SCOTTISHPOWER

London Office
4th Floor,
1 Tudor Street,
London EC4Y 0AH
Tel: +44 (0)141 614 7501

Andrew Self
Ofgem
10 South Colonnade,
Canary Wharf,
London,
E14 4PU

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Dear Andrew

TARGETED CHARGING REVIEW: MINDED TO DECISION AND DRAFT IMPACT ASSESSMENT

Thank you for the opportunity to respond to the consultation on Ofgem's Targeted Charging Review (TCR) minded to decision and draft impact assessment. This response is submitted on behalf of ScottishPower. Our networks business, SP Energy Networks is responding separately from its perspective as a transmission and distribution network licensee.

Transmission and distribution demand residual

The main thrust of the TCR to date has been to consider how best to recover residual network costs from demand. We broadly support the three principles Ofgem has identified and we agree that the two preferred options, Fixed Charges and Agreed Capacity charges could potentially be consistent with these principles, subject to finding appropriate means of categorisation. We think that a combination of these approaches is most likely to be effective, with Fixed Charges most suitable for domestic users and Agreed Capacity for larger non-domestic users.

However, based on the distributional analysis provided in the consultation, further refinements to categorisation and charging approach are likely to be necessary to avoid apparently inequitable outcomes for certain small and medium non-domestic users. In particular, we do not think that line loss factor classes (LLFCs) are an appropriate basis for categorisation; DUoS tariff groups would be better than LLFCs but may still present challenges.

We would also note that there are significant practical considerations associated with reforming charging of network residual costs which may present challenges for Ofgem's minded-to implementation timescales. These include the fact that some fixed term products in the market already have end dates beyond April 2021, the need to modify a range of different industry billing systems and the potential need for suppliers and DNOs to reallocate large numbers of customers between categories in preparation for the changes.

Transmission Generation Residual

Ofgem is also minded to make changes under the TCR to two categories of 'embedded benefit', the Transmission Generation Residual (TGR) and BSUoS charging. For the first of these, the TGR, Ofgem's proposals involve three elements:

- revising the calculation of the TGR in light of Ofgem's decision on CMP261;
- setting the TGR to zero (with any positive TGR amount levied on demand instead);
- introducing a new negative charge or payment as required to ensure compliance with Regulation 838/2010.

Given that the TGR charge is currently negative and levied on a £/kW basis, these changes will have a disproportionate impact on transmission connected windfarms, where, because of the relatively low load factor, it will mean a substantially increased cost on a £/MWh basis. Given the magnitude of the impact, it is vital that the process for revising the calculation of TGR, which we understand is currently being developed by National Grid, is subject to full industry review and consultation. Ofgem should also give consideration to a phased introduction of TGR changes.

Changes to BSUoS

Ofgem is minded to remove the current BSUoS embedded benefit whereby distribution-connected small generators (<100MW) receive a payment for reducing suppliers' BSUoS charges which are based on net demand ('partial reform') and potentially also to levy a new generator BSUoS charge on such generators ('full reform'). Ofgem also suggests that if the BSUoS Task Force is able to identify a non-cost reflective 'residual' component of BSUoS charges, that component would be charged exclusively to demand, consistent with Ofgem's minded-to position for network residual charges.

We have serious concerns about Ofgem's proposed changes to BSUoS as we believe they are likely to result in a significant reduction in the deployment of lower cost renewables and be detrimental overall for consumers. The modelling carried out for Ofgem's impact assessment fails to take account of these impacts because it simply assumes that the volume of renewables deployed in each scenario will be constant, instead of modelling (as it should have done) the impact of the changes on investment incentives, particularly the incentives for new onshore wind (and solar) where it will not be possible to compensate for the changes with higher CfD strike prices. Even if new support schemes were to be introduced to mitigate the impact on renewables deployment, Ofgem's measure of consumer benefit fails to take into account the cost of such support and is therefore flawed.

In summary, we believe the evidence base is too weak and the risks too great for Ofgem to justify proceeding with changes of this magnitude. As a minimum, Ofgem should undertake fresh modelling which takes into account:

- the findings of the BSUoS Task Force and the proportion of the BSUoS charge that would be levied entirely on demand;
- the impact of the proposed BSUoS changes on deployment of onshore windfarms and solar PV, whether on a merchant basis (such as via a corporate power purchase agreement) or supported by a revenue stabilisation CfD;
- the additional system costs of mitigating the above, eg through increased deployment of more expensive technologies;

- the impact on overall carbon emissions, separating out the notional increase resulting from reduced interconnector imports from real increases due to reduced renewables utilisation;
- the effect of Ofgem's overall package of changes on investor confidence and cost of capital.

If this revised modelling shows the impacts we expect, Ofgem should explore with BEIS, the Scottish Government and other stakeholders how the package of BSUoS and other changes can be implemented in a way that does not jeopardise the critical role of renewables in meeting the UK's legally binding carbon reduction targets.

Yours sincerely,

Richard Sweet
Head of Regulatory Policy

Annex 1

TARGETED CHARGING REVIEW: MINDED TO DECISION AND DRAFT IMPACT ASSESSMENT – SCOTTISHPOWER RESPONSE

Chapter 4: How we reached the leading options

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

Yes, we agree that residual charges should be levied on final demand only, and we broadly agree with the assessment in Table 2 of the merits of this change in terms of the TCR principles (reducing harmful distortions, fairness, and proportionality and practical considerations).

Ofgem says in Chapter 6 that it is minded to apply this principle to the Transmission Generation Residual (TGR) and set the TGR to zero. We understand that if Ofgem were to do this, it would also introduce a new (negative) charge in order to ensure compliance with Regulation 838/2010. The current negative TGR helps mitigate the lack of a level playing field with interconnectors (and the overseas generators behind them) and it is essential that this alternative charge is introduced to avoid exacerbating these existing distortions.

Indeed, the additional network costs that are likely to be introduced in consequence of Ofgem's CMP261 decision will widen the gap between domestic renewable projects (connected at the transmission level) and those in the rest of Europe. This will make it more difficult for projects based in GB to compete to offset emissions from global companies that are committed to the likes of the RE100 campaign, and to construct projects under a zero subsidy type framework.

In this context we think there is a strong case for Ofgem to reconsider its approach to the €0-2.50/MWh range in Regulation 838/2010 and use the lower end of the range (€0/MWh) instead of the top end (€2.50/MWh).

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.

Ofgem started with four basic options for reforming the way that residual charges are levied on demand; it then created multiple variants of these options from which it shortlisted five; and finally narrowed these down to two leading options, Fixed Charges and Agreed Capacity charges. We broadly agree with the approach that Ofgem has taken to refining the options and the assessments that it has carried out against the defined criteria. We also agree the two leading options are worth considering further.

However, we would question Ofgem's assessment of the fairness of these options. In particular, the first option 'Fixed Charges (set by net volume and LLFC)' is described as 'quite equitable' and the second option 'Agreed Capacity charge (deemed capacity for small users)' is described as 'very equitable' – yet the first option is assessed as 'fairest option on balance'.[1] It is unclear to us how an option which is quite equitable can be fairer than an option which is very equitable.

[1] Consultation document Table 7, page 32

As discussed below (Question 8), we think a pragmatic approach would be Fixed Charges (option 1) for domestic users and Agreed Capacity (option 2) for large non-domestic users. However, we think that there is a significant challenge in coming up with a suitable solution for small and medium non-domestic users. The challenge is clearly illustrated by Ofgem's Figure 10 which shows the projected residual charge under Baseline, Fixed Charge and Agreed Capacity options for the following examples of small and medium (LV) non-domestic users (the latter two were shown with and without onsite generation/storage).

	User type	LLFC	Consumption
1	Microbusiness (homeworker)	Domestic	4,600kWh
2	Microbusiness (non-dom)	Small Non Domestic Unrestricted	4,600kWh
3	SME Lo	Small Non Domestic Unrestricted	CLNR median SME
4	SME Hi (1)	Small Non Domestic Unrestricted	CLNR UQ SME
5	SME Hi (2)	LV Network Non-Domestic Non-CT	CLNR UQ SME

Whilst the outcomes for Fixed Charges look reasonably fair *within* the 'Small Non Domestic Unrestricted' LLFC, the comparative outcomes between the 'Small Non Domestic Unrestricted' and 'LV Network Non-Domestic Non-CT' look distinctly inequitable. Two users with the same consumption would face Fixed Charges of £236 and £1099 respectively.

Conversely the outcomes for Agreed Capacity look distinctly inequitable between the first two LLFC categories, with two microbusiness customers with the same consumption paying £96 and £883 respectively. Indeed both Microbusiness (non-dom) and SME Lo show a very large cost increase compared to the baseline.

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?

We are not currently aware of other approaches to voltage levels that would better meet the TCR principles, though we would note that it is important that the relative residual charges at different voltage levels do not distort end users' decisions as to which voltage level they connect at.

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 with the principle of prioritising equality within charging segments and equity across all segments, but whether this will work in practice hinges on the definition of the segments. If it is not possible to define a sufficiently homogenous segment, it may be necessary on equity grounds to differentiate within the segment, eg based on capacity.

<u>Domestic users</u>

Under the Agreed Capacity option, Ofgem has assumed three indicative bands for domestic consumers, 4kVA (for the majority), 6kVA for 'higher consuming' and 8kVA for users with electric vehicles or heat pumps (para 4.20). We understand that Ofgem has defined these categories for illustrative purposes and they would be subject to refinement by industry working groups. However, based on analysis of typical domestic half-hourly demand profiles (which we have previously shared with Ofgem) we think it could be difficult to assign consumers to these categories in a robust and equitable way. Domestic consumption profiles tend to be very spiky (with a small number of half hours with very high consumption relative to the average) which means that if Ofgem wishes the categorisation to reflect usage of EVs or heat pumps (for example), it may be necessary to assign consumers to categories based on their average consumption (or specified percentile of half hourly demand) rather than peak. This in turn may create incentives for consumers to reduce consumption (eg with solar PV) and create the sort of distortions which Ofgem is trying to avoid. We therefore think a single Fixed Charge for domestic users may be more appropriate.

Non-domestic users

As explained in our response to Question 8, we think an Agreed Capacity based charge is likely to be most equitable for larger non-domestic users, accepting that this may leave some ongoing incentive to change behaviour to reduce capacity. For small and medium non-domestic users we are not aware of any categorisation which would provide an equitable basis of charging (assuming all users within the category pay a Fixed Charge).

Non-domestic users associated with generation

We would also draw attention to a particular case of non-domestic users where some form of exception may be required to avoid inequitable outcomes. An example would be a windfarm with low demand import but large generation export connected at Extra High Voltage (EHV). Currently the wind farm would pay a relatively small demand residual charge when compared to other users connected at EHV, but under Ofgem's proposals its demand charge would increase dramatically if it is categorised as EHV. Whilst this particular outcome may be mitigated by the ongoing work in CMP280, it is an example of how basing the charge on the voltage of the connection could introduce a new distortion, with the potential to make such generators unviable.[2]

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 think it is fairer for the residual costs faced by end users to reflect the value they derive from the network rather than the use they make of it. A user with on-site generation may make less use of the network than a user without (eg in kWh imported), but the user with onsite generation may derive a similar benefit in terms of the existence and availability of the network, should the on-site generation fail (the 'insurance value'). On this basis we agree that it makes sense for similar customers with and without on-site generation to pay the same residual charges.

Nonetheless, we recognise that some users have invested significant sums in on-site generation and it may be appropriate to consider transitional/grandfathering arrangements.

[2] Ofgem suggests (consultation document paragraph 4.80) that imports used for generating units or auxiliary equipment might be categorised as 'intermediate demand' rather than 'final demand' and hence be exempt from demand residual charges. However, the issue remains unless all the demand satisfies this test.

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

We agree that both lead options will have the effect of significantly reducing the ability of users to reduce their contributions to residual charges, and that this is likely to lead to longer term consumer benefits because the incentive to invest in inefficient plant to reduce grid demand in triad periods is removed. There is likely to be investment in more efficient plant because it has to be profitable without reducing residual charges.

However, we would also sound a note of caution regarding the nascent turn-down demand side response (DSR) and flexibility market. Despite the recognition that flexibility services will be critical to the future energy system, the economics of these services are challenging at present, and will be made even more challenging if opportunities from triad avoidance revenues are removed. Setting back the development of these markets could have adverse impacts on consumers in the longer run, offsetting the modelled savings.

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

We agree that compared against the other options evaluated, the two leading options may be more practical to implement.

However, as explained below (Question 8), we do not believe that any of the currently proposed options will lead to a practicable and equitable charging solution for small and medium non-domestic users (Profile Class 3-4).

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

For the reasons set out in response to Question 9, we do not support the use of LLFCs and think that DUoS tariff groups might be a better choice.

Our current view on the best approach to banding and charging is as follows:

- For **domestic users**, we believe that Fixed Charges would be appropriate as proposed by Ofgem. (As explained in response to Question 4, we have doubts about the practicability of subdividing domestic users between the suggested 4kVA, 6kVA and 8 kVA sub-bands.)

- For **large non-domestic** users we think charges should be based on Agreed Capacity; this would include half hourly metered users at LV, HV, and EHV and include former Profile Class 5-8 users with a current transformer (CT) meter.

  However, some form of exception would need to be made for users (such as windfarms) with large generation export but small demand import connected at EHV - unless mitigated by CMP280 (see response to Question 4).

- For **small and medium** non-domestic users (notably Profile Class 3-4) we think both of Ofgem's leading options for banding and charging lead to inequitable outcomes (see response to Question 2). There is too wide a range of business size (from small corner shop to large supermarket) for Fixed Charges to be equitable, and we do not think the LLFC (or indeed DUoS tariff groups) would provide effective segmentation. And Ofgem's modelling of outcomes based on deemed capacity suggested unacceptably high increases relative to the baseline and domestic microbusiness comparators. We wonder whether a possible long term solution would be to wait until the majority of such users have half hourly metering and use this data as input to some form of Agreed Capacity measure (possibly on an *ex post* basis).[3]

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?

We have a number of concerns about using LLFCs to segment residual charges and are doubtful that they would be the most sensible approach. In particular:

- There is a lack of consistency between DNOs in the use of LLFCs, with many users on legacy LLFCs which are no longer in use for new connections.

- LLFC allocations are often based on criteria unrelated to the size of the user (eg relating to details of the mater asset provider (MAP) or meter)

- Data on user allocation to LLFCs may not be reliable and could entail a substantial data cleansing exercise.

- Given the arbitrariness of some the LLFC allocations, introducing a strong price signal (such as that illustrated in Ofgem's Figure 10 for SMEs with two different LLFCs) could prompt significant demand for reallocation of users between charging categories.

In the interests of fairness there would need to be greater transparency as to how LLFCs are determined and an adequate and timely process for considering any reassignment requests (see response to Question 16).

We think that using DUoS tariff groups instead of LLFCs would avoid some of the issues above without loss of useful granularity – though may still present challenges. Where DUoS tariff groups have multiple LLFCs associated with them, it will not normally be the case that the LLFCs provide better discrimination between users from a charging fairness perspective.

Chapter 5: Quantifying the benefits of reform

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? Please be specific which assessment you agree/disagree with.

Our main concern relating to Ofgem's minded to position relates to the proposed reforms to TGR and BSUoS (the 'remaining embedded benefits') and we focus our comments on Ofgem's assessment of the wider system impact of these reforms. We offer our comments under the following headings:

- modelling of renewables investment decisions;
- consumer benefit versus system benefit;

[3] If the measure is based on some percentile of the half hourly demand distribution rather than peak, the 'peak load reduction incentive' referred to in Ofgem Table 3 could potentially be mitigated.

- investor confidence;
- other modelling issues.

Modelling of renewables investment decisions

A key weakness of the modelling carried out by Frontier is that it does not model the impact of the proposed reforms on renewables deployment. The only investment decisions included in the model are for generators that participate in the Capacity Market (CM), and investment decisions for non-CM build (including intermittent renewables) are assumed to be unaffected[4]. Deployment profiles for such generation are simply kept fixed at the levels assumed in the relevant Future Energy Scenario (FES) with CfD strike prices adjusting to reflect increased costs.

Onshore wind can provide the lowest cost form of renewable generation, lowering bills and benefiting consumers.[5] In order to deliver the volumes of onshore wind required to meet GB's future energy needs, a combination of mechanisms including "revenue stabilisation" CfDs and corporate power purchase agreements (PPAs) will be necessary. The need for such measures to bring forward low cost renewables will be increased if (as seems likely) slow progress with new nuclear projects results in a 'carbon reduction gap' in the 2030s. However, with no CfD auctions currently planned for onshore wind (or other low cost renewables), there is no opportunity to mitigate the impact of charging reform through adjusted CfD strike prices. Furthermore, the corporate PPA route to market is subject to increasing competition from overseas projects (see response to Question 1), where the proposed reforms will place GB projects at a greater cost disadvantage (not helped by the increased uncertainty around the ongoing Brexit negotiations). The risk of hindering the long term outlook for further deployment of onshore wind, and other low cost renewables projects is therefore acute.

The pipeline of future onshore wind projects is likely to involve a high proportion of embedded projects, given that most of the larger sites which would be suitable for transmission connection have already been developed. The circa £5/MWh increased costs resulting from full BSUoS reform would have a serious impact on the viability of such embedded generation. In addition, as we move into the 2020s, the potential impact of the proposed changes to the charging arrangements on decisions in relation to repowering of existing projects could be significant. Indeed, Ofgem notes that:

> '[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'[6]

By the same logic, the proposed reforms could also affect the retirement of existing plants if operating margins are expected to decrease for a sustained period. The implication of this would be that overall generation capacity could fall, leading to tighter capacity margins and/or higher carbon emissions, none of which appears to be captured in the Frontier model.

Given the strong interest of future consumers in reducing carbon emissions, we do not think it is consistent with Ofgem's statutory duties to overlook the impact on intermittent renewables deployment in reaching its minded to position.

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[4] Although consideration is being given to including non-subsidised wind and solar generation in the CM, the likely derating factors are so small that this will not be a material consideration.
[5] Eg see BVG Associates Report https://bvgassociates.com/the-power-of-onshore-wind/
[6] Ofgem (2018), 'Targeted charging review – minded to decision and draft impact assessment', November, 6.29.

Consumer benefit versus system benefit

The two sets of proposals that Ofgem is minded to implement – network demand residual reform and the combined TGR/BSUoS reforms - are modelled as having very different welfare impacts. The network demand residual reforms are expected to have significantly greater system benefits compared to consumer benefits whereas the TGR/BSUoS reforms have substantial consumer benefits compared to almost negligible system benefits.

In other words, the network demand residual proposals will result in a sustainable increase in the productivity of the system overall while the TGR/BSUoS reforms will have almost no discernible positive impact on productivity. Instead, the benefits to consumers from the TGR/BSUoS reforms will largely be the result of a welfare transfer from generators, something that Ofgem has also acknowledged.[7]

In this context Ofgem concedes that:

> 'Frontier and LCP, our consultants, have indicated that the system savings provide the most robust estimate of benefits from reform. There is a greater deal of uncertainty associated with the consumer benefits estimates as some of the elements of consumer cost, in particular costs associated with the capacity market (CM), are inherently unpredictable.'[8]

We agree with Ofgem's consultants and would note that the concerns raised about uncertainty of consumer benefits are particularly relevant in a context where dynamic effects (such as changes to investment incentives) are not being properly modelled. Any welfare transfer of this magnitude can be expected to result in significant rebound effects, such that when a new equilibrium is reached, the magnitude of the welfare transfer is much less than originally modelled.

As we have noted above, the assumption that 'non-CM build is held constant across the scenarios considered'[9] means that Ofgem is implicitly assuming that the welfare transfer associated with these reforms will not substantially affect investment and retirement decisions over the modelling horizon. In other words, Ofgem's estimate of the TGR/BSUoS reforms assumes that welfare transfers to consumers from existing and future generators would continue until at least 2040.

Clearly, if the TGR/BSUoS reforms do adversely affect renewable generation investment, consumers would only benefit from the welfare transferred from existing generators (not future generators) and the consumer benefit would in all likelihood be much smaller. Indeed, the consumer impact could conceivably be negative if some combination of wholesale market prices, CM clearing prices, and other renewable subsidies were required to increase to meet wider policy objectives (ie reducing carbon emissions and maintaining an acceptable loss of load expectation (LOLE)).

Investor confidence

One particular aspect of the reform that can materially affect future generation investment is the lack of clarity on how the TGR will be set to zero in future. Depending on the precise approach taken by Ofgem and National Grid to achieve this, further charging reforms could have significant adverse impacts on consumers, generators, and the system overall.[10] In

[7] See Ofgem Impact Assessment, Annex 7, p.14
[8] 'Targeted charging review: minded to decision and draft impact assessment', para 5.15
[9] Frontier and LCP (2018), 'Wider System Impacts of TGR and BSUoS Reforms', November, p.6
[10] National Grid (2018), 'Compliance with European Regulation 838/2010 Part B: Guidelines for A Common Regulatory Approach to Transmission Charging', 30 May

particular, this reform could affect generators very differently, potentially compounding the perception of regulatory uncertainty.

Ultimately, this regulatory uncertainty will make project cash flows more uncertain. Depending on how an investment project is appraised, this uncertainty can manifest itself in investors either adjusting downwards their expectations of project cash flows or utilising higher hurdle rates. In either case, the pool of potentially investable projects and technologies could shrink.

In the case of generation investments characterised by high sunk costs, the impact of greater uncertainty over future regulation can significantly increase the value of deferring a project. To the extent that investors exercise their 'option' to defer investment, this could decrease the value of consumer and system benefits in Ofgem's analysis, either because 'marginal' projects are not taken forward, or because the realisation of the modelled benefits is delayed (and so discounted more heavily in Ofgem's impact assessment (IA)).

Similarly, the uncertainty over future charging arrangements remains elevated as a result of Ofgem's wide ranging review of electricity network access and charging, including the potential for further BSUoS reform.

While valuing the cost of regulatory uncertainty is not straightforward, it is worth noting that the UK Competition and Markets Authority (previously the Competition Commission) has previously opined on this matter in the Phoenix Natural Gas Limited appeal. It stated:

> "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."[11]

In addition, in the context of its decision on the mid-period review for RIIO-ED1, Ofgem has also recognised 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.[12]

Although we recognise the challenges in deriving any quantitative estimate of reduced investor confidence, we think that it should be considered in Ofgem's overall assessment.

<u>Other modelling issues</u>

We are strongly of the view that the modelling carried out by Ofgem/Frontier is insufficiently robust to support Ofgem's minded to position on TGR/BSUoS. Ofgem needs to commission further modelling to investigate properly the impact of the proposed reforms on renewables deployment and the UK's legally binding carbon reduction commitments. We note below a number of additional features of the modelling which we believe would be appropriate to address in any further modelling work:

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- <u>Compliance with Regulation 838/2010</u>: As Ofgem notes[13], Frontier's model does not take account of the proposed mechanism to ensure continued compliance with Regulation 838/2010, and the consumer costs savings may therefore be smaller than stated

[11] Competition Commission (2012), 'Phoenix Natural Gas Limited price determination', 28 November, para. 33
[12] Ofgem (2018), 'Decision on a Mid-Period Review for RIIO-ED1', 30 April, paras. 3.21-3.23
[13] TCR Annex 5, para 1.70.5

- Network costs: Frontier explains that new plant is assumed to be built in a 'generic GB' location and for the purposes of their system cost analysis, they do not quantify the network cost impacts as they are highly sensitive to changes in the assumed build locations of new plant.[14] Even if it is too complex to model in detail, we think it would be appropriate for Ofgem to provide more detailed reasoning as to why this is a safe approximation to make, given the high sensitivity.

- Carbon emissions: Ofgem's assessment predicts a significant increase in carbon emissions which appears to be driven by two main factors: replacement of interconnector imports with domestic production; and a reduction in storage capacity leading to reduced output from wind generation. Ofgem implies that the former is artificial (as imports are deemed to have zero emissions) and the latter would be addressed by reforms to storage charging outside the scope of the assessment. We think it would be helpful if Ofgem could provide a separate estimate of the impact on carbon emissions of reduced investment and/or reduced utilisation of renewable generation plant.

Conclusion

In conclusion, we believe the evidence base is far too weak and the risks too great for Ofgem to justify proceeding with changes to embedded benefits of the magnitude proposed. We believe Ofgem should undertake fresh modelling which takes into account:

- the findings of the BSUoS Task Force and the proportion of the BSUoS charge that Ofgem is proposing would be levied entirely on demand;
- the impact of the proposed BSUoS changes on deployment of onshore windfarms and solar PV, whether on a merchant basis or supported by a revenue stabilisation CfD;
- the additional system costs of mitigating the above, eg through increased deployment of alternative technologies;
- the possibility that the assumed welfare transfer from generators to consumers may be eroded by offsetting changes to CM clearing prices etc;
- the effect of Ofgem's overall package of changes on investor confidence and cost of capital;
- the impact on overall carbon emissions, separating out the notional increase resulting from reduced interconnector imports from real increases due to reduced renewables production.

Chapter 6: Remaining embedded benefits

11. Do you agree with our proposed approach to the reform of the remaining non-locational embedded benefits?

We do not agree with Ofgem's proposed approach to the reform of BSUoS charging arrangements, and we have concerns about the process for reforming the Transmission Generation Residual (TGR).

BSUoS reforms

Our main objection is that the proposed reforms are likely to reduce future low cost renewable energy and flexibility deployment at distribution level, which in turn would reduce

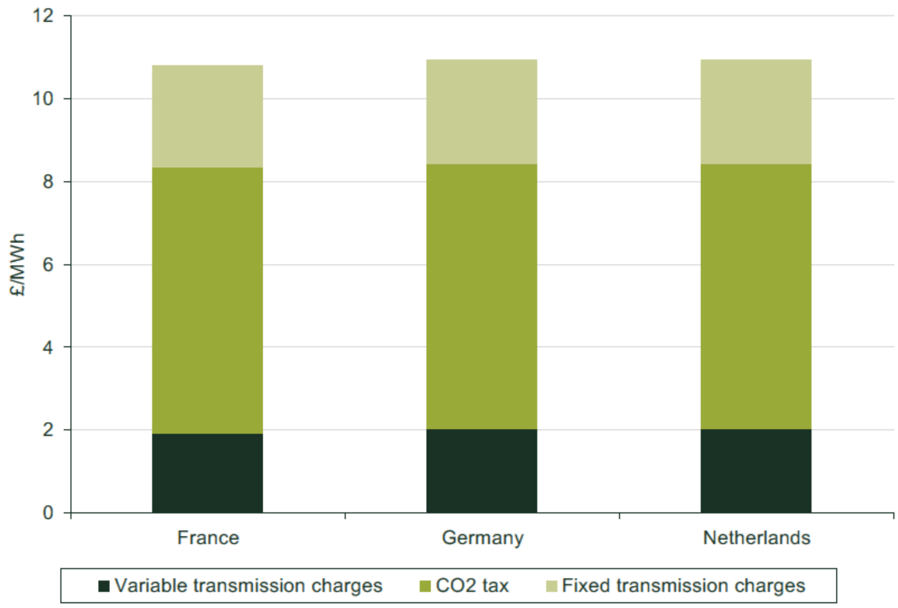
[14] Frontier 'Wider System Impacts of TGR And BSUoS Reforms', page 15

the UK's ability to meet carbon reduction targets at an affordable cost. (Based on analysis undertaken on behalf of the renewables industry, full BSUoS reform would reduce revenues and increase operational costs for small embedded renewables by £96m per annum). As explained in response to Question 10, Ofgem's IA fails to model this at all, and therefore potentially overlooks a very serious consumer detriment that would need to be weighed against any consumer welfare increase.

Furthermore, as explained in response to Question 10, the IA case for remaining embedded benefits reform rests on welfare transfer rather than increased system efficiency, and there are doubts about the robustness and sustainability of such effects.

Ofgem justifies the proposed reforms on the principle of avoiding distortions between transmission and distribution connected generation. We agree that this is an important principle, but it is also important to avoid (or minimise) distortions between GB-based generation and overseas generators. While 'full BSUoS reform' may level the playing field between transmission and distribution connected generation, it exacerbates the lack of a level playing field with interconnectors (see Figure 1).

Figure 1 - Additional costs of electricity generation in Great Britain relative to selected EU member states – (December 2015)



Source Oxera - Impact of an uneven playing field for power generation in Great Britain and connected markets

We believe Ofgem should hold off making any decision on reform of TGR/BSUoS charges until after the BSUoS Task Force has reported and Ofgem has refreshed its IA as proposed in response to Question 10 above (including the impact of any changes resulting from the BSUoS Task Force).

Furthermore, instead of its proposed reforms, we believe Ofgem should consider an alternative option, to remove BSUoS entirely from generation. This would better address the current lack of level playing field with overseas generation and would also remove the remaining embedded benefit for non-exporting onsite generation.[15] Given that BSUoS does not appear to send a meaningful signal to generators there would be no loss of efficiency from such a change.

15 Ofgem TCR Annex 5, page 3, FN4

Finally, given the magnitude of the impact, it is vital that the process for revising the calculation of TGR, which we understand is currently being developed by National Grid, is subject to full industry review and consultation.

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? Please state your reasoning and provide evidence to support your answer.

Yes, we agree with Ofgem's proposal not to address any other remaining embedded benefits at this stage. Ofgem and industry have tackled the issue of embedded benefits and achieving a level playing field in the order of greatest significance and materiality. The Transmission Demand Residual benefit is being addressed through CMP264/5. The TCR is now addressing the next most significant benefit in avoided Demand BSUoS charges. The remaining embedded benefits identified in Ofgem's open letter of July 2016 (RCRC, AAHEDC and Transmission Losses) are of lower materiality and could be addressed by industry or Ofgem at a later date if appropriate.

<u>Transmission Generation Residual (TGR) reforms</u>

Ofgem's proposed TGR reforms involve three elements:

- Revising the calculation of the TGR in light of Ofgem's decision on CMP261;
- Setting the TGR to zero (with any positive TGR amount levied on demand instead).
- Replacing any negative TGR amount required to ensure compliance with Regulation 838/2010 with a new negative charge or payment.

Given that the TGR charge is currently negative and levied on a £/kW basis, these changes will have a disproportionate impact on transmission connected windfarms, where, because of the relatively low load factor, it will mean a substantially increased cost on a £/MWh basis. Given the magnitude of the impact, it is vital that the process for revising the calculation of TGR, which we understand is currently being developed by National Grid, is subject to full industry review and consultation. As noted below, Ofgem should also give consideration to a phased introduction of TGR changes.

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

As explained above, Ofgem has not assessed the impact of the proposed changes to remaining embedded benefits on the deployment of low cost renewable energy projects (onshore wind and solar PV) which are not currently eligible for CfD support. Depending on the results of this assessment there may be a strong case for maintaining the remaining embedded benefits, at least until alternative mitigation measures can be put in place.

Chapter 7: Transitional Arrangements

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.

Transition and distribution residual charges

We agree that Ofgem is correct to rule out an implementation date of 2020 as it would not be practicable to make the necessary industry-wide changes in time.

Of the two options Ofgem is consulting on, we think the phased implementation (2021 to 2023) may be preferable to implementation in 2021. Although the consumer cost savings are less for the phased implementation, the system costs savings (which Ofgem's consultants consider to be more robust) are slightly higher. Furthermore, given the potentially large distributional impacts of the changes, a phased approach which gives affected consumers a better opportunity to mitigate or adapt to cost increases should be weighed against the average impact on consumers.

However, as noted in response to Question 16, there are a number of practical considerations which suggest that it may not be realistic to implement before April 2022:

- the fact that some fixed term products in the market already have end dates beyond April 2021;
- the need to modify a range of industry billing systems;
- the potential need to reallocate large numbers of customers between categories;
- potential interactions with the review of access and forward looking charges (RAFLC);
- potential interactions with CMP280.

A start date of April 2022 may also be significantly less complex than the phased implementation option.

Remaining embedded benefits

For the reasons given above, we do not believe that Ofgem should commit at all to implementing these reforms until it has properly considered the impact on low cost renewable generation.

Should Ofgem decide to proceed, we believe the most appropriate option of those considered would be phased implementation between 2021-23. This would allow more time for implementation (reducing the risk of unintended disruption) and would give affected generators more time to adapt to or mitigate any cost shock. As noted above, a single implementation date of 2022 may also be worth considering, as an alternative way of mitigating disruption.

Chapter 8: Our 'minded to' position

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

Transition and distribution residual charges

We broadly agree with Ofgem's direction of travel in its minded to decision, but believe further refinement of the approach to categorising end users (and applying residual charges accordingly) is required to avoid highly inequitable outcomes (such as those highlighted in our response to Question 2).

As noted above (response to Question 8) we think that a single Fixed Charge could be appropriate for domestic users and Agreed Capacity charges for larger non-domestic users, but we think further consideration needs to be given to the treatment of small and medium non-domestic users.

Remaining embedded benefits

We do not agree for the reasons set out above. Full BSUoS reform will increase costs to consumers as it will impact future investment in the lowest cost renewable energy projects. Partial reform removes the most significant element of distortion but mitigates the extent to which existing investments are penalised and investor confidence can be maintained for future projects.

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.

Transition and distribution residual charges

We have identified a number of significant practical considerations for implementation of the residual reforms which will need careful consideration. As noted above (Question 14), these may have implications for how early the reforms can realistically be implemented:

1. Fixed term products: Suppliers will need sufficient advance notice of changes to network charging that they can reflect them in their fixed term tariffs. ScottishPower already has domestic and SME products that are fixed beyond April 2021 and we will be launching more soon. This suggests that changes should take effect no earlier than April 2022, with a clear and early steer to suppliers that this will be the case. (Clearly, where suppliers have a sufficiently large and representative cohort of customers in a particular category, the gains and losses may average out. But even then, suppliers will be exposed to customers who are now being 'overcharged' switching supplier and those who are being 'undercharged' staying put.

2. Billing systems: As part of the Significant Code Review process it will be necessary for industry to consider how long it will take to modify relevant billing systems (supplier, Elexon, National Grid and DNO) to accommodate new residual charges (potentially also taking into account the need for parallel implementation of changes to access products and forward looking charges). It is difficult to comment on the timescales until there is further clarity on the detail of the reforms, but Ofgem may wish to investigate this further before confirming its decision on implementation timescales.

3. Reallocating customers to different categories: Depending on how the charging categories are ultimately defined, a significant number of customers may ask to be reallocated to a new category that attracts lower charges. This could happen if there is any arbitrariness in the initial category allocation or if customers' characteristics have changed over time – or indeed as a result of data quality issues. As soon as charging differentials are introduced (particularly if they are as sharp as some of Ofgem's modelling suggests) customers (or third party intermediaries (TPIs) acting on their behalf) are likely to make such requests, and potentially expect charges to be adjusted retrospectively. We think there could be parallels here with the experience of BSC modification P272 which led to a significant workload for suppliers and DNOs over a sustained period. If similar issues arise here, suppliers and DNOs will need to be given sufficient time to address these issues before new charges take effect.

4. Interaction with RAFLC: Given the magnitude of the potential impact on network users of the TCR reforms and any reforms to be introduced as a result of the review access and forward looking charges (RAFLC), it will be important that network users who are most affected are able to assess the full enduring impact on their businesses from both sets of reforms. Implementation on different timescales may lead to unanticipated short-term impacts and there may be a case for aligning timescales.

5. Interaction with CMP280. As noted above (Question 4), the reforms could have unintended consequences for a windfarm connected at EHV which also a small demand requirement, and which could face a dramatic hike in demand residual charges. This could be resolved by CMP280 (which would remove demand residuals from generators and storage) but could create a project dependency.[16]

Remaining embedded benefits

Practical considerations for implementation of the reforms to remaining embedded benefits (TGR and BSUoS) will include

1. Interaction with BSUoS Task Force: As Ofgem recognises, the 'full reform' option will have material implementation costs which is an additional reason why no decision on full reform should be taken until the BSUoS Task Force has reported and there is a clear way forward on treatment of BSUoS residual costs.

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[16] Ofgem suggests (consultation document paragraph 4.80) that imports used for generating units or auxiliary equipment might be categorised as 'intermediate demand' rather than 'final demand' and hence be exempt from demand residual charges. However, the issue remains unless all the demand satisfies this test.