Renewable Energy Systems Limited
Beaufort Court, Egg Farm Lane, Kings Langley
Hertfordshire WD4 8LR, United Kingdom
T +44 (0)1923 299 200 F +44 (0)1923 299 299
E info@res-group.com **www.res-group.com**

Andrew Self, Energy Systems Transition,
Ofgem, 10 South Colonnade, Canary Wharf, London.
Submitted by email.

4 February 2019

Dear Andrew,

Re: RES Response to the *Targeted Charging Review: minded to decision and draft impact assessment*[1]

RES is the world's largest independent renewable energy company active in onshore and offshore wind, solar, energy storage, transmission and distribution. At the forefront of the industry for over 35 years, RES has delivered more than 16 GW of renewable energy projects across the globe and supports an operational asset portfolio exceeding 3.5 GW worldwide for a large client base. RES is responsible for 10% of the UK's onshore wind capacity, has developed 1.3GW of solar PV globally, built over 1,600km of transmission network outside the UK and become a world leader in energy storage, with 240MW of assets in operation or advanced construction stage, including 80MW in the UK. Understanding the unique needs of corporate clients, RES has secured 1GW of power purchase agreements (PPAs) enabling access to energy at the lowest cost. RES employs more than 2,000 people and is active in 10 countries.

RES wants to play an active part in GB's energy future, ensuring our projects contribute to decarbonising the energy system at least cost to the consumer, in line with RES' vision to be a leader in the transition to a future where everyone has access to affordable low carbon energy. We welcome this opportunity to respond to this consultation on the Targeted Charging Review.

We have been closely involved in the development of network charging reform through our role in the *Charging Futures Forum* Task Force on Access Rights, NGET's "Exporting GSPs" working group, CUSC modifications including CMP213 (TransmiT) and CMP192 (User Commitment), my own role as the lead generation representative (vice-chair) on the ENA's DER Connections Steering Group, and with the BSUoS Task Force.

Uncertainty over the modelled net benefit and a reform which risks moves to a smart, flexible energy system.

We support in principle moves to an appropriately more level playing field between different types of generation. However, particularly with regard the non-locational embedded benefit, we have key concerns about both the approach which Ofgem has taken and the supporting modelling which ignores any impact to new renewable generation and which assumes zero impact to investment risk. The combined impact of all changes could result in significant delay to the delivery of low-carbon generation and Great Britain's ability to move to a smart, flexible energy system that supports decarbonisation at the lowest cost – in our answers we detail where additional analysis is necessary to ensure robustness in the conclusions and to restore investor confidence in the regulatory process.

Answers to specific questions are appended below this signature. We look forward to the next steps in this reform process.

Yours sincerely,

Dr Graham Pannell
Energy Networks Lead
E graham.pannell@res-group.com
T +44 1923 299492

[1] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-minded-decision-and-draft-impact-assessment

Question 1 Do you agree that residual charges should be levied on final demand only?

We are supportive of the proposal to recover network residual charges from final demand. We welcome the likely carbon reductions which follow from removing an inappropriate incentive to operate inefficient thermal plant. We do however need consistency of implementation across all network charging reforms, to ensure that measures to increase overall competitiveness do not lead to inconsistent investment signals through piecemeal reform implementation – we explain more in our answers to questions 10-16.

Question 2 Do you agree with how we have assessed the impacts of the changes we have considered against the principles? If you disagree with our assessment, please provide evidence for your reasoning.

For the network residual charges, we broadly agree with how you have made assessments against the principles, as presented in the TCR.

However, we note that these principles have *not* been used in assessing the other proposed changes relating to non-locational embedded benefits. This appears inconsistent and less well-developed.

Question 3 For each user, residual charges are currently based on the costs of the voltage level of the network to which a user is connected and the higher voltage levels of the network, but not from lower voltage levels below the user's connection. At this stage, we are not proposing changes to this aspect of the current arrangements. Are there other approaches that would better meet our TCR principles reducing harmful distortions, fairness and proportionality and practical considerations?

For a future smart and flexible energy system, multidirectional power flows will be increasingly seen as normal. We encourage Ofgem to review any justification for all customers to make some contribution to all of the interconnected network. This review could be a second stage of work, as it would require further analysis on the whole system cost-benefit.

Question 4 As explained in paragraphs 4.41, 4.43, 4.46, 4.49, 4.80, we think we should prioritise equality within charging segments and equity across all segments. Do you agree that it is fair for all users in the same segment to pay the same charge, and the manner in which we have set the segments? If not, do you know of another approach with available data which would address this issue? Please provide evidence to support your answer

We agree that the research presented, together with evidence from other markets, suggests that this is an appropriate method to recover the costs of historic network investment, for users in a comparative segment to pay the same charge.

However, we note that the charges are in fact set per DNO region – and as a result <u>all users in the same segment will not pay the same charge</u>. For customers with a broader geographic reach this could inadvertently lead to a signal to invest in one DNO region rather than another. In keeping with the principles expressed (particularly on cost recovery) we suggest that *as far as practicable charges across different DNO regions should be equal*. This is more likely an issue with EHV system users; this unequal charging, together with the considerable range of individual needs for electricity use and capacity at these connection voltages, suggests that these users could be treated differently. We note the assessment of the Fixed Charge option presents *a factor of 13* difference between EDCM residual charges in the lowest (c.£6k) and highest charging (c.£77k) DNO region[2] and suggest that this does not represent 'equality within charging segments'.

Question 5 Do you agree that similar customers with and without on-site generation should pay the same residual charges? Should both types of users face the same residual charge for their Line Loss Factor Class (LLFC)?

We agree that the research presented, together with evidence from other markets, suggests that this is an appropriate method to recover the costs of historic network investment.

[2] Frontier subsidiary document "*Distributional and Wider System Impacts of Reform to Residual Charges" – p147.*

Question 6 Do you know of any reasons why the expected consumer benefits from our leading options might not materialise?

We read the phrase 'leading options' to represent the choice of a Fixed Capacity or Agreed Capacity charge for allocating the network demand residual: in this we agree there will be overall benefits from either implementation, and we do not oppose the summary view that the Fixed Capacity charge option will be the more beneficial of the two.

We note that by setting the charges per-DNO region, there may be an inadvertent signal to invest in one DNO region rather than another (as per our answer to question 4), which may undermine some of the suggested benefit. We note that the supporting analysis suggests a factor of 13 difference between EHV customer residual charges in different DNO regions.

However, for all of the remaining proposals – on transmission generator residual, on BSUoS embedded benefit, BSUoS charging and on Small Generator Discount – we note significant flaws in the modelling used to underpin the minded-to decisions. We detail these concerns in our answer to question 10; chiefly a flaw in not considering the impact to new renewable generation investment and the resulting change in the overall generation mix. Our initial supporting analysis shows that around 53 TWh of new renewable energy generation will be forfeit as a result of these changes. There is a disbenefit to consumers in delaying low-cost renewables, notably onshore wind, in both missed opportunity for a more competitive power price and in additional carbon costs which we have estimated at c.£600m. This analysis is explained in our answer to question 10, where we also set out why further work is required.

Question 7 Do you agree that our leading options will be more practical to implement than other options?

We agree that against the other options evaluated, the two leading options are preferable.

Question 8 Do you agree with the approaches set out for banding (either LLFC or deeming[3] for agreed capacity)? If not please provide evidence as why different approaches to banding would better facilitate the TCR principles.

Regarding *deeming* of agree capacity, we see there is a greater risk for manipulation or mistakes leading to specific customers avoiding or over-paying their share. We note limitations of currently available industry data which may make this option harder to implement fairly and accurately.

Question 9 Do you agree that LLFCs are a sensible way to segment residual charges? If not, are there other existing classifications that should be considered in more detail?

With *LLFC*, especially for HV and LV customers, we agree that this is a practical and appropriate option. However, as per our answer to question 4, it could readily be justified to treat EHV customer differently; and to this end there would be little administrative cost to group these customers differently. We are concerned that the impact assessment may have grossly underestimated the out-turn residual charge for EHV sites using the Fixed charge methodology, by failing to exclude generation sites in the denominator of the calculation[4]; we note that a significant majority of EHV sites are dedicated generation sites (not final-demand), which could have an order-of-magnitude impact on the resulting charges. The impact on user behaviour could significantly deviate from the modelled assessment as a result.

In any case, we note that LLFCs were not designed for this purpose and support a review of the impacts within a year or two from implementation.

Question 10 Do you agree with the conclusions we have drawn from our assessment of the following:

a) distributional modelling,

b) the distributional impacts of the options,

c) our wider system modelling,

d) how we have interpreted the wider system modelling?

[3] Assumed correction to the published question.

[4] Frontier subsidiary document "*Distributional and Wider System Impacts of Reform to Residual Charges" – p21.*

Please be specific which assessment you agree/disagree with.

(c) Wider System Modelling and (d) How it is interpreted

On modelling a 'fixed' programme of non-CM build

We are concerned that the impact assessment assumes FES scenarios with a pre-determined build programme of renewables (and also interconnectors and demand) - without studying the resulting impact on future generation investments and the resulting change in the generation mix[5]. The changes in costs to different generators including renewables will result in changes to future investments, which is a significant flaw in the modelling work. The Frontier report acknowledges (p53) that small change in charges can be enough to tip the economics of an investment decision for a large new build project from going ahead to not going ahead – this will certainly be the case for subsidy-free renewables which will be negatively impacted by these proposals. Indeed, Ofgem notes at 6.29:

> "[t]here is risk that these changes could lead to the cancellation of some projects, including renewable generators […] which are not yet online and which would face an increase in charges under both of our options"

Similar logic can be applied to the retirement of existing plant, in the expectation of a sustained period of decreased operational margin, leading to an overall reduction in generation capacity, tighter margins, and higher carbon emissions. By 'fixing' non-CM build-out, these issues are not correctly modelled.

We commissioned some initial supporting analysis to focus on the direct impact to delivery of new subsidy-free renewables, to test the TCR impact assessment and understand if further analysis would be justified. This narrow focus was necessary to meet the consultation deadline, and on reviewing the output we feel that further work in this area is justified. This analysis considers the TCR full-reform proposals against a background of decreasing costs for new renewables build, and hence estimates a delay to achieving price-parity for the new renewables build. Additional costs posed by the TCR means that investment in new solar, new onshore and new offshore wind will each be delayed. These non-delivered renewables do not feature in the Frontier analysis, which as a result contains a higher proportion of thermal plant to meet demand. This analysis shows that initially coal plant and latterly CCGT plant would have been displaced in the baseline case by these competitive, subsidy-free renewables, meaning that the TCR proposals incur higher carbon costs than have been suggested in the report. In summary, under the median case of NGESO's "Two Degrees" scenario, the impact of TCR full reform leads to at least:

- 53 TWh less renewable energy
- £600m additional carbon cost

This lost energy comprises approximately 10 TWh of solar, 7 TWh of distribution-connected wind and 36 TWh of transmission-connected wind which are delivered 3-4 years later than the corresponding FES scenario due to the TCR proposals. We have not modelled the resulting reduction in wholesale prices which fail to materialise as a result of these competitive plant being delayed, but there is a further disbenefit here which is missing from the TCR's impact assessment. We would be happy to share our initial supporting analysis with you bilaterally, including the results when applied to other background FES scenarios. Nonetheless, such is the scope of potential impact we will also seek a more thorough review of the proposals after the 4th February deadline.

Uncertainty affecting investment

Separately, we explain in our answer to question 11 how this consultation process may lead to a perception of regulatory risk which exceeds 'normal' investment assumptions, and that Ofgem's assertion that there is *zero* change to investment risk is unlikely to hold true. Even a very small change in perceived regulatory stability can have a very significant impact on the outcomes. We note that only a 0.2% rise in hurdle rates for new generation could lead to a 0.9% rise in the levelised cost which will in turn feed through to higher electricity prices, to an extent which would significant exceed the

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[5] Frontier subsidiary document "*Wider System Impacts of TGR and BSUoS Reforms*" – p6 "For the purposes of modelling, non-CM build (e.g. most renewable generation […]) is held constant", p10 "..we do not assume any change in the amount of new low-carbon capacity", p14 "Low-carbon-build, interconnector build and demand growth are in line with the […] 'Future Energy Scenarios'", p54 "the renewable build is locked down between scenarios as per the 'background' FES scenario."

proposed benefit. At the very least, the impact assessment supporting these proposals would be improved with a sensitivity analysis in this area.

In this regard, we note that the UK Competition and Markets Authority remarked in its 2012 price determination for Phoenix Natural Gas Ltd:

> "We are not able to quantify the effects of a lack of regulatory stability, but we consider that the qualitative evidence suggests, notwithstanding the statutory position and the right of appeal, that such an effect [to increase the cost of capital] exists and that it is not so small that it can be disregarded."[6]

We further note that Ofgem's mid-period review for RIIO-ED1 considered that the "benefits of maintaining regulatory confidence outweigh any short-term benefits to consumers", citing the evidence that reductions in 'regulatory confidence' could have the effect of increasing the cost of capital for DNOs.

In conclusion, the supporting impact assessment warrants at the very least the inclusion of sensitivity analysis for new generation investment.

(a) Distributional modelling and (b) Distributional impacts.

This was undertaken on the network demand residual only and we have not critically reviewed this element of the assessment.

Question 11 Do you agree with our proposed approach to the reform of the remaining non-locational Embedded Benefits?

We do not agree with the proposed approach. Furthermore, we believe that the process Ofgem has taken falls short of regulatory best practice, providing unnecessary uncertainty to the energy market.

Mis-stating the benefit

It is notable that Ofgem's assessment of TDR-reform benefits are predominantly *system* benefits compared to consumer benefits, implying overall productivity improvements which may be sustainable against future market changes. However, the assessment of TGR/BSUoS reform benefits are almost exclusively *consumer* benefits compared with seemingly negligible system (efficiency) benefits. Put differently, the posited benefits from TGR/BSUoS reform are expected as a result of direct wealth transfer from generators to consumers[7] and are not supported by system efficiency gains. The impact assessment requires these benefits to be sustained out to the 2040 modelling horizon and is built on assumptions that "non-CM build [capacity] is held constant across the scenarios considered"[8]. If the TGR/BSUoS reforms, or indeed other related charging reforms, adversely affect generation investment then the consumer benefit will in all likelihood be much smaller; the consumer benefit could even become negative if some combination of wholesale market prices, CM clearing prices, and other market interventions are then required to meet wider policy objectives (for example decarbonisation targets, or a smart and flexible energy system).

In our answer to question 10 we explained the concerns over the wider system modelling, notably the flawed assumption of unchanged renewables deployment, whereas the TCR proposals will add cost which will delay the delivery of subsidy-free new renewables; our initial supporting analysis shows that at least 53 TWh of 'lost' renewable energy and £600m of additional carbon costs would be incurred in implementing the 'full reform' proposals, however such is the scope of potential impact we are seeking more detailed analysis on the full proposals after the 4th February deadline.

Consultation process and perception of risk

The proposals on non-locational Embedded Benefit were not given the same opportunity for considered and open debate during the TCR process when compared with the proposals on network residual charging. These proposals are therefore less robust and less well-developed as a result. Unlike the options for the transmission demand residual, no strawmen for BSUoS, SGD nor TGR changes were presented for open discussion before this minded-to decision. As a result, specific proposals such as 'full reform' have surprised many in the industry. In totality, Ofgem's assumption that these

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[6] Competition Commission (2012), 'Phoenix Natural Gas Limited price determination', 28 November, para. 33.
[7] Ofgem Impact Assessment, Annex 7 p14.
[8] Frontier subsidiary document "*Wider System Impacts of TGR and BSUoS Reforms*" p6.

proposals represent normal 'diversifiable risk' do not hold true: considering the magnitude of all the changes, resulting in differences of TWhs of generation and £100ms of carbon cost impact under dispute. The confused messaging on BSUoS has been unhelpful in this regard.

It is not straightforward to value the cost of regulatory uncertainty, but we note that Ofgem has stated recently in its mid-period review for RIIO-ED1 that the "benefits of maintaining regulatory confidence outweigh any short-term benefits to consumers", citing the evidence that reductions in 'regulatory confidence' could have the effect of increasing the cost of capital for DNOs[9]. We feel that the breadth of impact of the TCR proposals for new generation are of a similar order to the impact of the details of ED1 for DNOs.

We have calculated previously that only a 0.2% effective increase in hurdle rate for new generation can lead to a 0.9% increase in the base cost of electricity[10], simply for the perception of regulatory uncertainty, which would completely dwarf the posited consumer savings in the TCR report. We believe therefore that this issue requires further analysis to avoid the risk of an unnecessary and potentially very costly disbenefit for consumers.

On the specific 'non-locational' embedded benefit proposals

In principle we agree with a direction of reform that appropriately levels the playing field for generators connected at different connection points across the network, however:

i. The conclusions of the BSUoS Task Force, along with previous work on BSUoS, must be considered before setting on an in-principle decision,
ii. The conclusions of the Electricity Networks Access Project in reviewing the different treatment of distribution versus transmission generators (along with considerations of effective competition with interconnected generation) must be considered before concluding the future of the SGD, and
iii. The specific implementation of any modification to 'zero' the TGR needs to be seen for stakeholders to effectively comment and consider any related consequences (which could include legal compliance and the effect on competition with interconnected generation, and the resulting wider system impacts).

BSUoS

In considering the possible outcomes for BSUoS:

- Many stakeholders hold that the majority, if not all, of balancing services charges are best recovered as a residual charge. As noted in your TCR document, if this is the case then the same principles of network residual charging can be applied. As a result, setting out a preferred option of levying BSUoS charges on distributed generation is counter-productive and provides unnecessary disruption and confusion.
- On the other hand, some elements of BSUoS may prove to be efficiently recovered on a cost-reflective basis. For this case, a targeted embedded benefit is likely justified for these elements of BSUoS. As a result, setting out a preferred option of both removing the embedded benefit and also levying BSUoS charges on distributed generation is counter-productive and provides unnecessary disruption and confusion.

In neither case is levying a BSUoS charge on distributed generation a well-evidenced position, not before the relevant work is complete. We note that Ofgem has instructed the BSUoS task force to report in May and struggle to understand the benefit of setting out any position on BSUoS before these four further months have elapsed.

SGD

As per our separate response to your consultation on the Small Generator Discount, it is evident that any 'level playing field' between these affected generators is within the scope of the Electricity Networks Access Project. Therefore, the future of charging these customers, including the ultimate future of the Small Generator Discount, would be most appropriately tied to the outcomes of this parallel work, rather than setting an expectation in the TCR.

TGR

It is challenging to address the approach nor the impact assessment in relation to the transmission generator residual when the code modification which the ESO "is developing" is yet unseen. As with all of the proposals in the chapter on

[9] Ofgem (2018), 'Decision on a Mid-Period Review for RIIO-ED1', 30 April, paras. 3.21-3.23.
[10] RES response to Ofgem's consultation "Getting More out of our Electricity Networks by reforming Access and Forward-Looking Charging Arrangements", 17 September 2018.

non-locational embedded benefit, it would have benefited all in industry for the relevant work to have been completed before presenting a position on such a substantial reform.

As a principle, we ask that you carefully consider the impact on competition not only between distribution and transmission connected domestic generation, but between GB and interconnected generation.

A poor outcome would be for Ofgem to direct a reclassification of costs paid by transmission generators simply to demonstrate compliance with both Regulation 838/2010 and the TCR document, without due consideration of the real competition between all European generation which is the purpose behind 838/2010.

Implementation and reporting

Finally, we note that implementation plays a crucial part in investor confidence and ask that all reforms are carefully signposted and communicated to avoid the additional costs of a perception of regulatory uncertainty, as explained and quantified above. For example, we would welcome assurances that reform does not undermine contracts for those already entered into the Capacity Market, or those with existing Contracts-for-Difference, assurance that overall competitiveness against European interconnected generation is not diminished and that the conclusions from other reform (particularly the Access and Forward-Looking charges work) are co-ordinated with the TCR to send a consistent and manageable message to the market.

We find it unhelpful and misleading that, while on the one hand, you have acknowledged that “the majority of the reduction in generator revenues falls on existing renewables”, on the other hand you have not modelled any impact on future (competitive, subsidy-free) renewables build, and only discussed perceived carbon savings in terms of replacing certain thermal plant with other thermal plant; as a result you have both over-stated the benefits and under-stated the additional carbon costs of these proposals.

We are concerned that your headline (first-considered) scenario is one where the UK misses binding decarbonisation targets (‘steady progression’). Whilst the report notes qualitatively that existing renewables are the most detrimentally affected group, the TCR document does not acknowledge that the decarbonisation targets are *less likely to be achieved* as a result, and the modelling omits further market intervention which would be necessary as a result, at the very least to offset these TCR impacts. This is particularly relevant to the non-locational embedded benefit reforms, due to the balance of suggested ‘consumer’ (i.e. wealth-transfer) as opposed to ‘system’ (overall efficiency) benefits.

Question 12 Do you agree with our proposal not to address any other remaining Embedded Benefits at this stage? Which of the embedded benefits do you think should be removed as outlined in xx[*sic*][11]? Please state your reasoning and provide evidence to support your answer.

We agree on a point of materiality to leave the remaining Embedded Benefits as explained at TCR 6.8. This does not prevent any party considering a revision in future through the normal code process.

Question 13 Are there any reasons we have not included that mean that the remaining Embedded Benefits should be maintained?

In our answer to question 12 we supported those benefits from TCR 6.8 remaining unaddressed on a point of materiality and have not considered these any further.

In our answer to question 11 we explained our views on BSUoS, TGR and SGD:

We explained that a BSUoS embedded benefit could be justified for any cost-reflective element of BSUoS which is identified (either through the Task Force or related work), but that it would not be justified for the proportion of BSUoS which is shown to be a cost-recovery exercise, in the manner of the network demand residual.

In relation to the TGR, we explained our view that the purpose behind Regulation 838/2010 is to support effective competition between all generators, and that it would be a poor outcome to implement a modification which artifices the classification of costs simply to meet the stated aims of the TCR without considering the effectiveness of competition between GB and interconnected generation.

[11] We have assumed this question refers to “6.8” in the TCR document.

In relation to the SGD, we explained how we supported a move to a level playing field between the affected generators, and that removal of the SGD does not create this level playing field; and that any reform to the relative charges for the affected generators must be aligned with the outcomes of the Electricity Network Access Project.

Question 14 Do you agree with our proposed approach to transitional arrangements for reforms to:

a) transmission and distribution residual charges,

b) non-locational Embedded Benefits?

Please provide evidence to indicate why different arrangements would be more appropriate.

We note that one year ahead is very short in terms of typical power purchase or electricity supply purchase, and in concurrence with item 7.13 in the report we are confident that the industry would see significantly smaller benefits than those suggested under a 2020 implementation, with the worst impact on perceived regulatory stability of the options presented.

We note that the other Significant Code Review on network access will likely also bring about a fundamental changes charging, for the great majority of network customers, and we seek the least disruptive approach to maximise market confidence.

We are also concerned that advancing the TCR proposals may bring a disbenefit of slowing the growth of local flexibility service providers, before these participants have a chance to view any potential system cost signals emerging from the Access SCR; the proposals would benefit from greater alignment with the Electricity Network Access Project to best deliver a smart, flexible energy system. The risk is that emerging DSOs will see limited or no provision of new flexibility services as a result of the TCR proposals which delay or prevent new distribution-connected plant, resulting either in inefficient network solutions or potentially the abandonment of fledgling DSO service solutions.

These reasons, taken together with our answers to previous questions, lead us to conclude:

a) For network residual charges we would support implementation in 2021.

b) We do not support the proposed approach to non-locational embedded benefit and believe significant more work is necessary to avoid miscalculation and misrepresentation of the proposed benefit. Of the two options presented, 2021 would allow time for due consideration and challenge, whereas 2020 implementation is more likely to incur the additional risk premium detailed in our answer to question 11.

Question 15 Do you agree with our minded to decision set out? If not please state your reasoning and provide evidence to support your answer.

We support the proposal that the network demand residual is best recovered only from final demand. Of the options presented, we agree that the Fixed Charge option is likely to bring the most benefit, however we have some concerns about the application to EHV customers which are not explained in the report.

We believe the proposal on the transmission generator residual needs to be developed and shared with industry before progressing further, and that the proposal should be considered holistically with regard the overall competitiveness between GB and interconnected generation which is the purpose behind Regulation 838/2010. We explain more of our reasoning in our answer to question 11.

We believe the proposal to recover BSUoS charges from distributed generation is not supported by the evidence nor the principles, and that the approach taken risks applying unnecessary and costly uncertainty to market participants. As a result, we feel this proposal should not be taken forward. We explain more of our reasoning in our answer to question 11.

We feel that the proposal to recover BSUoS charges from gross demand is ill-developed and undermined by flawed modelling. However, it could conceivably meet the main principles of the TCR, although not before further industry work is completed. We believe this proposal should be held until further work is done and the modelling flaws addressed to avoid unnecessary disruption and to avoid unreasonably delaying the deployment of new subsidy-free renewables, a detrimental change which could offset the proposed benefit. As above, we explain more in our answer to question 11.

We do not agree that it is logical to assert that the Small Generator Discount will be set to zero before related work on the charging of these affected generators is complete. We note that the Electricity Network Access Review has this review work within scope, and hence that it sends a confused message to conclude on this element without aligning with the related reform.

We believe implementation of either the network residual or any non-locational embedded benefit reform in 2020 risks baking-in a wide variety of potential disbenefits unquantified in the TCR report, and we support instead at least a 2-year horizon to allow the affected market participants to appropriately and efficiently adjust their contracts and processes.

Question 16 For our preferred option do you think there are practical consideration or difficulties that we have not taken account of? Please provide evidence to support your answer.

We note that changes to the transmission generator residual are dependent on not only the principles of effective competition between European generation but also the practicalities of legal compliance with Regulation 838/2010, and that the possibility of legal challenge and debate adds risk to the timescale and cost of implementing a TGR change.

We are aware of the complexities of changing BSUoS billing to accommodate the proposals which we understand would be a challenge for the earlier proposed implementation dates (and may also be unnecessary, as explained in our answer to question 11).