Ofgem's concern that the TNUoS demand residual triad benefit is "distorting dispatch by dampening prices at peak times when EG dispatch out of merit to generate in the triad periods". Ofgem has also noted that distributed generators respond to a triad signal, and that this signal is unavailable to transmission connected generators "and hence is a distortion".

If Ofgem believes all generators should face similar charging mechanisms, then we would suggest it would be more appropriate to reform the triad mechanism itself, such as considering whether it is appropriate to spread part or all of the current triad charge, such as the residual or the year round charge, over a different charging window or through a different mechanism.

However, Ofgem's interest in creating the same charging methodology for distribution and transmission generation ignores the fact that distributed generators are not transmission network users. Instead, Ofgem should ensure that any changes to charging mechanisms apply a single approach to both demand users and distributed generators, as these two types of users have the same impact on the transmission system. Setting different triad charging windows for generation and demand will create new distortions and create significant administrative difficulties for suppliers.

We would also note that any changes to the triad mechanism methodology should be based on clear evidence reflecting the impacts of different network use on network costs. We would note that while there are alternatives proposed to CMP264 and CMP265 which would change the triad charging window, the work group considered no evidence on the impact of different approaches and whether particular methods were more cost reflective than another.

The need to align TNUoS changes to distribution network changes

Ofgem has acknowledged in its open letter that distributed generators face different connection charging regimes, "but that DUoS charges do not significantly disadvantage EG" as "DUoS charges give embedded generation a credit for offsetting investment between them and the GSP". This analysis fails to recognise the significant competitive advantage created by the different connection arrangements between transmission and distribution networks, where distribution-connected generators must pay for all of the relevant reinforcement costs up front.

Furthermore, there is evidence that distributed generators are currently being under-rewarded in distribution charging for the benefits they provide to the distribution networks. Cornwall Energy has undertaken analysis and found that distributed generators are under-rewarded by £7 to £16/kW.³ There are a number of key areas where we see distributed generation being under-rewarded, and we have outlined them in the Annex below.

³ Cornwall Energy, 2016. A Review of the Embedded Benefits accruing to Distribution Connected Generation in GB.

We are aware of DCUSA modifications being proposed in the coming weeks which we hope will reach Ofgem in time to be implemented in April 2019. However, as Ofgem has placed CMP264 and CMP265 on an 'accelerated' timescale, there is a risk that distributed generators will see a significant revenue reduction before changes in distribution charging can take effect.

Any gap could have a significant revenue impact for a number of generators, creating market instability and may result in temporary or permanent plant closures. We would therefore recommend that Ofgem treat changes in distribution network benefits with similar urgency as transmission network benefits in order to ensure, where possible, they are able to be implemented by the same charging year.

Balancing Services Use of System charges

We look forward to understanding Ofgem's further thinking on how it would be appropriate to differently distribute Balancing Services Use of System charges to distributed generators. As Ofgem considers this issue, however, it will be important that Ofgem considers both the costs applied to different users, as well as the different benefits received by different types of generators.

We would note as well that transmission-connected generators have commercial relationships with National Grid, which distributed generators do not.

We expect there may be benefits received by transmission generators through BSUoS which will need to be considered as part of any reforms. We would also note that any proposals should consider the different types of distributed generators and their different impacts on balancing costs, as intermittent distributed generators will have much different cost impacts than non-intermittent generators.

Market impacts from the removal of embedded benefits

Industrial manufacturing

Combined heat and power (CHP) provides heat and power to customers across a range of manufacturing sites, as well as commercial and public sector organisations, including through district heating networks. CHP can include all range of fuels, including natural gas and renewable fuels such as biomass and biogas. About 8% of CHP capacity uses renewable fuels, although this share is growing quickly. Whatever the fuel used, by capturing its heat, CHP provides the most efficient use of that fuel.

CHP capacity in the UK is approximately 9 GW of capacity, with about 6 GW of that electrical capacity classified as 'Good Quality' capacity. Of the 9 GW in total capacity, we estimate that more than 4 GW is connected on distribution networks. Approximately 90% of CHP capacity, or 375 sites, are based in industrial manufacturing sectors, including refining, chemicals, paper, food and drink, and steel.

The amount of electricity which CHP sites export can vary significantly from site to site, from no export to more than 80% of power exported. The removal of the TNUoS demand residual embedded benefit from on-site and exported CHP capacity would result in approximately £200m in increased energy costs across these businesses, increasing energy costs significantly during an uncertain market period. Some specific industrial sites in the paper, chemicals and food and drink sectors would see energy cost increases of up to 19%, or £5m a year.

Current low wholesale electricity market prices are quite challenging for existing gas CHP generators, meaning the removal of the embedded benefit could result in the shutdown not just of their CHP assets, but of the sites themselves. Larger, older industrial CHP sites run as baseload generators, delivering a steady heat supply for industrial processes and exporting electricity during both peak and non-peak periods.

One large chemical manufacturer have said they are likely shut down their 100 MW CHP site if the triad embedded benefit is removed, putting 1,500 manufacturing jobs at risk. We would expect other large, industrial distribution-connected CHP generators risk shutting down, increasing net demand on the transmission network and risking security of supply.

Wider distribution sector

Other distribution technologies would be similarly impacted by the proposed change, including non-intermittent and intermittent renewable technologies. For example, we are aware of a 10 MW community wind project which will fail to meet its debt payments as a result of changes to the embedded benefit. Electricity storage projects will also be significantly impacted by changes in this area, and there is evidence a number of bidders in the recent Enhanced Frequency Reserve tender for storage require embedded benefits to deliver.

Security of supply

As Ofgem is aware, National Grid estimates there is 7.5 GW of distributed generation which operates at peak, and there is a risk that these generators will be less responsive to other market signals during peak periods. Legacy, large-scale industrial CHP plant are largely operated as baseload generators, but are able to reduce on-site demand and have some flexibility to increase generation during system peak. As these operators are industrial manufacturers with limited engagement in the electricity market, they often struggle to respond directly to market signals and are likely to operate less flexibly during periods of peak demand if the triad charge is removed.

Even a reduction of 15% of supply at peak periods would result in a 1 GW shortfall in coming winters, during a period of significantly tight security of supply margins. Reports by both Cornwall Energy and KPMG have highlighted that approximately 2 GW of existing distributed generation has received Capacity Market contracts. The removal of the embedded benefit could result in those plant under construction not being completed and existing plant shutting down, resulting in further capacity shortfalls in 2018 and 2019.

In its report for the ADE, Cornwall Energy estimated that the removal of embedded benefits would result in an increase in Capacity Market costs to consumers of at least £282m, not including the increased balancing services costs for National Grid to manage peak demand periods. Cornwall Energy has also noted that due to larger Capacity Market procurement this year, the increased consumer costs would likely be higher than the estimates in its report, balancing against any consumer savings from embedded benefit reductions.

For further information please contact:

Jonathan Graham, Head of Policy
Tel: +44 (0) 20 3031 8740
Jonathan.graham@theade.co.uk

Annex

The ADE has identified the following areas as examples of where distributed generators are not being sufficiently recognised for the benefits they provide to distribution networks. The ADE is

aware that DCUSA parties will be making modification proposals related to some of the issues outlined below.

Credits at the voltage of connection. Embedded generators who connect directly at LVS do not currently get a credit for avoiding the use of the LV substation. However, the principle that the benefit is realised at the substation where the capacity can be reduced holds true even though the generator is connected directly to a LVS and it is therefore appropriate that LVS generators should receive the benefit at the voltage of connection.

Customer contributions. Within the CDCM, demand charges are reduced by the customer contribution to take account of the amount paid up front when a customer connected, to avoid double charging. When a generator connects to the network, one of the benefits that is realised by the DNO is a reduced flow on the local network. This allows further demand customers to connect without the need for reinforcement and therefore they will need to make less of a customer contribution when they connect. Consequently, applying the customer contributions to generation credits reduces some of the benefit that embedded generation brings to the network operator. Therefore, the level of customer contributions that is taken into account for generation customers in the calculation of DUoS credit should be removed.

Scaling. A proposal related to scaling, DCP 228, has recently been approved by Ofgem, considering the costs recovered from scaling and classifies these as primarily recovering the replacement of existing assets. These costs are not considered as avoidable and are therefore excluded from the derivation of the incremental cost within the model and thereafter recovered from scaling. However, distributed generation does not just defer future reinforcement, it also potentially enables existing assets to be replaced by smaller, less costly assets when they reach the end of their life, and should be recognised under the scaling arrangements.

Transmission exit charges. Transmission exit charges recover the capital cost of GSPs on behalf of transmission companies from DNOs. Distributed generation offsets demand at the GSP level and therefore reduces the need for future reinforcement at the GSP. This principle is accepted within the CDCM where generation receive a credit for offsetting transmission exit charges. In the EDCM, an award for Transmission exit credits is only paid to qualifying generators that have an agreement with the DNO, the terms of which require the generator, for the purposes of P2/6 compliance, to export power during supergrid transformer (SGT) outage conditions. As most EHV generators do not have this agreement, very few generators receive a credit in this respect.

Direct and Indirect operating costs and network rates. Within the CDCM, distributed generators receive a credit for reducing direct operating costs at voltage levels above the level of connection. This is because they reduce the demand and therefore the level of infrastructure required at higher voltage levels. This results in less reinforcement and also a saving in direct and to a certain extent indirect costs. Distributed generation benefits DNOs by reducing the expenditure on network rates, direct and indirect operating costs. The principle adopted within the CDCM should be examined to determine whether it is appropriate at EHV level by rewarding distributed generation at voltage levels above the level of connection.

Exporting distributed generators do not always receive DUoS credits. Some distribution networks use the FCP methodology, which will not give a credit for exporting generators. In some cases, the FCP methodology may use a forecast of load to see if reinforcement is needed, and if the generator is exporting, the methodology determines there is no need for reinforcement and therefore no credit.