



Bringing Energy
Together

Response to CMP264/265 consultation 18 April 2017

Context

The ADE is the voice for a cost effective, efficient, low carbon, user-led energy system. With over 100 members we bring together interested parties from across the sector to develop a strong, dynamic and sustainable environment for a range of technologies including combined heat and power, district heating networks and demand side energy services, including demand response and storage.

The ADE welcomes the opportunity to respond to Ofgem's consultation and draft Impact Assessment on CUSC modification proposals CMP 264 and CMP 265.

Summary

The ADE does not agree with Ofgem's minded to position to implement WACM 4 under the CMP264/265 modification proposals.

We do not believe:

- That sufficient evidence or analysis has shown what level distributed generators, in aggregate, are over rewarded through TDR payments.
- That any evidence has been provided that the locational is cost-reflective in absolute terms and therefore whether it fairly reflects the value net demand reduction brings to the transmission system.
- That WACM 4 reflects the different treatment, and therefore the different investment requirements, of <100MW embedded generation compared to transmission connected generation, as required under the SQSS.
- That benefits of distributed generators on reducing consumer costs, including avoided GSP costs, avoided NGET revenue recovery, and avoided generation residual have been recognised in Ofgem's analysis.
- That sufficient evidence or analysis has shown consumers will be better off as a result of these changes.

We agree that there is a problem arising from the fast-growing residual. However, this code modification does not consider these issues holistically or systematically, and attempts to change a symptom (TDR payments to distributed generators) instead of the disease (the fast-rising residual).

We would recommend Ofgem instead implement WACM 7, which would significantly reduce the TDR payment until further reviews, including the Targeted Charging Review, can be completed.

WACM 7 would deliver:

- A TDR payment of approximately £17/kW, which would most closely reflect the existing evidence of the network benefits received by distributed generators compared to transmission connected generators, including:
 - Current estimates of avoided GSP costs (£2/kW)
 - Estimate of additional avoided GSP costs from Super Grid Transformers (up to £5.45/kW)
 - The avoided cost of the generation residual caused by transmission generation being displaced by distributed generation (displacing a £7/kW payment to transmission generators, and a £15/kW cost to consumers)
 - The avoided increase in National Grid's allowed revenue, and therefore the consumer savings, resulting from avoiding new transmission-connected plant (~£5/kW)
- Continued locational signals for distributed generators between zones.
- Protection for investors and cost of capital, delivering significant benefits for existing consumers.
- A recognition by Ofgem that there are significant areas of inquiry needed over the next 18-24 months, allowing them to complete these reviews and consider next steps, and preventing unnecessary financial risk to existing generators, investors and industrial sites.

By implementing WACM 7, Ofgem would be ensuring it does not implement changes now which need to be reversed as part of its Targeted Charging Review process. Ofgem's Targeted Charging Review, and potential Significant Code Review, will be considering many of the issues addressed in CMP 264/265, including what proportion of "transmission residual charges should be charged to generators (transmission- or distribution-connected), storage (transmission- or distribution-connected), and demand". WACM 4, however, has made an immediate decision that the TDR value should be £2/kW, and could potentially be reversed following the TCR.

Ofgem specifically noted in its CMP 227 decision letter that "It is not clear what the outcome of this work will be and it is possible that it will not be consistent with [this change proposal]. This could mean that legislation is implemented at the EU level that supersedes [this change proposal]. In our view, this would increase regulatory risk and, ultimately, costs to consumers." We believe the same assessment would apply to CMP 264/265.

If, however, Ofgem moves forward with WACM 4 as indicated in its minded-to position, the use of a 3-year phase-in is very welcome, and provides Ofgem with an opportunity to both measure the impact of its changes after each year's reduction and to better understand the key issues before the final and most harmful TDR reduction in 2020-2021.

If WACM 4 is implemented, we would recommend Ofgem implement a clear, transparent process to:

- Review how the 2018-19 reduction and 2019-2020 reductions in the TDR impact the electricity market, including the Capacity Market, wholesale prices, and balancing costs. By setting out that review process in a forward-looking and transparent manner, Ofgem can provide confidence to market participants and ensure each reduction of the TDR is delivering the expected market benefits.

- Ensure the Targeted Charging Review and Future Focussed Strategy address specific areas of competitive or non-cost-reflective distortions which harm distributed generators and demand response providers, including the impact of distributed generators and demand reduction on:
 - The cost of the generation residual
 - The avoidance of the RIIO incentive's Load-Related capex
 - Long-run transmission network costs
 - Avoided GSP costs

The CMP 264/265 process and future reviews

We believe Ofgem's review related to CMP 264/265 has been rushed and therefore lacks robustness. While Ofgem has been reviewing the embedded benefit since the start of 2016, it has done so through bilateral meetings, and has provided no opportunities for necessary detailed industry discussions. These issues are highly technical and highly complicated, with clear financial interest on either side of the debate, and are poorly suited to short, bilateral meetings instead of all-day work groups.

Since the start of its review, Ofgem has focussed entirely on where distributed generators are potentially over-rewarded, but has not indicated any interest in areas where industry has raised concerns distributed generators are under-rewarded, including distribution network connection charges, specific elements of the CDCM and EDCM, and avoided GSP costs.

The CMP 264/265 process should have provided an opportunity for more a robust industry-led review, but it was narrowly defined by the proposers to focus just on how the residual impacts distributed generators, rather than at the causes of the residual and its impact on the wider marketplace. The CMP 264/265 process was also placed on an 'accelerated' timetable by Ofgem, and the working group was consistently denied opportunities to understand issues in more depth or undertake analysis. For example, no time was spent investigating the drivers of the Transmission Operator's revenues. Ofgem requested from the work group a wide range of alternatives, receiving several dozen proposals, but through the implementation of strict timetables, did not allow the working group to explore, understand, test and assess those alternatives in any depth. As such the CMP 264/265 process provides insufficient rigour on which to base any decision.

The current consultation on CMP 264/265 is welcome, but has provided limited opportunities to meaningfully review Ofgem's proposals, considerations and quantitative assessments, falling short of Ofgem's own guidance for 3-month consultations for changes with significant impact. As Ofgem is aware, small generators and market participants have significantly less resource than large generators, in addition to significantly less expertise in the CUSC and related areas. The 'accelerated' timescales for CMP 264 and CMP 265, in addition to this rushed consultation processes, have only exacerbated this unfairness.

Responses to Questions

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

No.

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.

As we set out in our response, we do not believe:

- That sufficient evidence or analysis has shown what level distributed generators, in aggregate, are over rewarded through TDR payments.
- That any evidence has been provided that the locational is cost-reflective in absolute terms and therefore whether it fairly reflects the value net demand reduction brings to the transmission system.
- That WACM 4 reflects the different treatment, and therefore the different investment requirements, of <100MW embedded generation compared to transmission connected generation, as required under the SQSS.
- That benefits of distributed generators on reducing consumer costs, including avoided GSP costs, avoided NGET revenue recovery, and avoided generation residual have been recognised in Ofgem's analysis.
- That sufficient evidence or analysis has shown consumers will be better off as a result of these changes.

We agree that there is a problem arising from the fast-growing residual. However, this code modification does not consider these issues holistically or systematically, and attempts to change a symptom – TDR payments to distributed generators – instead of the disease.

By properly allocating costs to those parties that cause them would result in a reduction of the residual charge. A high residual payment is a symptom of poor allocation of costs, it is not the problem in its own right.

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

We agree that fast-rising demand residual need to be addressed. However, we believe demand residuals need to be addressed as they apply to the electricity system as a whole, rather than just how they apply to distributed generators.

Furthermore, we see it as insufficient for Ofgem to urgently address how rising residual charges and payments are charged or avoided without addressing *the cause of* rising residual payments.

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

Yes.

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

No. We have provided our evidence in response to Question 5.

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

We do not agree with Ofgem's assessment of the CUSC Objectives, and have addressed them individually below.

CUSC Objective A**The level of TDR Payments**

Ofgem's assessment under Objective A relies on the assumption that TDR payments above £2/kW to distributed generators are anti-competitive. This assumption is based on insufficient evidence.

We address this issue in further detail under our response to Ofgem's assessment of CUSC Objective B. However, for avoidance of doubt, we set out briefly here the values delivered by distributed generation and demand reduction above Ofgem's proposed £2/kW figure:

- i. Sub 100 MW embedded generation is treated differently by the SQSS to larger transmission generation and therefore imposes different investment costs on the system.
- ii. A reduction in the level of transmission connected generation and therefore a saving from avoiding the negative generation residual.
- iii. The avoided increase in National Grid's allowed revenue, and therefore the consumer savings, resulting from avoiding new transmission-connected plant.
- iv. The avoided cost of GSPs, including Super Grid Transformers.
- v. The amount of benefit some users provide to the transmission network above the signal provided by the locational charge, which is not a cost-reflective recovery of the costs demand users impose on the transmission system.

Further details on these points are addressed under CUSC Objective B.

Options including the TNUoS generation residual

Generation residuals are expected to go negative by 2017/18 and fall to -£671m by 2021¹. Ofgem has rejected the option to pay distributed generators the value of the generation residual. Ofgem states this decision is due to its concerns that a positive generation residual will not be recoverable from distributed generators due to Ofgem's preferred flooring option.

However, Ofgem's logic on not paying the generation residual could just as easily be applied to the demand residual, which is expected to continue to rise, but could also theoretically fall. Ofgem has assumed the demand residual trajectory is set, while the generation residual trajectory is unknown. We think this logic is flawed and unfair between different generation types. We see no logic for Ofgem to reject the distortive impact of generation residuals on competition.

Similarly, Ofgem's minded-to flooring position states it is acceptable to not recover the negative locational charge from distributed generators. However, Ofgem thinks it is unacceptable for a positive generation residual to not be recovered. Again, these two positions appear contradictory and therefore flawed.

The impact of the generation residual is material. Assuming 7.5 GW of embedded generation operating at triad, the avoided demand residual payment to distributed generators would be £525 million in 2021, a lower cost to consumers than the negative generation residual of -£671m.

¹ National Grid industry consultation for CMP264/265. August, 2016.

The generation residual has an impact on competition, providing a £8.6/kW benefit to 78 GW of transmission generation by 2021². However, it has an even larger impact on consumers, as it is funded from the 45 GW of demand through the demand residual, costing demand users £15/kW³.

Ofgem's Impact Assessment states that removing the TDR will result in transmission generation replacing distributed generation in the Capacity Market. With a negative generation residual, every megawatt of displaced transmission generation avoids an additional £8.6/kW payment to transmission generators, which also avoids an additional £15/kW charge to demand customers.

Therefore, Ofgem's assessment that both 'With TGR' and 'without TGR' is neutral under Objective A is flawed. To both ensure fair competition and to reduce cost to consumers, it is entirely appropriate to pay distributed generators the equivalent of the generation residual.

Under Ofgem's modelling of Scenario 3, included in its Impact Assessment, there will be an additional 8 GW of transmission-connected generation. Assuming no change in the generation residual from 2021, consumers will face a total aggregate net increase in cost of £714m by 2034 (without discount rate) under Scenario 3 versus the Status Quo⁴.

The continuation of the generation residual, when considering the cost on the total transmission generation fleet as of 94 GW assumed under Scenario 3, would have an undiscounted, aggregate cost to consumers of £10 billion up to 2034⁵.

Options to prevent disincentives for smaller generators to generate at peak periods

We disagree with the assessment on how to address negative locational triad signals.

Ofgem has rated both flooring options at 'neutral', when the application of the lowest locational protects the locational signal across Great Britain. Under Ofgem's accepted flooring at zero methodology there will be no locational signal for distributed generation between approximately half of the UK's 14 demand regions.

The locational signal for distributed generators is important. A large number of distributed generation types do not have the option to connect to the transmission system. For example, a CHP plant is sized to meet its customer's heat demand. A 10 MW CHP plant sized for a specific user's site will not be able to connect to the transmission network. Therefore, it is arguably just as important for smaller plant see cost-reflective charging signals across different distributed generators as to see cost-reflective charging signals between distribution and transmission networks.

Ofgem notes in its consultation that any payment above the estimated avoided GSP value of £2/kW cannot be justified. However, this response has highlighted that distributed generators are currently providing, and will in future provide, significant value above £2/kW. Therefore, by implementing WACM 7, Ofgem will be delivering:

- A residual payment that is more beneficial to competition
- A residual payment that protects the locational signal for distributed generators.

² £671m divided by 78 GW of generation. 78 GW of generation is the total generation assumption in Ofgem's CMP264/265 Impact Assessment.

³ £671m divided by 45 GW of demand.

⁴ £7/kW charged annually in each year up to 2034 for each kW of transmission generation which would not have occurred under the Status Quo, estimated in the Impact Assessment's Scenario 3 modelling.

⁵ £7/kW charged annually in each year up to 2034 for each kW of transmission generation, including both existing and new, estimated in the Impact Assessment's Scenario 3 modelling.

Impact of demand connection charges on competition

Ofgem has given no consideration as to whether the 'super steep' connection charges faced by distributed generators distort competition between transmission and distribution connected generation.

A distributed generator faces both a steep connection cost and distribution and transmission usage charges and credits. This connection cost is not faced by transmission-connected generation, who are able to connect to the electricity system using 'super shallow' charges.

New evidence by Cornwall Energy as part of its response to this consultation has found that average distribution network connection costs are between £61/kW and £173/kW, in comparison with transmission generation connection costs of £12/kW, equating to a competitive difference of between £49/kW and £161/kW.

When a distributed generator imposes costs on the transmission system, the Statement of Works process determines that distributed generators can only connect to the distribution system if the existing transmission system is able to manage the changes in flows to/from the transmission system. This ensures that distributed generation can only connect when there is spare capacity on the transmission system or their generation can be accommodated with zero incremental cost. Unlike transmission generation connections, which are super shallow, there is no TNUoS cost increase. There are also no increases in RIIO allowance.

All users must, by definition, connect to the GB electricity network. If certain users pay more in connection costs, than the assumption is they would pay less from usage costs. However, under the current system transmission generators' connection costs to both the transmission network and the distribution network are socialised, unlike distributed generators. Under WACM 4, distributed generators would receive no recognition for these higher costs through their TNUoS usage charges and benefits.

Impact on competition between suppliers

Ofgem's minded-to decision is discriminatory on different electricity suppliers. We have set out below the case of two electricity suppliers connecting to the same GSP point as follows:

	Supplier A	Supplier B
Gross demand at ACS peak	20 MW	60 MW
Embedded generation	-	40 MW
SQSS impact	20 MW	20MW

According to the SQSS' methodology, both suppliers' portfolios will have the same impact on the transmission system. However, under WACM 4, Supplier A will receive triad charge on 20 MW of demand, while Supplier B will receive a triad charge on 60 MW of demand.

Therefore, different suppliers portfolios will face different charges, despite both having identical impacts on the transmission network as determined by the SQSS. This outcome will create unfair competitive distortions between electricity suppliers.

Objective B Cost reflectivity

Value of the payments to smaller EG

We believe Ofgem's assessment that distributed generators should not receive payments above £2/kW for the benefit they provide to the transmission system incorrect for four reasons:

- **The locational charge.** The amount of benefit some users provide to the transmission network above the signal provided by the locational charge, which is not a cost-reflective recovery of the costs demand users impose on the transmission system
- **The SQSS' treatment of distributed generation.** Sub 100 MW embedded generation is treated differently by the SQSS to larger transmission generation and therefore imposes different investment costs on the system.
- **The impact of distributed generation on allowed revenue recovery.** The avoided increase in National Grid's allowed revenue, and therefore the consumer savings, resulting from avoiding new transmission-connected plant.
- **Avoided Generation residual.** A reduction in the level of transmission connected generation and therefore a saving from avoiding the negative generation residual.
- **Estimate of avoided GSP costs.** The assumed estimate of avoided GSP cost is based on insufficient data and does not include the cost of Super Grid Transformers.

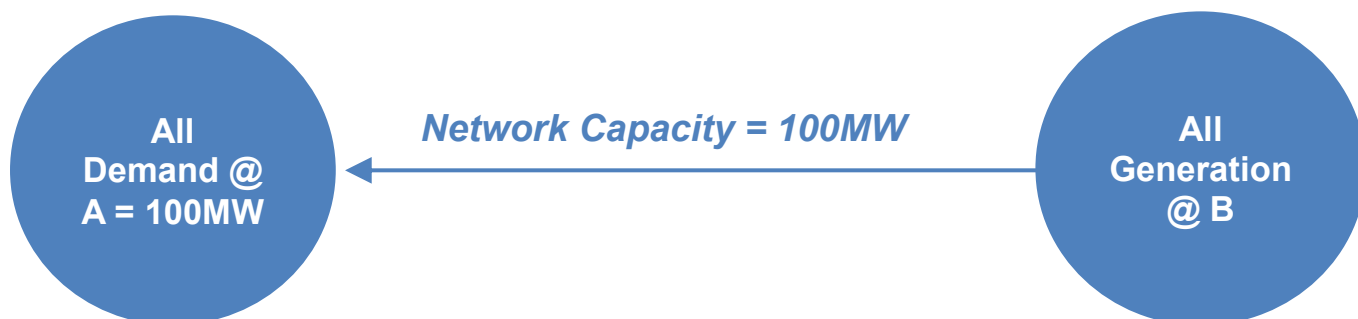
We have addressed these elements in further detail below.

The demand locational is not 'cost reflective'

The locational charge alone does reflect the cost or benefit to the transmission network caused by users. Rather, the locational charge sends a cost-reflective signal on the variation in costs imposed by users in different locations. The locational charge arguably cost-reflectively signals the relative costs of transmission in different locations, but it was never designed to signal the absolute level of the costs imposed or avoided.

Analysis by NERA, previously submitted to Ofgem, shows how generation is not fully recognised for the locational benefits it provides.

In the example of a two-node system, where all electricity demand is located at a single node (A), and this node is connected to a second node at which all generation is connected to the system (B). In this system, marginal increases in peak demand would marginally increase the need for transmission to move power from B to A, and the installation of generation to serve peak demand locally at node A would reduce the need for transmission.



However, in this case, the ICRP methodology would set a locational charge for demand at node A equal to zero, because node A would be the reference node and locational charges are zero at the reference node. As such, generation would receive no signal regarding the value they bring to the system in terms of peak demand reduction if they only face the locational element of the charge.

This point can be proven in the UK network system by considering the total amount of costs which are recovered from the locational demand charge. No matter where on the system demand is located, the total amount of revenue the demand locational charge will recover is near zero. For example, if all demand was to be suddenly located in London, despite creating significant new locational costs on the network, the total amount of revenue recovered from the charge would remain largely unchanged.

In contrast with the locational element, the demand residual charge moves with the rise and fall of the costs of the transmission system. Therefore the residual, unlike the locational, responds to changes in the overall cost of the transmission system. However, we recognise that the residual costs are not necessarily allocated to the correct parties causing the change other than via the modulation of the locational charge.

Further evidence on the lack of cost-reflectivity in the locational charge has been provided to Ofgem by Imperial College. Imperial College used its Dynamic Transmission Investment Model (DTIM) to estimate the amount of revenue that would be recovered through locational TNUoS charges linked to the Long Run Marginal Cost (LRMC).

Through this modelling exercise, Imperial estimated the revenue that would be recovered through the locational element of the charge if it were set to better reflect the LRMC of transmission. The current transmission network expansion constant is based on a 400kv OHL, the cheapest transmission asset to construct, and up to three times lower than recent transmission network investment costs.

A different expansion constant based on actual transmission system built would lead to a different and arguably more cost-reflective locational cost. Imperial's modelling showed tripling the expansion constant would materially increase the amount of revenue collected through locational charges from around 10% to around 60% of the total revenue recovered through "wider" TNUoS charges, and thus reduce the amount that needs to be collected through the residual.

This evidence shows clearly that the locational charge is not cost reflective, and therefore is not a fair representation of the value or costs which users bring to the transmission system. Ofgem's assumption under Objective B is therefore flawed.

There is no analysis of whether WACM 4 delivers a more cost reflective charging regime

We accept that the TDR is recovered in a non-cost reflective manner. However, Ofgem has made no consideration whether its removal would reduce the cost-reflective charge as applied to specific generators or distributed generators on the whole.

Unlike the locational charge, the residual charge rises or falls in response to the overall costs of the transmission network, and therefore has a role as a cost-reflective signal to network users. However, as is recognised by Ofgem, the residual charge is not allocated to specific parties who drive those costs.

The evidence outlined above notes that the locational charge is likely under-rewarding or under-charging users for their benefits or costs to the networks. Ofgem has not made any consideration whether distributed generators, on aggregate, are over- or under-rewarded. If distributed generators were being fairly or under-rewarded on aggregate, Ofgem's proposed action would reduce net cost reflectivity.

Conflict in how demand and distributed generation treated under the SQSS

Both the calculations used to set TNUoS charges and the philosophy behind the ICRP methodology are linked to the planning standard that defines the transmission investments that

the Transmission Owners are obliged to make to accommodate different types of users in different locations. This standard is known as the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS).

Among other things, the SQSS defines how much transmission has to be built to accommodate changes in the mix of generation technologies, the volume or location of generation capacity, and changes in the level or regional dispersion of peak demand. It does this by requiring that the Transmission Owners build sufficient capacity to meet two planning criteria, which, taken together, define the level of demand and the mix of generation that the transmission system must be built. These criteria form the basis for the calculation of TNUoS charges under the current methodology. The TNUoS methodology attempts to send cost-reflective signals regarding the transmission costs that users impose on the system, by linking the charges they face to the transmission investment costs the TOs are required (by the SQSS) to make to accommodate them.

Consumers' liability to pay the year-round Demand TNUoS charge does not depend on their load factor (ie. there is no scaling by ALF as there is in the G-TNUoS charge). The Demand TNUoS methodology also has no adjustment for the degree of "sharing" of transmission assets in the year-round charge. In the G-TNUoS methodology, these adjustments seek to reflect differences in the transmission costs caused by different network users, depending on their behaviour at times other than peak (the ALF adjustment) and how the transmission costs they impose vary depending on the types of network users with which they are deemed to share transmission assets.

Paragraph 3.5.1 of the SQSS notes that the assessment of connection capacity requirements is dependent on "where the network associated with a transmission connection comprises demand connections and connections to small or medium power stations (including those in composite-user sites), group demand for future years is equal to the Network Operator's estimated maximum demand for the group which they believe could reasonably be imposed on the onshore transmission system, after taking due cognisance of demand diversity and the expected operation of any embedded small or medium power stations." [Emphasis added]

Paragraph 3.7.3 states the security contribution of small and medium power stations embedded is implicitly accounted for in the group demand established by the Network Operator as in paragraph 3.5.1 and need not be considered separately

Under the SQSS, distributed generation is clearly treated as negative demand, and should therefore be treated under charging as negative demand. It is widely accepted that the only systematic framework in which DG's contribution to demand security can be assessed is probabilistic risk modelling.⁶

In Paragraphs 4.40 through to 4.49 of its CMP264 and CMP265 consultation, Ofgem notes that distributed and transmission generation impact the transmission network identically. We do not accept this assessment. While NERA's report noted that two identical generators would have the same impact on the transmission system, NERA did not consider the impact which distributed generators have in aggregate.

As noted above, since distributed generators are treated under the SQSS as 'negative demand', and demand is treated on a diversity basis, distributed generators are considered to have

⁶ http://www.networkrevolution.co.uk/wp-content/uploads/2014/02/CIRE2013_0827_final.pdf

different investment requirements than transmission connected generators on transmission networks. This difference has not been considered or quantified in Ofgem's work to date.

The impact of distributed generation on allowed revenue recovery

Ofgem has not recognised the avoided increase in National Grid's allowed revenue, and therefore the consumer savings, resulting from avoiding new transmission-connected plant.

National Grid's Transmission Operator RIIO incentive includes allowed revenues for Load-Related (LR) capex. Variant allowances are flexed annually based on outputs to determine the allowed revenue to be recovered through TNUoS charges. Reductions in Long Run Expenditure reduces the total cost recovered from consumers.

The RIIO incentive and charging methodology for National Grid recognises the benefit that distributed generators and demand reduction brings to the transmission system above the locational TNUoS value.

This RIIO incentive is designed to reflect the cost impacts that increases in demand and transmission generation have on the transmission operator's costs. In fact, the RIIO annual report notes that "In light of the reduction in volume of demand and generation connections, NGET currently anticipates that a large amount of wider works expenditure, required to maintain network integrity within and across network boundaries, has either become unnecessary or will be deferred beyond RIIO-ET1".

Analysis by Welsh Power in its response to this consultation has found that:

- Under the Generation Connections volume driver (special condition 6F), every kilowatt of new transmission capacity, whatever the actual costs incurred, results in an increase in NGET allowed revenue of £27/kW (2009/10 prices).
- Under the Incremental wider works (IWW) (special condition 6J), every kilowatt of new transmission capacity results in an increase in NGET allowed revenue of £37/kW (2009/10 prices).
- Under non-variant load related capex, there are further reductions in NGET allowed revenue when specific works and schemes are no longer required. No estimate has yet been made of the value impact distributed generators have had on this consumer cost.
- Welsh Power estimates that inflated to 2017/18 prices per the TNUoS charging model (inflater 1.271) provides a 2017/18 generation related avoided cost of £81.33/kW. Applying National Grid's annuity factor of 0.066 gives an annualised saving of £5.37/kW (not including the unquantified impact of non-variant load-related capex).

Avoided generation residual costs on consumers

In addition to competition benefits, the displacement of transmission-connected generation with distributed generation results in significant cost savings for consumers of £15/kW in 2021. This cost saving is due to the negative generation residual being paid directly by consumers through the demand residual. Therefore, every kilowatt of distributed generation that displaces transmission generation will save consumers up to £15/kW in costs.

Avoided GSP investment

The assumed estimate of avoided GSP cost is based on insufficient data and does not include the cost of Super Grid Transformers. We have provided additional detail on this point in our response to Question 7.

Objective D – Taking into account European legislation

We disagree with Ofgem's assessment of Objective D.

Ofgem notes that European legislation requires that network charges are "cost reflective, non-discriminatory and should take into account investment costs". However, the consultation document takes no consideration of the new distortions which are created by Ofgem's proposed action, including:

- The cost reflectivity of system charges has important implications from the point of view of legal discrimination. It follows that with regard to applying different TNUoS charges, or the avoidance of those charges to different groups, it is discriminatory to treat like cases differently. This is discriminatory in two ways:
 - Onsite embedded generation and demand side users are not impacted by these modifications. Therefore it could be argued this proposal is selective discrimination against embedded generators as a subset of demand.
 - Different suppliers will face different charges for their demand portfolios, despite their charges being based on net demand under the SQSS. Further details on this point are addressed under our consideration of Objective A.
- Similarly, Ofgem has not undertaken any consideration or analysis as to whether the demand charge is cost reflective as it is applied to specific users, as would be required by Directive 2009/72/EC. For example, by reducing the triad benefit paid to generators in the south, Ofgem may be making their charge less cost-reflective than currently, in direct contravention with the Directive.

Promotion of efficiency in implementation and administration of charging methodology

We agree with Ofgem's assessment that treating new and existing generators differently will create additional administrative costs for suppliers. However, Ofgem has not quantified this cost. Neither has it quantified or mentioned supplier cost at any other point of its consultation and Impact Assessment.

We welcome Ofgem's assessment regarding phased implementation. We believe that the issues around certainty addressed above apply equally to the decision regarding whether to implement phased implementation.

Networks, social considerations and the environment

We disagree with Ofgem's assessment.

We would note that Paragraph 4.75 assumes that generation will site more efficiently as a result of these changes, which may or may not occur. For example, the removal of any locational incentive between half of the demand zones, as a result of Ofgem's zero floor proposal, could result in less efficient and higher cost networks. The evidence outlined elsewhere in this consultation response shows that WACM 4 will under-reward distributed generators, resulting in weaker signals for efficient siting of generation.

No evidence or modelling has been provided regarding whether Ofgem's proposals will increase or decrease transmission network costs or their operation.

Ofgem has made no recognition that triad payments are significantly more likely to be received by lower carbon generators, including anaerobic digestion and other bioenergy generators, gas CHP, and wind. According to Ofgem's analysis, less than 10% of distributed generation is 'conventional' (non-CHP) fossil fuel. Therefore the removal of the embedded benefit will most significantly impact lower carbon generation, including CHP and renewables.

The embedded benefit's removal will discourage future investment in these technologies, and increase the cost of capital for future investments. In addition, some low carbon operators may shut down as a result of these changes, replaced by higher carbon alternatives. Ofgem has made no consideration for these negative impacts on carbon emissions, or whether these negative impacts outweigh the assumed positive impacts noted in Paragraph 4.76.

Consumer costs

We are concerned that Ofgem's assessment of consumer costs may not be realised. We have addressed these concerns in more detail in Question 14.

We would specifically note the direct increases in consumer costs as a result of increase in transmission connected generation, outlined elsewhere in this document and totalling up to £25/kW⁷.

Ofgem has undertaken no analysis on how WACM 4 will impact wider long-term transmission network costs.

On impact of investors, we would challenge Ofgem's argument that the increase in investment risk for smaller EG is comparable with the improvement in "investment outlook" for transmission connected generation. The unexpected removal of a significant revenue stream from small generators, and the harm it delivers to existing business cases, creates significant regulatory uncertainty and harm. Sudden and unexpected harm to existing investments is far more damaging to cost of capital and investor confidence than future "investment outlook".

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

We disagree with Ofgem's assessment of grandfathering.

While investors in distributed generation can reasonably expect that TNUoS charges can change, as a result of the CUSC modification process, all CUSC modifications are subject to Ofgem approval. Therefore the expectation for regulatory certainty and clarity comes not from the CUSC process, but from Ofgem.

If Ofgem does not believe that generators should have any regard for network charging arrangements when making investment decisions, then Ofgem is arguing for the removal of locational charges entirely since its argument would make any charging signal as uninvestable.

Investors did have regard to recent Ofgem activity regarding the embedded benefit. National Grid undertook a review of the embedded benefit regime in 2013, resulting in a consultation document published in 2014. Ofgem did not take any additional action following that work group and

⁷ Includes NGET revenue increases per kW, avoided generation residual impact on consumer (£15/kW), and avoided Super Grid Transformer costs.

consultation process, nor did it in any way publicly indicate its views on the embedded benefit. By not signalling any view during that process, investors would have made a reasonable decision regarding Ofgem's regulatory position.

It is in Ofgem's interest to deliver an energy market which avoids regulatory uncertainty, where reasonable and possible. Regulatory uncertainty increases cost of capital for investment, and increased cost of capital results in higher costs on consumers, directly conflicting with Ofgem's primary mission to deliver consumer value. Ofgem directly recognised in its CMP227 decision letter that increases in regulatory risk "ultimately" cost consumers.

Cornwall Energy has noted in its consultation response that in four of the international examples of residual charging changes, the changes were implemented over longer timescales, and in two cases grandfathering was adopted.

Ofgem's modelling assumes that grandfathering will result in a reduction in consumer savings from £7.4 billion to £4.9 billion, or £2.5 billion over 15 years. However, no quantified consideration has been made of the cost to capital impact from the increased regulatory uncertainty resulting from this decision, and how this cost compares against Ofgem's assumed competitive benefits to consumers.

The impact would exist far beyond 'conventional' (non-CHP) fossil fuel generators, as a vast majority of distributed generation is renewable and does not participate in the Capacity Market. For context, Ernest and Young estimates that the UK secured £15 billion in energy investments in 2014. Every 1 percentage point increase in the cost of capital for that investment would result in an economic cost, passed down to consumers, of £150m every year. Cornwall Energy's response has undertaken similar analysis on just Capacity Market investment.

We would challenge Ofgem's argument that the increase in investment risk for smaller EG is comparable with the improvement in "investment outlook" for transmission connected generation. The unexpected removal of a significant revenue stream from small generators, and the harm it delivers to existing business cases, creates significant regulatory uncertainty and harm. Sudden and unexpected harm to existing investments is far more damaging to cost of capital and investor confidence than future "investment outlook".

We would reject Ofgem's assertion that not grandfathering improves innovation. Innovation is improved by certainty, and investor confidence supports their ability to invest in more innovative projects. The removal of certainty reduces investor appetite for more innovative projects.

Lastly, alongside this consultation, Ofgem has simultaneously published a consultation on a Targeted Charging Review, which may deliver outcomes in 18 months, and indicated it will publish a further document on a Future Focussed Strategy. The results of these reviews could be to reverse changes which are being committed to in this consultation.

However, if these reviews are delayed and do not complete in time for the 2020/2021 step down Ofgem proposes, there is a risk of existing generators closing before additional changes can be implemented. Ofgem could protect the marketplace from this outcome by grandfathering existing generators and review whether grandfathering is still appropriate following the outcome of their expected reviews.

We would specifically reject Ofgem's concern that "developers try to complete planned projects" - the application date of grandfathering on June 2017 would directly prevent this outcome, as

Ofgem's decision is expected by May 2017 and there are no conditions under which a developer can build a generation site in days or weeks.

We would also note that Ofgem has excluded in its assessment the fact that renewable generators, which receive Feed in Tariff and Renewable Obligation support, already maximise baseload generation to maximise tariff revenue or are intermittent generators. These generators are already significantly removed from market signals due to subsidy. We would recommend Ofgem consider grandfathering plant receiving these subsidies specifically, as none of the distortions noted by Ofgem would apply to them.

Options for phased implementation

We welcome Ofgem's assessment regarding phased implementation. We believe that the issues around certainty addressed above apply equally to the decision regarding whether to implement phased implementation.

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

No.

We agree with Ofgem that distributed generators should be rewarded for the avoided GSP investment they deliver. However, we are concerned that Ofgem has made no detailed assessment on the appropriate level of avoided GSP cost which should be provided to distributed generators.

Ofgem has accepted a National Grid analysis from 2014, based on 2012/13 figures, and 18 projects. We are concerned this evidence is insufficient to reach a decision on whether £2/kW is the correct figure.

For example, it is unclear why the value of the Super Grid Transformer (SGT) is ignored, as this cost will still be levied on the end consumer via distribution charges. Under Special Licence Condition 6L, it would appear that NGET receive an allowance of £3.9m for each SGT installed irrespective of whether these are paid for by the DNO. Evidence provided to Ofgem by Welsh Power show that with a likely SGT capacity of between 60MVA and 240MVA the incremental capex would be between £16/kw and £65/kw. Inflated to 2017/18 prices and annuitised this represents an additional annual embedded benefit of between £1.34/kw and £5.45/kw.

Furthermore, there are no details in the National Grid analysis on the locations of these projects, or how these charges reflect differently in different locations.

Significant further work would be required to understand if the £2/kW figure is correct and cost-reflective across different regions.

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

No.

We are concerned that Ofgem has not fully considered the impact on security of supply. Removal of a significant value for distributed generators to generate at peak demand will create significant changes in marketplace behaviour. Ofgem's assertion that "even in the worst case scenario, we

do not expect market exit by smaller EG to have a major impact on security of supply” is worrisome, as Ofgem does not state what they believe defines the ‘worst case scenario’, or how that scenario has been determined.

We would recommend Ofgem request an assessment by National Grid to fully understand the security of supply implications before considering action. The obligation is on Ofgem to understand the security of supply implications of its decision, not on industry.

For the 2 GW of generation which received CM contracts in 2014 and 2015, we agree that this capacity can likely be replaced by other capacity – however, there is evidence from KPMG that this capacity will carry a significantly higher cost than the status quo, and this cost has not been factored into Ofgem’s calculations.

Based on these risks, and with no positive security of supply benefits noted by Ofgem, we would disagree with Ofgem’s assessment that a larger reduction in payment is ‘more likely to be compatible’ to Ofgem’s statutory duties.

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

Yes. We have provided this evidence as part of our response to Question 4 and Question 5.

For avoidance of doubt, these savings include:

- vi. Sub 100 MW embedded generation is treated differently by the SQSS to larger transmission generation and therefore imposes different investment costs on the system
- vii. A reduction in the level of transmission connected generation and therefore a saving from avoiding the negative generation residual
- viii. The avoided increase in National Grid’s allowed revenue, and therefore the consumer savings, resulting from avoiding new transmission-connected plant.
- ix. A reduction in GSP costs above Ofgem’s estimate, including a reduction in Super Grid Transformer costs.

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

Yes. We have provided this evidence as part of our response to Question 4 and Question 5.

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

The ADE has no comment.

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

No.

Thermal generation, CHP and EfW impacts

We are concerned that Ofgem has not fully considered the impact of their changes on gas CHP and EfW.

Ofgem has asserted that the TDR is not “a primary business driver for such plant”, which ignores the significant impact a substantial decrease in revenue can have investor certainty, appetite for future investment, and cost of capital (and therefore cost to consumers).

Ofgem’s assertion that some investments occurred when TDR payments were much lower would be defensible only if Ofgem was proposing to lower the TDR payment to recent previous levels, such as through WACM 7. However, the complete removal of the TDR payment represents a significant change in revenue from many businesses’ investment case. Even for legacy investments, investors may have recently bought existing assets more recently, or TDR revenue may have been assumed for the wider business’ financial planning. Reductions in revenues therefore have material and substantial impacts on investors and business operations.

Ofgem’s assessment of the impact on the CHP sector is incorrect. There is more than 9 GW of CHP, when ‘Total Power Capacity’ is taken into account (as would be appropriate, since this capacity is what is actually connected and eligible for any triad benefit). This capacity includes both gas and renewable CHP. Of total CHP capacity, the ADE estimates that approximately 4 GW is below 100 MW and connected on the distribution network, and therefore eligible for the triad benefit.

While the majority of CHP ‘capacity’ is licensed generation, this capacity includes approximately 10 sites out of a total of more than 2,000, of which more than 370 are embedded in industrial sites⁸.

We estimate the removal of the TDR benefit from CHP sites, if applied to both export and on-site, is approximately £170m a year at current TDR levels. Based on survey data from industrial users, the removal of the TDR payment will result in some industrial users’ energy costs rising by 20%. These cost increases will harm these businesses ability to compete internationally. One chemical manufacturing site and one paper manufacturing site have advised the ADE they may have to close if the TDR charge is applied to their generation assets, with potential job losses in the hundreds.

DSR and storage

Ofgem’s assertion that on-site generation and demand turn down will be unaffected by these changes is disingenuous. Ofgem has asserted through this consultation that the receipt of the TDR as a payment or the avoidance of it as a charge is non-cost reflective. It has also simultaneously published further consultation on a Targeted Charging Review which is considering how to best ensure on site generators and demand response providers are unable to avoid the triad charge. Therefore the impact of Ofgem’s decision on this consultation will, in time, have a direct bearing on these other users.

While Ofgem has recognised the potential impact of its changes on existing storage operators, it has made no assessment of how its changes will impact new battery storage investments.

Renewables

⁸ Digest of UK Energy Statistics, 2016.

Ofgem has not differentiated between intermittent renewable generation and dispatchable renewable generation.

Intermittent wind generation operators and investors will have made assumptions about triad revenue. Changes in the TDR regime will negatively affect those revenue streams and their investment returns, and will therefore negatively impact confidence and cost of capital.

Dispatchable renewable generation, including biomass and anaerobic digestion, will be significantly affected, with many of these investments occurring over the last few years under the Renewables Obligation. These impacts will harm future low carbon investment.

Innovation

We agree with Ofgem that network charging should not be aimed at supporting emerging technologies. However, Ofgem must more strongly recognise that sudden and unexpected shifts in network charging arrangements can result in significant harm to the deployment of innovative technologies.

Uncertainty decreases the ability for market participants to make innovative investments. We would note that innovation tends to be supported at the smaller scale, while Ofgem's changes will re-balance the market towards larger-scale, incumbent generators, including centralised coal generation and older gas plant.

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

Ofgem has not recognised the impact these changes will have on heat network deployment. Government has committed £320m over this Parliament to support up to £2 billion in new heat network development. These investments are made significantly more economic with gas CHP, and Government's policy costing would have considered the triad revenue when setting out the business case for investment.

The removal of the TDR harms this Government low carbon investment priority, and will likely result in reduced investment than Government expected to achieve from its £320m in funding.

Question 14: Do you agree with our modelling approach?

No. This modelling only considers the impact of these changes on gas generation, and takes no account of the impact on:

- Renewable and battery storage deployment
- Changes in transmission network costs, including Super Grid Transformers and how additional transmission generation capacity increases NGET's allowed revenue.
- Increases in negative generation residual costs on consumers from increased transmission generation capacity.
- Investor certainty and changes in cost of capital

Furthermore, the modelling does not consider the fact that the changes implemented in this consultation will likely set Ofgem's path for future changes to how the residual charge is treated for on-site generation and demand response. Implementing a change without understanding the

whole system impacts from later changes is a significant oversight, resulting in a non-holistic policy assessment.

This modelling also appears to make no consideration for CHP deployment, which due to the fact it is sized to meet a user's heat demand, is almost always connected at the distribution network level. CHP capacity reduces gas demand by at least 10%. Previous work by LCP has found that 3 GW of new CHP capacity would deliver £50m in net fuel benefits.

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

No.

We are particularly concerned that the modelling has included no sensitivities, which is considered good practice to ensure the results are robust under a range of conditions.

- The assumption that gas engines are 30% efficient is incorrect, based on our understanding of the current market. Gas engines deliver efficiencies of more than 40%, with newer, high-end engines reaching 45% or higher. With higher efficiencies, the modelling would show significantly lower fuel savings from transmission-connected power plants.
- We are concerned that only the low capital cost assumptions are used for new gas generation. A higher capital cost would either mean that CCGTs remain uncompetitive, or that Capacity Market costs will have to be higher, reducing any consumer savings.
 - If Capacity Market prices are £10/kW higher than expected under the model, then the cost to consumers would be £500m more per year (assuming 50 GW of capacity), significantly reducing the predicted savings from removal of the TDR payments and wholesale cost savings.
 - However, if CCGTs do not clear the Capacity Market under a higher capex assumption, then new entry will be dominated by peaking plants. If so, the wholesale price reductions envisaged by Ofgem would not materialise, and for consumers to benefit, the savings from removing TDR payments would have to be greater than the additional CM cost. Modelling provided to Ofgem by Cornwall Energy shows that under higher capital cost sensitivities, there will be no additional CCGT capacity cleared through the Capacity Market.
- The model assumes that CCGT investors will assume they can capture future wholesale market revenues rewarding their flexibility benefits, which is an assumption which has not been born out in previous Capacity Market auctions. Capacity Market auctions have largely rewarded the lowest capital cost plant, not the lowest operating cost plant, and there has been no evidence provided that CCGTs would be able to invest against these future market revenues.

Question 16: Where WACMs are not modelled directly, do you think our assessment is appropriate?

The ADE has no comment.

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

No. Due to the reasons set out in previous questions, we would recommend that WACM 7 best facilitates the CUSC objectives. WACM 7 would deliver:

- A TDR payment of approximately £17/kW, which would most closely reflect the existing evidence of the network benefits received by distributed generators compared to transmission connected generators, including:
 - Current estimates of avoided GSP costs (£2/kW)
 - Estimate of additional avoided GSP costs from Super Grid Transformers (up to £5.45/kW)
 - The avoided cost of the generation residual caused by transmission generation being displaced by distributed generation (displacing a £7/kW payment to transmission generators, and a £15/kW cost to consumers)
 - The avoided increase in National Grid's allowed revenue, and therefore the consumer savings, resulting from avoiding new transmission-connected plant (~£5/kW)
- Significant savings for consumers through the reduction of TDR payments.
- Continued locational signals for distributed generators.
- Protection for investors and cost of capital, delivering significant benefits for existing consumers.
- A recognition by Ofgem that there are significant areas of inquiry needed over the next 18-24 months, allowing them to complete these reviews and consider next steps, and preventing unnecessary financial risk to existing generators, investors and industrial sites.

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

The ADE would prefer that additional time is taken to ensure these charging issues are addressed more holistically, and would prefer a delayed implementation date to address these issues.

As Ofgem noted in its CMP 227 decision letter that "It is not clear what the outcome of this work will be and it is possible that it will not be consistent with [this change proposal]. This could mean that legislation is implemented at the EU level that supersedes [this change proposal]. In our view, this would increase regulatory risk and, ultimately, costs to consumers."

However, if Ofgem moves forward with WACM 4 as indicated in its minded-to position, we believe there is significant uncertainty about both the long-run value to consumers and the benefits of distributed generation. The use of a 3-year phase-in is very welcome, and provides Ofgem with an opportunity to both measure the impact of its changes after each year's reduction and to better understand the key issues before the final and most harmful TDR reduction in 2020-2021.

If WACM 4 is implemented in April 2018, before necessary reviews and analysis can be undertaken, we would recommend Ofgem implement a clear, transparent process to ensure the

Targeted Charging Review and Future Focussed Strategy address specific areas of competitive or non-cost-reflective distortions which harm distributed generators and demand response providers, including the impact of distributed generators and demand reduction on:

- The cost of the generation residual
- The avoidance of the RIIO incentive's Load-Related capex
- Long-run transmission network costs
- Avoided GSP costs

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