



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

Response by E.ON

Introduction:

1. Ofgem published the minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators on the 1st March. This was followed by publication of a supplementary report by Frontier Economics on Transmission Charging Arrangements for Embedded Generation and associated data.
2. In its publication, Ofgem have considered the original proposals and various alternatives presented to them through the industry code modification process alongside thinking that has been developed through the Open Letters published and responses received. Through this, Ofgem has identified the problem as being associated with the avoidance of the TNUoS Demand Residual (TDR) tariff and its forecast escalation which results in increasing levels of embedded benefits (EBs) for embedded generators (EGs). Ofgem believes that this creates several distortions in the market to dispatch, wholesale prices, the capacity market and investment in generation which leads to higher consumer costs. Ofgem believes that EB payments to EGs also create a significant distortion between transmission-connected generation¹ and EGs.

Executive Summary:

3. E.ON agrees that the increasing levels of EBs associated with TDR avoidance are not sustainable and that changes are therefore required which will bring consumer benefits. However, **E.ON disagrees that the issue identified by Ofgem, namely the TDR avoidance, is the sole cause and believes that it is not credible to attempt to solve the problem with such a narrow focus.** The charging arrangements need to be **assessed in a holistic manner, with both the locational charge and TDR considered**, alongside the impacts to the rest of the wholesale market.
4. **The key piece of analysis that Ofgem needs to undertake, and yet has failed to do so, is a comprehensive and robust analysis as to what the absolute cost reflective locational signal should be based upon an assessment of the impact of EGs on short- and long-term network costs.** This is not something industry is in a position to do or provide evidence on as we do not have access to the required data as most of this is held by the Transmission Owners (TOs). However, it is clearly a relevant consideration for Ofgem who has the ability to access the required data and assumptions, and should conduct this analysis.
5. **E.ON contends that there are significant and underlying flaws in Ofgem's minded to decision and impact assessment.** Ofgem makes several incorrect assumptions around the cost reflectivity of the charges and fail to take account of relevant considerations around the reduction in networks costs that results from EGs on the system. Ofgem then uses a circular logic to justify these assumptions without providing any corroborating evidence and has therefore conducted an impact assessment that is neither comprehensive nor robust in nature. These issues need to be addressed before a final decision can be made otherwise there is a significant risk that competition and cost reflectivity will be undermined and unintended consequences created which require significant future work to resolve. The result of these risks would be that consumers do not see the maximum savings that could be obtained.

¹ As well as larger (<100MW) distribution connected generation.

Ofgem's Minded to Decision:

Cost Reflectivity

6. E.ON agrees with Ofgem that EBs for EGs should reflect the short- and long-term costs that have been or will be avoided by installing EGs. Ensuring that the signals that EGs (and transmission-connected generators) face are cost reflective will subsequently ensure that they are competitive signals and hence lead to a more efficient outcome and the lowest cost to consumers.
7. It is therefore imperative that any assessment of the charging arrangement starts with the correct understanding of what is and isn't cost reflective – an area in which we would strongly argue that Ofgem have jumped to an incorrect conclusion. **Ofgem assumes that the locational element of the charging arrangements is cost reflective and the TDR is simply cost recovery and therefore not cost reflective. This assumption is fundamentally flawed** and Ofgem has provided no evidence to support the argument that the locational element is cost reflective, despite the flaws being highlighted in many previous responses to its open letters.
8. The Connection and Use of System (CUSC) code sets out that the locational charge is designed to ensure that efficient economic signals are provided to Users to reflect the incremental costs of supplying them. *"These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintain a system capable of providing a secure bulk supply of energy"*². However, the locational tariffs that are derived from the DC Loadflow ICRP Transport model (hereafter the "Transport model") only account for around 10% of the allowed revenue of the transmission system. Furthermore, the demand locational tariffs account for c.£0 of the costs. Therefore, this implies either that there are no such costs placed on the system due to demand or, more likely, that these tariffs are not in fact cost reflective at an absolute level.
9. The locational tariffs that are calculated from the Transport model are intended to provide a **relative locational signal** to demand (or generation) connecting at different locations. This means that the range in charges from the north of Scotland down to the south of England is broadly cost reflective in relative terms. However, the **absolute locational signal** determined by the Transport model is based upon entirely arbitrary assumptions. Currently, the methodology uses a distributed demand reference node which means that £0 (within rounding errors due to forecast vs actual demand) is recovered through this charge. Changing the arbitrary assumptions in the model could result in all the locational charges being positive or all of them being negative whilst preserving the differential across the charges. This impact has been amply demonstrated by the report produced by the ADE, NERA and Imperial College³. This would also change the required revenue recovery from the TDR as this depends upon how much revenue is recovered from the locational charges.
10. NG's five year forecast describes how the generation and demand residual charges are calculated, based upon the allowed revenue, the generation:demand split (driven by the EU cap of €2.50/MWh) and the revenue recovered via the locational charges. The table below replicates these calculations and shows that there are significant forward looking costs contained within the TDR. **Between 2017/18 and 2021/22, the cost of the transmission system (allowed revenue) rises from c.£2.6bn to c.£3.5bn.** Some of this increase in costs is recovered from offshore and local generation charges (c.£280mn) which leaves an increase of c.£570m in the cost of the Mains Interconnected Transmission System (MITS).

² CUSC Section 14.14.6

³ Review of Ofgem's Open Letter on Charging Arrangements for Embedded Generation, NERA & Imperial College on behalf of the Association for Decentralised Energy, Section 4.1.2

Table 1: Forecast revenue recovery from residual charges based upon NG's 5 year TNUoS forecast Table 23

£mn	2017/18	2018/19	2019/20	2020/21	2021/22	Increase across period
Allowed Revenue	2632	2834	3063	3289	3476	844
Offshore & Local Connections	241	328	398	485	517	277
Cost of MITS	2391	2506	2665	2804	2959	568
Revenue Recovered from Locational Charges (G&D)	261	294	323	322.2	421	160
Revenue recovered from Generation Residual	-125	-214	-304	-436	-592	-467
Revenue recovered from Demand Residual	2256	2426	2646	2917	3130	874

11. **However, although this is an increase in forward looking costs, it is not recovered from the locational charges, but rather from the TDR.** Over the period, the demand locational charges reduce from c.£-14m to c.£-24m whilst the generation locational charges increase from c.£275m to c.£445m, resulting in an overall increase of c.£160m. This increase is more than reversed by the increase in the generation residual charges, which increase from c.£125m payments to generators to c.£590m payments to generators due to the EU cap. **It can therefore be seen, that the TDR recovers significant forward looking costs and is therefore not just a cost recovery mechanism.**
12. Another indication of the fact that the Transport model does not provide the correct absolute cost reflective signals is given by using it to calculate the notional value of the transmission system based upon the MWkm and the expansion constant. This notional value is c.10% of the allowed revenue of the transmission system. Therefore, either customers are paying considerably more than the value of the system, or rather that this is more evidence that the Transport model does not seek to provide price signals that are cost reflective in the absolute sense.
13. An alternative approach to show the lack of absolute cost signal within the transport model has recently been presented within the currently running CMP271/274 workgroup. This analysis shows the impact within the Transport model of adjusting the model such that all demand is placed in London. In this scenario, the transport model calculates that the incremental cost of shifting demand in this way is c.£0. This means that the Transport model calculates no change to the cost of the transmission system despite the fact that in reality the transmission system would need to be significantly expanded to accommodate such a scenario.
14. E.ON contends that analysis must be undertaken to determine what the **correct absolute cost reflective locational tariffs** should be before any assessment can be made on the TDR. Indeed, the purpose of the many alternatives raised through the industry modification process was to provide suggestions (as there was no time available to conduct thorough analysis) of what the correct adjustment to the locational tariffs was. This is, in effect, the values of "x" in each of the alternatives. This has been incorrectly interpreted as the part of the TDR that EGs should still receive, whereas in fact **it is the increase to the locational tariffs, signified by "x", in order to make them cost reflective in absolute terms.**
15. Ofgem does consider that avoided GSP costs are likely to provide a cost-reflective signal representing the network costs that could be avoided by building EGs. Whilst E.ON agrees with this assertion, **we do not consider that a comprehensive assessment of the full range of short- and long-term costs that could be avoided was completed either by the workgroup or by Ofgem.** Until this relevant analysis has been completed, no robust decision can be made. E.ON would suggest that the most appropriate route to

conduct this analysis would be as part of the Targeted Charging Review (TCR) that Ofgem is currently consulting on.

Network Costs

16. Ofgem's assessment does not include any consideration of the future network costs and how these might be impacted by the minded to decision. E.ON considers it inappropriate to consider changes to the charges to recover network costs without considering how the network costs themselves might change as a result. It is **simply not plausible that over the period assessed, the network costs would remain unchanged between a system that has significant levels of EG and one that does not**. Taken to an extreme scenario, in a future where the system is fully decentralised, with all demand having some form of EG, there would be no need for a transmission system and hence no costs associated with this.
17. Ofgem accepts that it is possible that having more transmission-connected generation would increase the costs of maintaining and reinforcing the network but state that any new build transmission-connected generation would likely be built at existing sites so overall the expected impact would be low. However, this therefore implies that the generation locational signal is not the determining factor of where new build generation is located as there are few existing sites in the south of England which has the lowest charges. However, EG can more easily be built in the locations closer to demand as they do not require existing sites. Therefore, whilst the costs of connecting new CCGTs to the transmission network at existing sites may not increase the transmission network costs compared to today, they would be at a higher level than if an equivalent capacity of EG was built instead. It is the comparison of these two cases that it is important for Ofgem to consider.
18. Ofgem states that, conversely to the impact on transmission network costs, they would expect the distribution network costs associated with having more EGs would increase but state that this impact has not been modelled. E.ON considers that this statement is not necessarily true as **embedded generation could reduce distribution networks costs as easily as increase them depending upon location within the network**. Indeed, distribution networks have their own set of charges to incentivise EG (and demand) to locate in this way in order to minimise, or even reduce, the distribution network costs. Should an EG locate near a high demand area, this would require less distribution network than would otherwise be the case. E.ON agrees that this is difficult to estimate but contends that not including this analysis in its assessment does not mean that the results are conservative in terms of the consumer savings.
19. **E.ON therefore believes that it is an entirely relevant consideration to include a view of networks costs and the impact on consumers as a result** and that no decision should be made until this analysis is complete. Only when this is complete can Ofgem determine what the true cost reflective signal should be and hence the required adjustment to the locational charges.

Validation of Ofgem's Principle

20. By making assumptions on the cost reflectivity of the locational tariffs (and as a result the TDR) and failing to consider the network savings associated with EGs, Ofgem has landed on a principle that they then use to underpin the entirety of the analysis on consumer benefits. This principle is that any payments to EGs above those due to the locational charge adjusted for the avoided GSP costs will be a consumer cost. The result of this principle is that consumer savings associated with adjusting payments to EGs are maximised by reducing these payments down to the locational charge adjusted for the avoided GSP costs. The modelling undertaken by Ofgem then uses this assumption as an exogenous output of consumer savings, which means the modelling itself appears to validate the assumption.
21. In practice, **this approach is fundamentally flawed and uses circular logic to self-justify an assumption around consumer savings**. What the analysis has not been able to uncover, and what any robust report would have expected to have commented on and substantiated, is around what the cost reflective level of

locational tariffs should actually be. Only then will we be able to ascertain whether there are consumer savings of the magnitude being implied by the Impact Assessment.

22. Had Ofgem assumed in its analysis that the locational signal needed to be adjusted by, say £20.12/kW (scenario 2 in its modelling), then this would deliver the maximum consumer savings associated with reducing EBs payments to EGs. Reducing payments further would actually result in lower consumer savings as it would mean that the charges were no longer cost reflective and therefore network costs would increase by more than any further consumer savings from avoided TDR payments (the exact levels of consumer savings cannot be calculated without a detailed assessment of network costs). Therefore, applying the logic used by Ofgem in the impact assessment would, under this assumption, determine that scenario 2 would deliver the greatest customer savings.
23. Similarly, if an adjustment to the locational signal is assumed to be £45/kW (scenario 1 in the modelling), then the modelling would determine that scenario 1 would deliver the greatest customer savings.
24. The tables below illustrate this impact. Table 2 gives the consumer savings in Scenario 1, 2 & 3 compared to the Status Quo scenario in real NPV terms to 2034 but omitting the assumption associated with savings due to reduced TDR payments to EGs. It can be seen from this table that the impact of the changes to EBs actually result in an overall cost to consumers in terms of the fundamental market impacts associated with CM payments, wholesale market costs, CfD costs and EEU. It is only the assumption around consumers savings associated with avoided TDR payments to EGs that result in Ofgem's modelling showing an overall consumer saving.

Table 2: Consumer Savings (real 2016 NPV to 2034 based on Ofgem's impact assessment)

£M	Scenario 1	Scenario 2	Scenario 3
CM Payments	(390)	(1997)	(2618)
Wholesale Cost	135	1709	2698
CfD Cost	(321)	(1311)	(2074)
EEU	3	(21)	(50)
Total	(573)	(1620)	(2044)

25. Table 3 illustrates the maximum consumer savings associated with 3 different adjustments to the locational tariff in order to make it cost reflective in an absolute sense. These adjustments are effectively examples of the different values of "x" that need to be applied to the locational charge. The consumer savings have been derived from the values stated in Scenario 1, 2 & 3 and are effectively the avoided triad payments at the absolute cost reflective level. As described above, reducing the payments to EGs below the absolute cost reflective level would, by definition, result in lower consumer savings than at the exact cost reflective charge. This table does not show the reduction in consumer savings that would be caused by reducing the adjustment to the locational charge beyond the assumed absolute cost reflective charge.

Table 3: Maximum consumer savings from avoided Triad payments to EGs at 3 different levels of adjustment to the locational charge (real 2016 NPV to 2034 based on Ofgem's impact assessment)

£M	Maximum savings
Triad Avoidance Payment at Locational adjusted by £45.33/kW	2384
Triad Avoidance Payment at Locational adjusted by £20.12/kW	6869
Triad Avoidance Payment at Locational adjusted by £1.62/kW	9491

26. Table 4 then shows the maximum total consumer savings by combining the consumer savings from the previous two tables. As can be seen, the maximum consumer saving is always produced by the scenario which matches the input assumption on what the adjusted locational charge should be.

Table 4: Maximum total consumer savings in each modelled scenario across 3 assumed levels of adjustment to the locational charges (real 2016 NPV to 2034 based on Ofgem's impact assessment)

£M	Scenario 1	Scenario 2	Scenario 3
Triad Avoidance Payment at Locational adjusted by £45.33/kW	1811	<764	<340
Triad Avoidance Payment at Locational adjusted by £20.12/kW	<1811	5249	<4825
Triad Avoidance Payment at Locational adjusted by £1.62/kW	<1811	<5249	7447

27. Therefore, **the modelling itself cannot validate the principle upon which Ofgem has based the minded to decision.** The only way to validate this would be to conduct comprehensive and robust analysis as to what the absolute cost reflective locational signal should be based upon an assessment of the impact on short- and long-term network costs. This is not something industry is in a position to do or provide evidence on as we do not have access to the required data as most of this is held by the TOs. However, it is clearly a relevant consideration for Ofgem who has the ability to access the required data and assumptions, and should conduct this analysis.

Competitive charges

28. Ofgem has sought to ensure that transmission network charges provide the correct signals in order to ensure competition between different types of Users on the system, with the focus being between transmission-connected generation and EGs. As Ofgem has assumed that the locational charges are fully cost reflective, this objective can only be achieved by removing the majority of the TDR as a payment to EGs with the small adjustment to reflect avoided GSP costs.
29. However, **this logic is flawed as the locational charges are not cost reflective at an absolute level but merely give relative signals between different locations.** Therefore, Ofgem should not change the charges to EGs based upon a flawed assumption with no evidence behind it in order to potentially increase competition. The primary focus should be to ensure the charges and payments faced by all parties are as cost reflective as possible as this would maximise competition. **E.ON recognises any changes to the generation locational charge are out of scope of this modification and therefore suggests any decision is delayed until a holistic analysis of all charges is completed to support such a change.**
30. Furthermore, Ofgem's focus on ensuring that the signal between transmission-connected generation and EGs should be the same is not correct. Ofgem state that analysis shows that identical flows result from connecting generation at either the transmission or distribution level and therefore if this analysis is correct, then the transmission system is affected in the same way by generation whether it is placed at the transmission or embedded level.
31. This analysis is not correct. Adding generation at the transmission level does not result in the same flows as adding generation at the embedded level. This is because **adding EG effectively reduces demand by the equivalent number of MW but in the Transport model, generation is scaled to match demand. Therefore, adding the same amount of capacity at the transmission level actually provides less capacity.** For example, a CCGT is scaled by 94% at peak and 68% at year round. Therefore, 450MW would only provide 423MW at peak and 306MW at year round. This results in different flows in the Transport model and this impact is likely to increase as greater volumes of intermittent generation are likely to lead to increased requirement for scaling, particularly in the year round scenario. Appendix A illustrates this impact with two different examples and it can be seen the flows are different.
32. In addition, **EG has a different impact on the costs of the transmission system compared to transmission-connected generation** as it does not impact the requirement around the security and quality

of the network (as defined in the Security and Quality Supply Standards (SQSS)) in the in the same way, even if at built at the same location. For example, a distributed volume of capacity across a distribution network statistically has a much lower likelihood of all being unavailable (e.g. due to simultaneous breakdown of every single unit of distributed capacity) compared to an equivalent sized, but single unit, of generation capacity (in which only 1 unit needs to breakdown for all the capacity to be unavailable). This creates different risk to the flows on the networks and the SQSS defines how this is accounted for, which results in higher levels of network reinforcement for transmission-connected generation compared to the equivalent capacity of multiple EGs. Therefore, **transmission-connected generation should face different price signals from EG** to represent this. Under the minded to decision, **by aligning the charges even though the impact on investment is different, Ofgem risk applying non-cost reflective charges in a discriminatory way.**

33. **Ofgem therefore needs to reconsider the assertion that the charges between transmission-connected generation and EGs need to be the same** based upon the current locational charge.

Negative Locational Charges

34. Ofgem considers two options for avoiding the disincentives to generate at peak times that are created by negative locational charges. If the locational charge was truly cost-reflective, then it would be appropriate that negative locational charges in certain zones reduced generation in those zones as to do otherwise would actually increase network costs. However, **because it is apparent that the locational charges are not cost reflective at the absolute level, but rather at a relative level, it is plausible that such negative charges are distortionary.** Therefore, it is appropriate to consider options to remove this distortion, an approach upon which the majority of the industry workgroup agreed (as all but one alternative sought to do this). Two options were considered:
- a. The first option considered is to apply a floor of zero to the locational charge such that it would never be a negative value. However, this approach significantly distorts the relative locational signal – the one element that is likely to be cost reflective – and therefore this does not appear to better meet the CUSC objectives nor be in consumers’ interests.
 - b. The second option considered is to rebase the locational charges by systematically increasing all the tariffs by the same amount such that the lowest charge was zero. This maintains the relative cost reflective signal between the charges, but as Ofgem recognise, it would result in a different locational signal between transmission generation and EG, unless the transmission locational signal was also changed (which is out of scope of the modification).
35. Ofgem concludes that the floor at zero approach is marginally better as it maintains the competitive signal between transmission-connected generation and EG. However, the signal faced by transmission generation is already distorted by the application of the EU cap at €2.50/MWh, which is forecast to result in the need of a negative transmission generation residual (TGR). **Avoiding a proposal which maintains the relative cost reflective signal for EGs in order to avoid a distortion between transmission and distribution generation, when the former is already distorted by a cap whereas the latter is not, is illogical and does not better meet either the CUSC objectives or Ofgem’s duties.**
36. E.ON contend that rebasing the locational signal is a significantly better way of addressing the disincentive to generate at peak that is caused by the locational signal not being cost reflective in absolute terms compared with applying a floor at zero.
37. E.ON believes that this issue is further evidence that following an approach which seeks to address one potential issue at a time is likely to create significant unintended consequences which will simply require further changes in the future to fix this. A comprehensive and robust review which considers all of the issues and their interactions would avoid this.



Ofgem's Impact Assessment:

38. Ofgem has published a draft Impact Assessment (IA) to support their minded to decision and have also published a supplementary report by Frontier Economics on Transmission Charging Arrangements for Embedded Generation along with associated data.
39. Without prejudice to the comments above on Ofgem's minded to decision, E.ON has significant concerns around Ofgem's approach to its impact assessment, the assumptions used and the failure to account for relevant considerations. Therefore, the conclusions reached by using this IA cannot be relied upon and may result in worse outcomes for consumers if not corrected. These concerns are detailed below.

Network Costs

40. Ofgem has conducted an IA on the potential impact that would result from changing the transmission network charging arrangement for EGs and yet have failed to consider the potential impact on the network costs themselves over the period assessed. E.ON has stated its concerns with this approach in its response to Ofgem's minded to position above and believe that **a robust and comprehensive analysis of the impact on network costs that result from EGs is a necessary requirement.**
41. Although E.ON agrees the current forecast levels of EBs are not sustainable and hence a reduction is likely to result in a net benefit to consumers, by failing to consider the network costs, Ofgem has inevitably determined that consumers benefit more by reducing the payments to EGs to as low a level as possible. **This is incorrect as in fact the greatest savings to customers would occur at the point at which the charges were cost reflective i.e. the EB payment to EGs equalled the network savings.** To reduce the EB payments to EGs by more than this would result in lower consumer savings.
42. E.ON would suggest that the current RIIO framework results in network costs being defined over that period and therefore changes to network costs that result from Users actions on the system are only likely to become apparent when this framework is re-visited for RIIO-2. However, this should not stop Ofgem from appropriately considering network costs in their modelling based upon assumptions and forecasts, independently from the RIIO framework.

Security of Supply

43. Ofgem has assessed the security of supply impacts that result from their minded to decision and have determined that this impact is limited with the Government's reliability standard of a LOLE of 3hr/year being met. However, Ofgem has chosen a phased implementation due to the scale of changes and the potential impact on security of supply so has recognised this as a potential issue.
44. **E.ON believes there is considerable risk associated with the minded to decision as the impacts on the economics of EG investments under such a drastic and non-cost reflective change would be substantial.** Ofgem has assumed that EG investments that currently have a capacity agreement would still deliver to this agreement despite the loss of such a substantial income stream, which their modelling suggest would result in CM payments above the levels at which this agreements cleared.
45. E.ON would suggest that this is not a prudent assumption and some consideration for non-delivery of CM agreements should be made. Making a decision which could have substantial impacts on security of supply without a more comprehensive assessment creates significant risks to the markets and consumers.

Capacity Market and Wholesale Costs

46. Ofgem has modelled the impact of the minded to decision on the CM clearing price and the wholesale market. These two impacts are inherently linked as the amount and type of capacity on the system determines (along with commodity costs etc.) the wholesale price and the wholesale price impacts the CM clearing price.
47. Ofgem recognises that a reduction to EBs would result in higher CM prices as EGs increase their bid prices and as new build units (primarily new CCGTs) are built. This then results in lower wholesale costs as the more efficient CCGTs operate ahead of older generators thereby reducing baseload power prices (E.ON notes that no consideration has been made to the likely outcome of older CCGTs converted to OCGTs to reduce costs). Whilst this logic appears consistent, the underlying assumptions made by Ofgem are not and there are several flaws to their approach.
48. For Ofgem to conduct its IA, it was necessary to make assumptions around the wholesale energy system in terms of quantities (including new build and closures) of generation and associated build costs, commodity prices, demand, interconnection etc. in order to populate the models used by Frontier Economics and LCP. All of these assumptions are uncertain and it is therefore good modelling practice to choose a number of scenarios to reflect this uncertainty and to conduct sensitivity analysis around some of the key assumptions. Ofgem has failed to follow this good practice which undermines the robustness of their results.
49. For the majority of the assumptions, Ofgem has used National Grid's (NG's) Future Energy Scenario (FES) "Slow Progression" for their analysis. This **fails to appropriately account for the plausible range of outcomes, particularly those scenarios which are consistent with the Government's objectives on meeting the 5th carbon budget**. Using a scenario such as NG'S FES "Gone Green", would see a significantly different requirement for capacity and a different resulting load factor for the new CCGTs given the level of intermittent generation assumed. This would alter the CM payments and the impacts on the wholesale price.
50. Ofgem's IA assessment shows that the changes to EBs in terms of the market impacts on the CM payments, wholesale costs, CfD costs and EEU result in a net cost to consumers which is only offset by the assumed savings in avoided triad payments to EGs. Using a different scenario such as "Gone Green" would result in different levels of costs to consumers which when combined with the consumer savings from avoided payments, may result in a different EB or value of "x" giving the greatest overall saving to consumers. It is not necessary to negate all the consumer savings from avoiding Triad payments to EGs to reach a different conclusion on what the right level for EBs should be.
51. Similarly, Ofgem needs to assume a level of costs for new build in their modelling and this is stated to be the BEIS low capex estimates (from Nov 2016). Ofgem has justified this choice based upon a validation of the model to the outcome of the Dec 2016 T-4 CM auction. In this validation, an assumption was made around the exit price for new CCGTs (it is not possible to determine exactly the exit prices as these are not published) based upon the demand curve (which has low granularity). Ofgem then states that using the BEIS low capex estimates results in new CCGTs at this exit price. Whilst the assumption for that particular CM auction may be right, this cannot be confirmed, and it is not appropriate to assume that this holds true for all future CM auctions. Therefore, **it is necessary for Ofgem to model the impacts from using BEIS's central and high capex estimates in order for the modelling to be robust**. Doing this would alter the relative costs of different technologies and impact the resulting new build decisions and CM clearing prices.
52. In order for any such analysis to be robust, **Ofgem must expand it to include such scenarios and sensitivities. Without this, the impacts on consumers cannot be relied upon.**

53. Notwithstanding the points above, based upon the extremely narrow range of assumptions used by Ofgem, the outcomes arrived at still seem implausible. The increase in CM clearing prices is in the range of c.£5-10/kW (average of £6.41/kW over the period post 2022). Given the reduction in EB payments to EGs is so significant (at least £60/kW by the 2020s) and BEIS estimate the cost of new entry (CONE) is £49/kW, it would be expected that greater increases in CM prices would be required. Some of this can be explained by the narrow assumption of only using the BEIS low capex estimates (with higher capex estimates likely to see higher CM clearing prices). Another underlying reason is the assumptions around CCGT economics that drives the CM clearing price. In its workshop on 21st March 2017, Ofgem and Frontier explained that it had been assumed that the clearing price for new build CCGTs assumed a full income from the wholesale market over the 15yr agreement. Whilst investment would be driven by a range of investors with different appetites to risk, it is implausible that all investments (to deliver the 26GW of new CCGT over the period) would take such a significant wholesale market revenue risk. Applying more conservative assumptions to at least some of this new build would result in higher capacity clearing prices. It may also result in OCGTs being more economic than CCGTs (given their lower capex) which would also impact the wholesale power prices in the modelling.
54. The IA therefore does not present a robust or convincing case that the increases in the CM clearing prices would deliver the new build CCGTs that are assumed which then resulted in the reductions to the wholesale power price. **Using a plausible, but wider, range of assumptions in these areas would likely increase the CM clearing prices which has a significant impact in terms of consumer costs given that the CM is a pay as clear auction. For example, an increase of just £5/kW to the CM clearing prices would result in a reduction to consumer savings of £2.5bn in real NPV terms out to 2034.**
55. The overall impact of these flaws in Ofgem's approach results in an overestimate of the consumer savings (or underestimate of the consumer costs) associated with the changes to the CM and wholesale price. It is entirely plausible that a more comprehensive analysis would show scenarios in which the impact of the change to EBs resulted in a net cost to consumers regarding the CM and wholesale impacts.

Ancillary Service Costs

56. Ofgem also considers the impact of their minded to decision on the balancing services market in terms of reserve costs and BSUoS charges. They conclude that these remain similar to the Status Quo scenario until the mid-2020s after which reserve costs and BSUoS charges would fall under their minded to decision relative to the Status Quo scenario. These results and the associated conclusions **appear at odds with the broad consensus in the industry that as the energy system becomes decarbonised through intermittent generation, the system will need increasingly greater levels of flexibility to manage and balance. EGs are inherently more flexible than large scale CCGTs and hence should be able to provide this flexibility at a reduced cost compared to a system without EGs.**
57. Ofgem has not published detailed statements, but suggest that reserve costs are greater in the Status Quo scenario due to higher utilisation costs of EGs. Whilst this might be true for sustained running, the increased flexibility of EGs in terms of start-up costs, ramp rates, minimum zero and non-zero times etc. means that overall, the costs of providing flexibility through EGs should be lower than via CCGTs. If this was properly accounted for, then the consumer costs associated with the wholesale market would increase thereby reducing the overall consumer savings once the avoided triad payments are accounted for. This could result in a different EB or value of "x" giving the greatest overall saving to consumers.
58. Ofgem's assessment of BSUoS charges is flawed and highlights Ofgem's lack of understanding of the relevant impacts of their decision. The conclusion is based upon the logic that the minded to decision would result in fewer EGs and more CCGTs and therefore the balancing costs would be spread over a greater volume of chargeable MWhs (given that EGs currently can avoid BSUoS charges) which results in a reduction to the £/MWh BSUoS charge. However, this conclusion is misleading as it focuses on a BSUoS

charge rather than the total balancing costs which are the key cost relevant to assessing a consumer impact.

59. **Reducing the amount of EG and replacing this with less flexible CCGTs is highly likely to increase the overall absolute cost of balancing that consumers have to pay.** The impacts described above are likely to be further exacerbated in a scenario which assumed a greater amount of inflexible intermittent generation such as the "Gone Green" FES. Therefore, Ofgem have failed to take into account this relevant consideration in their minded to decision.

Distributional Issues

60. Given the scope of the changes proposed in Ofgem's minded to decision, it is necessary to understand the distributional impacts across a range of consumers and industry participants. Given that many industrial consumers rely upon EBs to support their overall fixed costs, this change could lead to challenging economics for such consumers and even to closures which would undermine the Government's Industrial Strategy.
61. Ofgem has made some attempt at assessing the distributional impacts but have not done so in a comprehensive way. The majority of the consumer savings that the IA identifies is associated with avoided TDR payments to EGs. However, **some EGs are directly linked to industrial consumers and therefore the minded to decision would effectively re-distribute value away from these consumers to other consumers (for example, residential consumers).** Therefore, the analysis which calculates the consumer savings from avoided EB payments to EGs should be reduced by the lost payments to these, particular EGs linked to consumers, thereby reducing the overall consumer savings. In addition, behind the meter generation such as DSR will now get reduced EBs (as the TDR charge will reduce) and therefore suffers a consumer cost. This cost needs to be netted off the total consumer savings calculation.
62. Ofgem seeks to analyse the distributed impact by considering the impact on a baseload generator (A), an intermittent wind generator (B) and a peaking generator (C). It can be implied by this, that a generator A represents small scale CHP and EfW which operate year round to support industrial processes and Ofgem concludes that this type of generator is proportionally less affected by the EB change. However, once again this analysis is flawed:
- a. **Economic decisions are made upon absolute costs and revenues and not proportional costs.** Therefore the analysis should be in these terms in which case it would be shown that the absolute impact on a baseload generator is exactly the same as on a peak generator in the same GSP zone. Therefore, it is misleading to suggest that such generators and by extension industrial consumers which make use of them, are less affected. In taking this position, Ofgem has incorrectly assessed the impact on these consumers and therefore their minded to decision is based, in part, upon this incorrect assumption.
 - b. However, we do agree that an intermittent generator is much less affected given its much lower level of triad avoidance with resulting lower reduction in network costs.
63. Additionally, whilst this modification does not impact behind the meter activities such as DSR, some OSG and storage, Ofgem clearly states that it intends to consider this issue in the TCR. **If Ofgem applies the same flawed logic in this area, then such investments will be significantly undermined and reduced, disrupting the intending transition to a flexible and decentralised energy system upon which Ofgem and BEIS have recently consulted on.** For example, a key pillar of a decentralised and decarbonised system is to use the waste heat from decentralised power generation. Ofgem's minded to decision removes a significant revenue stream from investment in this area whilst maintaining the cap on transmission-connected generation (in which the majority of cases, waste a significant proportion of energy in the form of waste heat).

Response 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?*

- E.ON does not agree with Ofgem's problem definition and identified distortions. As described in our response above, Ofgem's focus on just the TDR is too narrow as it is based upon the flawed assumption that the locational charges are cost reflective at the absolute level. E.ON believes that basing the minded to decision on such flawed assumptions and narrow scope is highly likely to create a significant risk that competition and cost reflectivity will be undermined and unintended consequences created which require significant future work to resolve. As a result, this is likely to result in consumers not seeing the maximum savings that could be obtained.
- The charging arrangements need to be assessed in a holistic manner, with both the locational and TDR considered, alongside the impacts in the rest of the wholesale market.

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

- E.ON agrees that the increasing levels of EBs associated with TDR avoidance are not sustainable and that change is therefore required which will bring consumer benefits. However, as described above, Ofgem's focus on just the TDR, whilst ignoring other relevant considerations, will not result in the best outcome for consumers.

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

- E.ON does not agree with Ofgem's interpretation of the applicable CUSC objectives. It is E.ON's view that the best approach to ensuring competition is to ensure that charges are fully cost reflective and Ofgem has failed to do this by making an assumption, despite evidence to the contrary, that the locational charge is cost reflective and the TDR is not. As a result, Ofgem has incorrectly assessed the various options against the CUSC objectives.

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

- E.ON does not agree with Ofgem's assessment. E.ON has highlighted above our serious concerns that there are significant and underlying flaws in Ofgem's minded to decision and IA. Ofgem makes several incorrect assumptions around the cost reflectivity of the charges and fails to take account of relevant considerations around the reduction in networks costs that results from EGs on the system. Ofgem then uses a circular logic to justify these assumptions without providing any corroborating evidence and have conducted an impact assessment that is neither comprehensive nor robust in nature. These issues need to be addressed before a final decision can be made against the CUSC objectives and statutory duties. Otherwise there is a significant risk that competition and cost reflectivity will be undermined, unintended consequences created which require significant future work to resolve and consumers do not see the maximum savings that could be obtained.

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

- Yes, throughout our response E.ON has highlighted a number of relevant considerations that Ofgem has failed to take into account. These are summarised (not exhaustively) below:
 - Ofgem has not considered the cost reflectivity of the locational charges in an absolute sense.
 - Ofgem has not considered the impact of EGs on the short- and long-term costs of the networks.

- Ofgem has incorrectly assumed that the impact on the transmission network of EGs and transmission connected generation at the same location is the same.
- Ofgem has not considered a broad enough range of plausible input assumptions which could result in a different level of EBs or value of "x" providing the greatest consumer savings.
- Ofgem has not appropriately considered the distributional impact across different consumers.

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?*

- In principle, E.ON does not agree with the concept of grandfathering for such changes as it creates new distortions within the market.

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

- E.ON does not agree with this assessment as it fails to take into account the relevant considerations of the short- and long-term impacts of EGs on the transmission networks. The avoided GSP costs are just one element of costs that are avoided but Ofgem have not considered any others. As described above, it is not plausible to suggest that replacing 8GW of new EG in the Status Quo scenario with 8GW of new CCGT would have no impact on the transmission network costs.

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

- E.ON believes that it would be imprudent to make a decision based upon flawed analysis when the impact on security of supply could be significant. Whilst this risk may be mitigated to some extent by the phased implementation, E.ON believes a more sensible approach would be to base the decision on a comprehensive and robust analysis. Furthermore, E.ON believes that Ofgem's reliance on EGs with existing CM agreements delivering on these agreements creates a significant risk that needs to be appropriately considered.

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

- As described in our response above, the demand locational charge recovers no costs despite this charge reflecting the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy. This is evidence that it is not cost reflective at an absolute level. Further examples have been provided in our response above which illustrates a similar result.
- E.ON's view is that Ofgem needs to conduct comprehensive and robust analysis as to what the absolute cost reflective locational signal should be based upon an assessment of the impact on short- and long-term network costs. This is not something industry is in a position to do or provide evidence on as we do not have access to the required data as most of this is held by the TO's. However, it is clearly a relevant consideration for Ofgem who has the ability to access the required data and assumptions, and should conduct this analysis.

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

- As per our response to question 9, it is E.ON's view that Ofgem needs to conduct comprehensive and robust analysis as to what the absolute cost reflective locational signal should be based upon an assessment of the impact on short- and long-term network costs.

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

- Whilst E.ON does not have a contractual right for the continuation of TDR payments, we do believe that we had a legitimate expectation of them continuing above the level of the minded to decision. E.ON accepts that a prudent investor should take account of market and regulatory risks, including the possibility that TNUoS charges could be subject to change. However, the minded to decision represents such a significant change to these charges (or benefits) that we would argue it to be outside the range considered plausible by a prudent investor. The minded to decision almost completely removes the embedded benefit associated with Triad avoidance, a significant revenue stream, and were a prudent investor to consider this type of risk across all of its revenue streams, it is extremely unlikely that any investment would take place.
- Therefore, E.ON had a reasonable expectation that any changes in this area would be based upon a rational and comprehensive assessment which would limit the scale of the change compared to the minded to decision.

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

- E.ON does not agree with Ofgem's assessment of the distributional issues as described in our response above. Ofgem has not accounted for the transfer of value between different types of consumers as a result of their minded to decision and the analysis of the impact on different types of EG is flawed and misrepresents the distributional impact.

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

- In assessing Ofgem's approach, E.ON has assumed that its analysis around a baseload EG represents CHP and EfW, some of which is used by certain industrial consumers and in district heating network. However, the analysis is crude and does not extend to true consumer impacts given that the outcome of the decision could lead to closure of such industrial consumers with the associated loss in jobs and revenue for the Government.

Question 14: *Do you agree with our modelling approach?*

- E.ON has significant concerns with Ofgem's modelling approach and has highlighted numerous flaws and inconsistencies in our response above. As such, we do not believe that the results it produces and the conclusions and decisions that come from this are reliable and hence necessarily in the best interests of consumers.

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

- As described in our response above, Ofgem has chosen a narrow range of background assumptions and no attempt has been made to use scenarios and/or sensitivities to test these. Whilst the majority of the consumer savings that could occur from Ofgem's minded to decision are due to avoided TDR payments to EGs, the modelling of the impacts on CM payments, wholesale costs, CfD costs and EEU result in a net cost to consumers. A broader range of background assumptions will change, and is likely to increase, these consumer costs. This would change the results of Ofgem's IA and hence could lead to a different level of EBs or value of "x" being in the best interests of consumers.

- If there is to be a single background scenario in the modelling, E.ON believes that it should be based on meeting the fifth carbon budget. The Government will shortly be publishing the Green Growth Plan which will start to set out how the fifth carbon budget will be met, and it would seem perverse to use a FES scenario which will not meet this target. Therefore, it would be more appropriate to use the FES "Gone Green" data.

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

- E.ON believes the assessment of WACMs which are not modelled appear consistent with those that are modelled, notwithstanding the fundamental flaws within the analysis.

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

- E.ON does not agree that WACM 4 best facilitates the CUSC objectives nor Ofgem's statutory objectives.
- As highlighted in our response above, the minded to decision is based upon flawed assumptions and analysis and does not provide the most cost reflective signal for EG which would give the greatest benefit to consumers by meeting Objective B and therefore A. No attempt has been made to correct the locational charges to make this cost reflective at an absolute level as an implicit assumption has been made that the locational charge is already cost reflective. This results in a circular, and flawed, logic that suggest that the closer the EBs are to the locational charge then the better objective B is met.
- If a signal is cost reflective, then by default it should be beneficial to competition. E.ON believes that if making a signal more cost reflective means a distortion is created between other users, then the signal to other users' needs to be corrected. However, E.ON recognises that such options are out of scope of this modification which is why no decision should be made until a robust and comprehensive analysis has been completed. There is potential to complete this under the recently published Targeted Charging Review (TCR).
- At the very least, it is E.ON's view that the relative locational signal should not be distorted as this would reduce cost reflectivity. WACM 7 would achieve this and therefore better meets the CUSC objectives than WACM 4.

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

- E.ON believes the decision is based upon flawed and incomplete analysis and therefore should not be implemented but rather rolled into a comprehensive review such as proposed in the TCR.
- Should Ofgem make the final decision in May 2017, then E.ON believes that due to significant changes that are required to supplier (and other industry participants such as Elexon) systems, then implementation should be at least one whole charging year after the decision. This means the earliest implementation should occur is April 2019.

Appendix A: Illustration of flows on the Transport model

- A1. The Transport model has been used to produce a comparison of circuit loadings calculated by the Transport model at two different locations. This has been calculated using the 2017/18 Final tariffs External Model.

Circuit 1

- A2. Adding 400MW at Osbaldwick node and looked at the flows between this node and Norton and Thorston. Where the flow is positive, this denotes flow from the first named node to the second and where the flow is negative, this denotes flow from the second named node to the first. As can be seen, the higher flows occur in the year round scenario, so these circuits are assigned to year round (which scales CCGT by 68%). Therefore, the total difference in flows across the circuit is 126MW or 32% of the 400MW of generation added.

Table 5: Circuit loadings based upon the addition of 400MW transmission or embedded generation at Osbaldwick

	Peak		Year Round	
	Transmission	Embedded	Transmission	Embedded
NORT – OSBA	-131	-134	+221	+213
NORT – OSBA	-131	-134	+221	+213
OSBA – THTO	-151.6	-140	+151.8	+207
OSBA – THTO	-151.6	-140	+151.8	+207

Circuit 2

- A3. The second circuit adds 450MW at Canterbury North and looks at the flows to Sellindge, Clevehill and Kemsley. In this circuit the flows are higher in the year round scenario and hence these circuits are assigned to year round (which scales CCGT by 68%).
- A4. In these circuits, the total difference in flows is 143MW or 32% of the 450MW of generation added. This scenarios shows that the flows can therefore be significantly different, particularly in year round circuit due to the scaling applied to transmission connected generation in the Transport model. This effect is likely to increase as increasing volumes of intermittent generation require transmission connected generation to be scaled even further in the year round scenario.

Table 6: Circuit loadings based upon the addition of 450MW transmission or embedded generation at Canterbury North

	Peak		Year Round	
	Transmission	Embedded	Transmission	Embedded
CANT – SELL (1)	+51	+55	-797	-781
CANT – SELL (2)	+51	+55	-797	-781
CLEV – CANT	-102	-114	-894	-949
KEMS – CANT	-102	-114	-1106	-1161

- A5. If flows of connecting generation to the transmission system or distribution system are not the same, then the impact on the system is not the same and therefore the charges should not be the same. This undermines the principle that Ofgem have regarding the need to equalise the signals faced between transmission-connected generation and EG in order to ensure effective competition. Furthermore, in following this approach, Ofgem will reduce the cost reflectivity of the signals.