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Andrew Self
Targeted Charging Review
Ofgem
9 Millbank

4 February 2019.

Sent by email to: TCR@Ofgem.gov.uk

Dear Andrew,

Re: Targeted Charging Review minded to decision

Thank you for the opportunity to respond to the above consultation. This is a non-confidential response on behalf of the Centrica Group.

It is in the long-term interests of customers that network charging arrangements are built on a sound economic basis. Ofgem's proposals are seeking to remove distortions that currently exist and put in place robust arrangements. This should, over time, lead to the efficient development of the electricity system.

So, we are supportive of what Ofgem is attempting to achieve and welcome these proposals in principle. However, in practice, we are concerned that some of the proposed changes will have a wider detrimental impact on customers. This is due to the negative impact on the investment environment for flexibility, especially given that the investment case for distributed energy resources (DER) is already challenging. We therefore believe it is essential to take these points into consideration:

- The proposed changes will have a significant impact on current and potential local flexibility projects. Other recent GB energy policy changes have already materially impacted the investment environment.
- The proposed changes need to be managed carefully to avoid a long-term detrimental impact on customers due to a stalling in the deployment of flexible solutions needed to ensure GB meets its targets.
- Residual reform should be implemented alongside other regulatory changes and market developments required to allow flexibility service providers to access alternative revenue streams.
- Residual reforms should be implemented from April 2023 to coincide with the next electricity distribution price control and the Electricity Network Access Project (ENAP). This

should also allow for market developments, such as further competitive procurement of balancing services and new local flexibility markets.

The importance of flexibility to customers

Energy flexibility and smart networks have the potential to provide significant value to the UK economy, save money for consumers and contribute to decarbonisation.

Research commissioned by Centrica found that if just three sectors of the UK economy – healthcare, industry and hospitality and leisure – adopted flexible distributed energy solutions they could achieve almost £1bn of savings on annual energy spend, while delivering an £18.5bn boost to the country's overall economic growth and creating 260,000 new jobs[1]. Distributed energy solutions in these three sectors could also deliver annual emissions savings of 7.2 MtCO2e, equivalent to 11 per cent of the three sectors' current carbon footprint.[2] By 2030 that would represent a three per cent reduction of the UK's entire Carbon Budget.

This is consistent with the findings of other organisations. For example, analysis by Imperial College London with the Carbon Trust for Government suggested the UK could save £17-40bn across the electricity system from now to 2050 by deploying flexibility technologies. The net benefits (after costs) are predicted to be in the range of £1.4 to £2.4bn per year by 2030.[3] The Association of Distributed Energy (ADE) calculates that 16 percent of the UK's peak electricity requirement – or 9.8 GW – could be provided just by businesses being flexible in their energy demand, which could save UK energy consumers £600m by 2020 and £2.3bn by 2035[4].

The value of flexibility is also supported by figures from The Committee on Climate Change that identified deploying flexibility technologies could result in needing up to 10 GW less of peaking plant to meet demand in 2030. The importance of system flexibility and local flexibility was also made clear in Greg Clark's speech on the Future of the Energy Market last year and within the Government's Clean Growth Strategy.

Understanding changes in the wider context

To maximise value, flexibility services and smart technology need to be delivered through market mechanisms and markets need to be allowed to work. The UK needs an environment that encourages industry to bring forward more products and services. This will allow, through the DNOs' neutral market facilitation role, the emergence of liquid markets for flexibility. To date, there is limited evidence of progress. The potential benefits are under threat if businesses cannot make the case for investing in energy flexibility. Whilst the UK energy market is evolving rapidly, the pace of change makes it fragile.

[1] Centrica Business Solutions report '*Distributed Energy: Powering Britain's Economic Future*' November 2017

[2] Centrica Business Solutions report '*Distributed Energy: Powering Sustainability*' October 2018

[3] Imperial College London. Carbon Trust '*An analysis of electricity system flexibility for Great Britain*' November 2016

[4] Association of Distributed Energy report '*Flexibility on demand: Giving customers control to secure our electricity system*' July 2016

Simultaneously, we need to remove the current barriers and distortions to allow markets for flexibility to flourish. This needs careful coordination to avoid removing current incentives and revenue streams from flexibility service providers before they can access future alternatives. Otherwise the UK risks stalling the deployment of flexible solutions to the dis-benefit of consumers, the economy and the environment. For example, a DNO may find that, in the absence of flexible services, it is necessary to reinforce the local network to accommodate renewables or EVs. This may not be the optimal solution and it also "sterilizes" the value opportunity for the end consumer over the life of the network asset. Given current uncertainties, and the lead time for network reinforcement, reinforcement is potentially a "high regrets" solution, and in the event the need for the reinforcement does not materialise these costs are stranded.

BEIS and Ofgem need to adopt a coherent whole systems approach that is mindful of the holistic impact of policy decisions, and follows a "least regrets" path to delivery of the UK carbon budgets at optimal cost to consumers. The Targeted Charging Review (TCR) risks removing the incentives for investment in the flexibility, before replacement sources of revenue are brought forward.

To achieve a flexible energy system, we need to create a positive investment environment. We support the rationale for change, but changes need to be timed so that investors don't lose confidence in the market. The investment case for distributed energy resources (DER) is currently challenging. The Capacity Market (CM) is suspended. Transmission network flexibility markets are developing while local flexibility markets are largely undeveloped. Demand-side response (DSR) customers are facing the loss of core revenue streams from embedded benefits, with a prolonged delay before policy makers decide on alternatives.

Industry reform implemented in an uncoordinated fashion can weaken regulatory confidence. The importance of regulatory confidence was recognised by Ofgem in its decision last year not to extend the scope of the RIIO-ED1 Mid-Period Review. Despite identifying tangible short-term consumer benefits of £322m, Ofgem rejected the option to extend the scope of the review because it was concerned it could undermine regulatory confidence, weaken incentives on DNOs, and result in increased costs in the longer term, offsetting any short-term benefits.

Impact of proposals on flexibility

The impact of these charging proposals will be delays or withdrawal of investments in flexibility services leading to an associated reduction in potential energy savings for consumers and wider effects on the wider GB economy. This is already being evidenced by customers postponing or cancelling investments in demand side response and other flexible solutions. We have shared some examples of our experiences with customers in Appendix 3.

Given our concerns, we also commissioned a study to gather evidence from GB businesses on the impact of recent policy changes, including the TCR, and attitudes towards flexible energy. This was conducted through an online survey of 104 energy decision makers, across a range of sectors and company sizes, and a number of in-depth interviews. The study considered seven recent developments in energy policy (including TCR). The majority of respondents considered themselves to be familiar with flexible energy solutions; and most had adopted or were trialling flexible energy technologies. Appendix 2 provides more details on how we conducted the survey and specific findings.

Some key findings from the survey and interviews are:

- **A significant proportion of the respondent fear detrimental consequences** from recent policy changes, especially those in large firms and in compliance roles.
- **The <u>combined</u> impact of multiple regulatory changes is also adversely impacting confidence in flexible energy and on reaching carbon targets**.
- **The number of policy changes** were also an issue; several respondents advised that getting their boards to back investment in energy was difficult despite their desire to be greener.
- **The impact of charging reforms is one of the main concerns**
- **Around a third of the respondents say they are now delaying, deprioritising or no longer investing in flexible energy**

As responsible organisations, several have taken action to reduce consumption through investment in energy efficiency assets and/or tried to minimise their exposure by generating on site and/or providing demand response. The business cases for both these actions were predicated on energy costs savings, including non-commodity costs. The proposals from Ofgem adversely affect these business cases and organisations feel like they have been penalised for trying to take control and be more energy efficient. More details can be found in Appendix 3.

There is also a view that the rising non-commodity costs require further explanation and justification from Ofgem or BEIS. Many providers of flexible energy sources feel more extensive consultation is required and more is needed to show the link between individual polices and the overall energy strategy.

Coordinated implementation

Alongside the TCR, Ofgem is also progressing other projects that will have significant impacts on network charges. In particular, we would highlight the ENAP, a Significant Code Review (SCR) looking into network access arrangements and forward-looking charges; and the development of the framework for the RIIO-2 network price controls. To deliver the coherent approach described above, to create a positive investment environment, it is essential industry change is coordinated.

With regards to the new SCR, this is also considering network charging and so has a direct interaction with TCR. Fully cost-reflective network charges are necessary for the market to function efficiently. We do not believe that the forward-looking element of network charges is currently fully cost-reflective and is likely to be understated. Addressing this could go some way to mitigating some of the TCR impacts.

There is good reason to believe that the cost-reflective element of transmission charges, for example, is currently understated (and so residual charges are overstated). These are supported by academic studies. Therefore, these concerns with the locational element of the charges mean that concerns about the rising level of the residual should addressed together. This is explored in more detail in Appendix 4.

The review into forward-looking charges is likely to affect the structure of network charges (e.g. the balance between fixed and variable charges). This has the potential to offset some of the impact of the TCR and so would also change the modelled benefits of the TCR. The review into forward-looking charges is targeted to be implemented, for the most part, in April 2023. It makes sense to coordinate with the TCR and implement both in April 2023. This avoids unnecessary tariff disturbance, removes the risk of reducing cost-reflectivity in the short-term, and helps to avoid delays to the supply of flexibility. Coordinating the two reforms should also minimise any confusion for the end consumer.

Implementation from April 2023 would also allow implementation of the TCR to be coordinated with the RIIO-ED2 electricity distribution price control period. This is highly desirable as RIIO-ED2 is the key regulatory tool for Ofgem to improve overall arrangements to ensure the value of flexibility services can be fully realised by providers. Whilst we welcome the Energy Networks Association's December 2018 Flexibility Commitment, in which all of Britain's DNOs said they will openly test the market to compare flexibility service solutions against physical reinforcement, we believe this needs to be built into the RIIO-ED2 incentive framework. Local flexibility markets could provide key revenue streams to DSR projects.

Our experience with investing in local flexibility has also highlighted areas where the current methodology for electricity distribution needs updating:

- Data provision is key to the development of smart, flexible markets and must be measured as one of the main DNO and ESO deliverables. Network operators should be obliged to provide market participants with the data they need for efficient access to the market, including identifying where investment in new flexibility is needed.
- DNOs should be given incentives for making additional capacity available for connecting customers, as well as the way they deal with customers. The Incentive on Connections Engagement focusses on engagement with customers. This has been an effective tool and so we should now look beyond this. DNOs should also be given incentives to provide the connection capacity customers need in a timely manner (including through using flexibility services as an alternative to physical reinforcement).
- DNOs and the ESO should be required to demonstrate that whole system solutions outcomes have been considered, both in producing business plans, and delivering solutions.
- Price Control arrangements should provide an incentive for DNOs to move successful innovation projects into BAU, with a greater emphasis on cooperation and efficiency.

The value of coordination is also demonstrated by a comparison between the way Electricity Market Reform (EMR) was introduced and the approach being taken to delivering the current energy transition. A market framework approach was taken to EMR policy development, based on a White Paper, industry consultation and a legislative package of complementary measures. That allowed the market to prepare for the introduction of Contracts for Difference, the CM, carbon price floor, etc. and there was an understanding about the interactions between the different mechanisms.

Reform Preferences

For the reasons set out in more detail in our consultation answers in Appendix 1, we believe the following TCR approach would work best for consumers and investors alike:

Network Residual Charges:

- Residual allocated to segments based on net kWh
- Fixed charge recovery for smaller customer segments – Whole Current (WC) metered
- Capacity charge recovery for larger customer segments – Current Transformer (CT) metered
- Implementation in April 2023

Remaining non-locational embedded benefits:

- Transmission Generation Residual (TGR) removed from April 2021
- Partial BSUoS reform from April 2022

Any future change to treat BSUoS as a residual:

- No earlier than April 2023, subject to a firm regulatory stance provided in 2019

Responses to specific consultation questions

Our responses to your specific consultation questions can be found in Appendix 1. Please contact me if you would like to discuss any aspect of our response.

Yours sincerely,

Andy Manning
Director - Network Regulation and Forecasting
Centrica Regulatory Affairs, UK & Ireland

Appendix 1 - Answers to consultation questions

Q1 Do you agree that residual charges should be levied on final demand only?
Yes.

It is unclear what logic would be applied to decide on any split of allowed revenue recovery between different types of users (demand vs generation) and it is likely that any such split would be arbitrary and also open to further change.

It is preferable to decide upon who pays residual charges on a principled basis and we agree with Ofgem's assessment against the TCR principles. It is reasonable that generators should only face the marginal (cost-reflective) aspect of charges, and so not pay residual charges. This also reflects the current arrangements in distribution for the majority of generators.

However, to ensure it is consumers who are the beneficiaries of any reform, and to avoid windfall gains and losses for market participants, it is important that implementation timescales for changes to residual charge recovery are sufficient for industry parties to reflect in prices. In particular, we note there remains uncertainty over whether BSUoS will be treated as a residual charge in future. It is important that any move to treating BSUoS as a residual is subject to further consultation with sufficient implementation lead time to be reflected in prices.

Q2 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.
In principle we broadly agree with the high-level assessment of the options presented in Tables 6 and 7. However, this assessment implicitly requires an assumption that the current forward-looking element of network charges provide efficient signals and that parties are faced with otherwise identical market arrangements. This is a reasonable and potentially necessary assumption. However, we do not believe this is a safe assumption given forward looking charges and network access arrangements are subject to a separate significant code review. This means care should be taken when deciding upon actions arising from assessment against the principles and supports implementing changes at the same time as any changes that arise from the Electricity Network Access Project (ENAP).

We also make the following observations:

Reducing harmful distortions:
- Whilst both leading options score well against this principle, this conclusion relies on a belief that they reduce distortions to efficient price signals. As set out above, we do not consider this to be a safe assumption. For instance, in practice it is likely that distortions in residual recovery are counteracting flaws in current forward-looking charges and differences in access arrangements e.g. connection charging boundary or firmness of access rights. As explored in more detail in Appendix 4, there is good reason to believe that the cost-reflective element of transmission charges is currently understated.

Proportionality and Practical considerations:

- The Fixed charge approach will not work for unmetered supplies, where a single MPAN can represent anything from a couple of exit points to many thousand exit points. We suggest that for unmetered supplies, the residual continues to be recovered via kWh to overcome this issue.

Distributional impacts:

- We disagree with the ‘green’ categorisation for Ofgem’s Agreed Capacity approach. We believe there would be a significant detrimental impact on small non-domestic and microbusiness customers who would see huge increases in network charges, driven by the questionable assumptions that have been adopted for deemed capacities. Frontier’s User Group information shows that the median peak demand for these customers ranges from 4.73 kWh to 6.11 kWh (equivalent to 10kVA – 13kVA assuming a 0.95 power factor). It therefore seems inappropriate to use a deemed capacity of 55kVA for these customers. We estimate this would result in this customer segment paying c. 40% of total residual costs, despite representing only c. 15% of total volumes. Such an approach would create a perverse incentive for these customers to install a CT meter to enable them to agree a much lower capacity with the DNO.
- We also disagree with the ‘green’ categorisation for Ofgem’s Fixed charge approach. Whilst the distributional effects are reduced by the proposed approach to segmentation, a fixed charge approach will nonetheless remain regressive within a segment. This is most apparent for larger customers (CT Metered) with agreed Maximum Import Capacities (MICs). Below we set out the range of MICs for our portfolio for each of the CDCM HH tariffs. Under the fixed charge approach, within these segments, each customer would receive the same charge which will have a huge distributional impact compared to the status quo:

CDCM Tariff	MIC range	P10/P90 range	Approx. Fixed Residual charge per customer
LV HH	1kVA – 1600kVA	30kVA – 180kVa	£4,000/yr
LVS HH	7kVA – 1100kVA	30kVA – 500kVA	£11,000/yr
HV HH	5kVA – 37000kVA	100kVA – 2300kVA	£40,000/yr

Fairness:

- For the fixed charge approach, we do not think it is appropriate to assume that all users within a segment are alike. Whilst the distributional effects are reduced by the proposed approach to segmentation, a fixed charge approach will nonetheless remain regressive within a segment. We are particularly concerned about the lowest consuming households which could see increases of up to £22, and the smaller users within the larger customer segments which could see huge increases in residual allocation.
- User characteristics within segments can vary significantly, and this will be particularly apparent for larger users (CT metered), particularly at higher voltage levels. We are concerned that a fixed charge approach will result in an unequitable allocation of residual to the smaller customers within these broad segments, and will also lead to customers of similar size being allocated significantly different residual costs because they are connected at different voltages. For instance, over 20% of our LV HH portfolio (CT metered) have an agreed capacity of less than 50kVA, yet we estimate they will pay c. £3000/yr more in residual cost compared to equivalent customers who are WC metered. We also note that due to their small demand, they could simply change their meter to WC to switch segments reducing their costs. This provides an incentive that is not economically justified. This also applies to customers of

similar size connected at different voltage levels e.g. a smaller HV connected customer could reduce charges by c. £35k/yr by disconnecting their HV connection and paying for an LV connection instead.

- We consider a hybrid of Ofgem's two leading options would score higher in the Fairness assessment:
  - A net kWh approach to **residual allocation** to segments
  - A fixed charge approach to **residual recovery** for smaller WC-metered customers
  - A capacity charge approach to **residual recovery** for larger CT-metered customers

Our proposed hybrid approach is an improvement on Ofgem's preferred option which uses agreed capacity as a way to further segment larger users to improve equitability and reduce boundary effects. Since it maintains a net volume allocation/fixed charge recovery for smaller customers, it also avoids the problems associated with deeming capacity.

Q3 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 agree that the current approach should be maintained, although we don't agree with the simplified description of the current approach. It is reasonable to say that distribution customers pay residual costs for both distribution and transmission, whilst transmission customers only pay residual costs for transmission. However, within distribution, customers currently contribute equally to residual costs regardless of their voltage of connection and so we don't think it accurate to say that customers do not pay residual costs for lower voltage levels.

Q4 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.

The proposed approach of allocating the residual to segments on the basis of net kWh is sensible and helps to promote fairness at an aggregate segment level.

However, within some segments there is likely to be a lack of equity under the proposed fixed charge approach. This will be particularly the case where segments contain a broad range of customers in terms of size and characteristics. We believe that for larger customer segments (CT-metered), particularly at higher voltage levels, a fixed charge approach will not result in an equitable allocation of residual costs. This is because under the proposed net KWh approach to segmental allocation we expect that high usage, higher load factor segments will pick up a greater share of residual cost in aggregate, but it will be the smaller customers within these segments that will be most adversely affected due to the application of a single fixed charge.

As set out above, we recommend a hybrid of Ofgem's two leading options would overcome this concern:

- A net kWh approach to residual allocation to segments
- A fixed charge approach to residual recovery for smaller customers (WC metered)
- A capacity charge approach to residual recovery for larger customers (CT metered)

Our proposed hybrid approach is an improvement on Ofgem's preferred option, improving equity by using agreed capacity to further segment larger users. It also avoids the problems associated with deeming capacity for smaller users by maintaining a fixed charge recovery.

Q5 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)?

In principle, and where markets for flexible services are established, similar parties should pay similar residual charges and behind-the-meter generation should not be excluded from that charge.

However, current residual arrangements have acted as support for methods of providing flexibility behind the customer meter and it is important to recognise the detrimental impact the reform to residual charges, in isolation, will have on the growth of local flexibility. We commissioned a study to gather evidence from GB businesses on the impact of recent policy changes, including the TCR, and attitudes towards flexible energy. This is summarised in Appendix 3.

Removing current distortions and barriers should allow markets for flexibility to flourish. However, this needs careful coordination to avoid removing current revenue streams from flexibility service providers before they can access future alternatives. This includes more cost-reflective forward-looking charges and improved access arrangements, to be delivered as part of the ENAP by 2023, as well as reforms to the next electricity distribution price control (RIIO-ED2). As explored in more detail in Appendix 4, there is good reason to believe that the cost-reflective element of transmission charges is currently understated.

To avoid the risk of stalling the development of local flexibility, these residual reforms should be implemented alongside the other changes necessary, from April 2023, to align to the RIIO-ED2 price control.

Q6 Do you know of any reasons why the expected consumer benefits from our leading options might not materialise?

Whilst we agree that in the long term there will be consumer benefits in charging arrangements which reduce distortions from an efficient cost signal, we believe there are a number of reasons why the expected consumer benefits presented in the consultation may not materialise:

Value of local flexibility/lack of network impact: Ofgem's modelling appears to show that over the whole system, the flexibility lost at local level will be replaced with transmission-connected flexibility. These are not equivalent - local flexibility needs cannot be accommodated by flexibility at transmission level and will result in more local reinforcement costs. A significant portion of the value of this local flexibility is driven by reduced/deferred network investment. Whilst we understand the reasoning given for omitting the impact on network costs, we believe this is likely to cause the consumer benefits to be overstated. A reduction in electrical losses can also be expected, from providing flexibility more locally, which we do not believe is captured by Ofgem's analysis. Again, this is likely to cause the consumer benefits to be overstated.

More generally, the analysis does not seem to fully capture the value of local flexibility. Energy flexibility and smart networks have the potential to provide significant value to the UK economy, save money for consumers and contribute to decarbonisation.

Research commissioned by Centrica found that if just three sectors of the UK economy – healthcare, industry and hospitality and leisure – adopted flexible distributed energy solutions they could achieve almost £1bn of savings on annual energy spend, while delivering an £18.5bn boost to the country's overall economic growth and creating 260,000 new jobs[5]. Distributed energy solutions in these three sectors could also lead to annual emissions savings of 7.2 MtCO2e, equivalent to 11 per cent of the three sectors' current carbon footprint.[6] By 2030 that would represent a three per cent reduction of the UK's entire Carbon Budget.

This is consistent with the findings of other organisations. For example, analysis by Imperial College London with the Carbon Trust for Government suggested the UK could save £17-40bn across the electricity system from now to 2050 by deploying flexibility technologies. The net benefits (after costs) are predicted to be in the range of £1.4 to £2.4bn per year by 2030.[7] The Association of Distributed Energy (ADE) calculates that 16 percent of the UK's peak electricity requirement – or 9.8 GW – could be provided just by businesses being flexible in their energy demand, which could save UK energy consumers £600m by 2020 and £2.3bn by 2035[8].

Changes in balancing costs/ancillary services costs:
The analysis of consumer benefits does not appear to have factored in any impact for the change in BSUoS charges that will result from the change in balancing costs/ancillary services costs associated with the change in generation mix. However, the corresponding change ancillary services revenues does appear to have been in factored in to the Capacity Market bids and costs. We believe BSUoS charges are likely to increase and so consumer benefits will be overstated.

Impact on Energy Efficiency Investment:
The Frontier report acknowledges that there will be an impact on energy efficiency investment, and this is supported by our own survey results. Reduced investment in energy efficiency investment will almost certainly lead to higher system costs as underlying demand will increase, leading to higher network reinforcement costs, losses and Capacity Market requirements. A similar effect can be expected due to the increase in demand caused by the underlying demand price response to reduced peak charges i.e. general price elasticity response rather than investment response.

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[5] Centrica Business Solutions report '*Distributed Energy: Powering Britain's Economic Future*' November 2017

[6] Centrica Business Solutions report '*Distributed Energy: Powering Sustainability*' October 2018

[7] Imperial College London. Carbon Trust '*An analysis of electricity system flexibility for Great Britain*' November 2016

[8] Association of Distributed Energy report '*Flexibility on demand: Giving customers control to secure our electricity system*' July 2016

Inefficiency of current forward-looking charges:
The consumer benefits presented are premised on the theory that by reducing the distortionary impact of the current basis of residual charging, the efficiency of the system will be improved, thereby providing consumer benefits. This is reinforced in Annex 3 of the minded-to decision (Academic research and international comparisons):

> *"Economic efficiency is maximised when residual charges are recovered in a way which minimises the distortion to users' efficient behaviour.* ***Efficient behaviour means the electricity consumption and investment decisions that users would make if they were only charged the marginal cost of increases in their electricity use****. This concept is firmly planted in the principle we have applied in this review of reducing harmful distortions.*"

Fundamentally this theory requires a belief that the current basis of forward-looking charging provides efficient cost signals. This is a reasonable and probably necessary assumption to conduct the impact assessment upon. However, given that forward-looking charging and network access arrangements are the subject of a separate SCR, there must be doubt as to the robustness of this assumption. In practice it may be that distortions in residual recovery are counteracting flaws in current forward-looking charges and differences in access arrangements.

Therefore, whilst we agree that in the long term there will be consumer benefits in charging arrangements which reduce distortions from an efficient cost signal, care should be taken when deciding upon actions arising from this assessment. This supports implementing changes at the same time as any changes that arise from the ENAP. To do otherwise could result in consumers paying more because residual reform would be implemented ahead of the other reforms, leaving inefficient access arrangements and forward-looking charges to drive inefficient behaviour and decisions in the interim period, including the stalling of investment in flexibility. As explored in more detail in Appendix 4, there is good reason to believe that the cost-reflective element of transmission charges is currently understated.

Interaction with EU cap (TGR):
The wider system modelling has been assessed after removing the TGR (as set out in paragraph 5.12). However, Ofgem's policy intent of removing the TGR (setting it to zero), cannot be assumed whilst TNUoS arrangements for Generators continue to be capped by EU regulation 838/2010. Any negative correction mechanism required to ensure compliance with the regulation, regardless of whether or not it is labelled a 'residual', will distort the efficiency of investment decisions.

Our analysis of National Grid's latest Five-Year forecast, set out below, shows that even when all local charges are assumed to be captured by the connection exclusion, in line with CMP261, there will still be a requirement for a residual type correction – reaching £2.81/kW in 2023/24. This credit would be higher than set out below if some local charges are deemed not to be part of the connection exclusion. The credit would also be higher if, as set out in Ofgem's impact assessment, there is an increase in flexible generation plant connecting at transmission level as a result of these reforms. The distortion could also develop into a death spiral similar to that observed by the Triad benefit for embedded export i.e. the more generation connecting to transmission to take advantage of the credit, the higher the credit will become.

	Component	Source	2019/20	2020/21	2021/22	2022/23	2023/24
Generation Residual							
R_G	No Reform: Generator residual tariff (National Grid Forecast) (£/kW)	Table 27	-2.34	-4.37	-5.60	-8.10	-10.58
Generation Correction Mechanism to comply with EU Regualtion 838/2010 (post CMP261 & TCR)							
GMAR	Revenue to be recovered from generation (£m) (Table 24)	Table 24	403.5	392.5	382.2	372.4	362.1
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	Table 27	322.2	362.7	391.4	477.7	597.6
O	Revenue recovered from offshore local tariffs (£m)	Table 27	244.0	311.2	337.0	426.9	495.8
L_G	Revenue recovered from onshore local substation tariffs (£m)	Table 27	20.7	19.8	20.2	20.4	24.2
S_G	Revenue recovered from onshore local circuit tariffs (£m)	Table 27	18.5	19.4	45.7	55.9	131.2
$CMP261_G$	Total Generation Revenue Recovered less all local tariffs i.e. Z_G only (£m)	Table 27	322.2	362.7	391.4	477.7	597.6
$MIN(0, CMP261_G - GMAR)$	Correction Required for EU Cap compliance (£m)	Calc	0.0	0.0	-9.2	-105.3	-235.5
B_G	Generator charging base (GW)	Table 27	75.0	73.3	73.6	75.2	83.8
R_G	Post Reform: Generator Correction tariff (£/kW)	Calc	0.00	0.00	-0.12	-1.40	-2.81

We agree that negative residuals are not conducive to the effective functioning of the wholesale market and create a distortion between transmission and distribution connected generation. However, the system and consumer impacts of reform should be assessed including the current constraint of the EU Cap.

Lack of clarity regarding BSUoS arrangements, creating additional market risk:
Unlike the proposed treatment of the TGR, where Ofgem has been clear about its desire and intention to remove negative residuals since 2017, at no point prior to this minded-to decision have Ofgem made any specific proposals to change BSUoS charging arrangements, over than to say they would keep it under review. The proposed BSUoS reform could therefore be viewed as a surprise by market participants.

The minded-to decision has also significantly increased the uncertainty surrounding BSUoS arrangements. Ofgem's specific proposals being consulted on could result in BSUoS rates reducing by between c. 10% (Partial Reform) and c. 20% (Full Reform) in either April 2020 or April 2021.

However, this is subject to the conclusions of the BSUoS Task Force. If the Task force concludes that BSUoS should be treated as a cost recovery, then this could ultimately result in BSUoS becoming a demand only charge, in line with the TCR principles, which we estimate would result in BSUoS rates increasing by c. 60% (with an unknown implementation date).

We consider there has been, and continues to be, a lack of regulatory clarity provided on BSUoS reform. Reforms can cost consumers more in the short term if they are not well signalled, with implementation timescales sufficient to allow parties to reflect in prices. At present, it is difficult for both suppliers and generators to predict the expected BSUoS arrangements resulting from these reforms, which could lead to higher risk premiums in prices and in investment cases.

We recommend that any reform of BSUoS charging arrangements is implemented 3 years after a firm regulatory position is provided by Ofgem. Therefore, for the BSUoS embedded benefit reform, this would be April 2022, given the clear signal provided in this consultation. However, for any BSUoS residual reform, we would not expect any firm position to be signalled until later in 2019, after further consultation, and therefore implementation would be appropriate from April 2023 (in line with our view of when wider T&D residual reform should occur).

Uncertainty in implementation dates could cost consumers more in the short term:
We have previously supported reform of the TGR from 2020 on the basis that Ofgem has signalled this intent for a number of years. However, the lack of a firm preference on implementation date

in this minded-to decision has now created significant uncertainty, which could adversely affect consumers.

It would be risky for Suppliers to assume TGR reform (significantly reduced TNUoS demand charges) from April 2020, when April 2021 is an equally probable implementation date. Similarly, it is difficult for Generators to assume the receipt of a TGR credit in 2020, when Ofgem are proposing to remove it from that date.

The result is that consumers could potentially pay residual costs twice in 2020 if Suppliers and Generators take a prudent approach to reform assumption in price setting. We recommend Ofgem rule out an April 2020 implementation date for the TGR reform and BSUoS embedded benefit reform as soon as possible, and preferably ahead of its final TCR decision.

Q7 Do you agree that our leading options will be more practical to implement than other options?
We agree the leading options (Fixed charges and Capacity charges) are more practical to implement than the other options presented. The leading options utilise existing industry mechanisms and, as such, will require fewer modifications to industry arrangements and systems. As discussed above, we recommend a hybrid approach comprising fixed charges for smaller WC-metered customers and capacity charges for larger CT-metered customers. Capacity-based residual charging for larger customers will mitigate concerns about fairness because of the range of size of customers within these groups.

It may be more practical to segment HV- and LV-connected customers according to the Common Distribution Charging Methodology (CDCM) tariff groups. Further, in some DNO areas, customers within a single CDCM tariff group have been assigned different LLFCs. In those instances, segmenting customers according to LLFCs could result in different residual costs being allocated to customers within the same CDCM tariff group, requiring additional CDCM tariffs.

From a systems perspective, it may also be more practical for both the transmission and distribution residual costs to be recovered in a single charge. This could be achieved by the ESO charging DNOs directly for the transmission operators' residual costs, with each DNO passing this through to suppliers on top of its own residual costs, in a similar manner to how exit charges work currently. Since DNOs and industry participants already have systems that cater for DNO fixed charges and agreed capacity charges, this would largely remove the need for system changes to cater for the recovery of the Transmission residual. Such an approach would require these costs to be treated as a pass-through cost in DNOs price control allowances which could be factored into the RIIO-ED2 arrangements.

Q8 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.
It may be more practical to segment HV- and LV-connected customers according to the CDCM tariff groups. Further, in some DNO areas, customers within a single CDCM tariff group have been assigned different LLFCs. In those instances, segmenting customers according to LLFCs

could result in different residual costs being allocated to customers within the same CDCM tariff group, requiring additional CDCM tariffs.

If Ofgem were to take forward the agreed capacity-based residual charging approach, we recommend that the approach to banding reflects network planning principles, because of the relationship between the historic level of network investment that was needed and the residuals. For those customers without an agreed capacity, we recommend deeming is based on After Diversity Maximum Demand (ADMD), which is used to determine the level of network investment needed. The current proposed basis of deeming would have a significant detrimental impact on small non-domestic and microbusiness customers who have been deemed agreed capacities of 55kVA, when Frontier's User Group information suggests that values between 10kVA – 13kVA would be adequate for the median peak demand of these customers.

The Frontier analysis equates the electrical maximum connection capacity for WC metered customers (55kVA) with the agreed Maximum Import Capacity for CT-metered customers. These are not the same, as demonstrated by the range of MICs for our portfolio of LV HH customers set out in answer to question 2. Our customer MICs range from 1kVA – 1600kVA, yet the electrical maximum connection capacity is likely to be the same for most of them.

As set out earlier, our preference is for a hybrid of Ofgem's two leading options which would overcome the issues of deeming capacities for small customers and ensuring equity within segments for large customers:

- A net kWh approach to residual allocation to segments
- A fixed charge approach to residual recovery for smaller WC-metered customers
- A capacity charge approach to residual recovery for larger CT-metered customers

Q9 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?

It may be more practical to segment HV- and LV-connected customers according to the CDCM tariff groups. Further, in some DNO areas, customers within a single CDCM tariff group have been assigned different LLFCs. In those instances, segmenting customers according to LLFCs could result in different residual costs being allocated to customers within the same CDCM tariff group, requiring additional CDCM tariffs.

Q10 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.

Distributional Modelling:

The User groups used for the distribution modelling do not sufficiently capture the distributional impacts of the changes. For instance, there are no LV HH or LV-substation HH customer user groups, despite these groups representing a significant portion of overall demand. This is concerning because there is a large range of size of customers within these segments and so the distributional effects will be significant.

We also note that there is only one HV User Group, but this User is assumed to have a 2000 kVA agreed capacity. The average HV customer across GB has a c. 1000 kVA agreed capacity and so the baseline residual bill in the analysis (kWh/Triad based) is based on a customer that is twice as large as the average customer in the segment. This means that when the baseline residual is compared to fixed charge residual, it will not reflect the expected impact on the 'average' customer in the segment.

As has been recognised in the consultation, the EDCM residual under the fixed charge approach is likely to be significantly understated due to the inclusion of generation imports in the denominator of the customer count.

System Modelling:
Specifically, we are concerned that the impact on network costs, and losses, is excluded from the modelling as well as the impact of reduced investment in energy efficiency. A significant portion of the value of local flexibility is driven by reduced/deferred network investment. Whilst we understand the reasoning given for omitting the impact on network costs, we believe this is likely to cause the system benefits to be overstated.

More generally, we agree with Frontier's view on how the modelling should be interpreted:

> *'…we reiterate our previously expressed view that quantitative modelling should not be the sole (or in many cases even principal) basis for determining whether particular modifications to a charging regime are appropriate, and that a qualitative assessment against clear criteria is of critical importance.'*

We believe there are clear benefits to coordinating implementation with the ENAP and RIIO-ED2, and so implementing residual reform from April 2023. This will avoid the risk of stalling the development of local flexibility. We recognise that the consumer benefit is reduced compared to the Ofgem implementation options but do not believe that this should be the sole, or principal, basis for deciding the implementation. This is supported by the observations regarding the modelling made in our answers to questions 6 and 10.

We also note that the modelling shows that system costs reduce with a 3-year delay in implementation (April 2023) compared to both of Ofgem's implementation options. We do not seek to argue that this is justification for delaying to April 2023 but to illustrate the quantitative modelling should not be used to determine when implementation should occur.

Q11 Do you agree with our proposed approach to the reform of the remaining non-locational Embedded Benefits?
We broadly agree that the remaining relevant non-locational Embedded Benefits should be reformed but we recommend different timescales and coordinated implementation.

Previously, Ofgem signalled implementing TGR reform in 2020, which we supported. Ofgem is now consulting on implementation in either 2020 or 2021 without stating a firm preference. This has created significant uncertainty for market participants and a decision in mid-2019 will be too late to allow market participants to fully reflect reforms in commercial arrangements for 2020. We recommend Ofgem rule out an April 2020 implementation date for the TGR reform ahead of its final TCR decision to mitigate against this outcome.

We support the ‘Partial’ reform option for BSUoS. We consider there has been, and continues to be, a lack of regulatory clarity provided on BSUoS reform. However, given that is it probable that at least some BSUoS costs will be classified as a cost recovery following the Task Force conclusion (e.g. the ESO’s internal costs), it is inconsistent with the TGR principle of recovering residual from demand to move to ‘Full’ reform. It would also be impractical as this will cause multiple step changes in charges, systems and processes.

Q12 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. The other remaining embedded benefits are insignificant and are unlikely to be causing market distortions, whilst changing them would incur system costs across the industry. They would seem to clearly fail the principle of proportionality and practical considerations.

Q13 Are there any reasons we have not included that mean that the remaining Embedded Benefits should be maintained?

If the Task Force recommends that all or most of BSUoS should be treated as a cost recovery, then there will need to be further consideration and consultation on whether and how the TCR principles should be applied to BSUoS. Therefore, any proposed move to BSUoS becoming a fully or predominately demand only charge should be subject to further consideration and consultation.

Such a scenario would create an interim period where reform of the BSUoS embedded benefit occurs before BSUoS residual reform, and therefore it seems logical that the Partial BSUoS Reform option is more sensible for the embedded benefit reform. It would make little sense to introduce a charge to embedded generators, with the associated industry system and process costs, only to remove it again shortly after.

Q14 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.

Transmission and Distribution Residual Charges:

We recommend an **April 2023 implementation**. The largest impacts of these reforms will be the significant redistribution of costs imposed on all customers in general, and the negative impact on flexible behind the meter technologies.

- **Redistribution of costs:** We are concerned about the lowest consuming domestic households and the smaller customers captured within the larger customer segments. We believe aligning implementation to the start of RIIO-ED2 would help to mitigate the impact on these customers given that Ofgem expect to see significant reductions in allowed revenues overall as a result of the next set of RIIO price controls.

- **Flexible behind the meter technologies:** Removing current distortions and barriers should allow markets for flexibility to flourish. However, this needs careful coordination to avoid removing current revenue streams from flexibility service providers before they can access future alternatives. This includes more cost-reflective forward-looking charges and improved access arrangements, to be delivered as part of the ENAP by 2023, as well as reforms to the next electricity distribution price control, which will also apply from 2023. To avoid the risk of stalling the development of local flexibility, these residual reforms should be implemented alongside these other necessary changes from April 2023.

Non-locational embedded benefits:

- **TGR:** We recommend an **April 2021 implementation.** Ofgem has signalled its intent to remove the TGR from April 2020 for a number of years. However, whilst we have previously supported this, the lack of a firm preference on implementation date in this minded-to decision has created too much uncertainty for us to continue to support this position. It is difficult for Suppliers to assume TGR reform (significantly reduced TNUoS demand charges) from April 2020 and it is similarly difficult for Generators to assume the receipt of a TGR credit in 2020. The result of poorly implemented reform is that consumers could potentially pay residual costs twice in 2020 if Suppliers and Generators take a prudent approach to reform assumption. We recommend Ofgem rule out an April 2020 implementation date for the TGR reform ahead of its final TCR decision to mitigate against this outcome.
- **BSUoS embedded benefit:** We recommend **Partial Reform** and an **April 2022 implementation**. We consider there has been, and continues to be, a lack of regulatory clarity provided about reform to BSUoS charging arrangements. Given the inclusion of the proposed BSUoS embedded benefit reform in this consultation could be viewed as a surprise by market participants, we recommend an April 2022 implementation. We do not see an issue with de-coupling the TGR reform (2021) and BSUoS embedded benefit reform (2022) as these dates simply reflect reasonable implementation timescales from the point Ofgem provided a firm regulatory stance. As with the TGR reform, we recommend Ofgem rule out an April 2020 implementation date ahead of its final TCR decision.
- **BSUoS residual reform:** We recommend an **April 2023 implementation** for any **residual** reform of BSUoS arrangements. Whilst it is not within the scope of this consultation, we recommend that if, following the Task Force recommendations, and appropriate consultation, Ofgem decide that most or all of BSUoS should be a cost recovery charge, then an April 2023 implementation should allow sufficient time to be adequately reflected in commercial contracts.

Q15 Do you agree with our minded to decision set out? If not please state your reasoning and provide evidence to support your answer.

We do not agree with the minded-to decision for the reasons set out in our responses to previous questions. We believe the following approach would work best for consumers and investors alike.

Network Residual Charges:

- Residual allocated to segments based on net kWh
- Fixed charge recovery for smaller WC-metered customers
- Capacity charge recovery for larger CT-metered customers

- Implementation in April 2023

Remaining non-locational embedded benefits:

- TGR removed from April 2021
- Partial BSUoS reform from April 2022

Any future change to treat BSUoS as a residual:

- No earlier than April 2023, subject to a firm regulatory stance provided in 2019

Q16 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.

The Fixed charge approach will not work for unmetered supplies, where a single meter point (MPAN) can represent anything from a couple of exit points to many thousand exit points. We suggest that for unmetered supplies, the residual continues to be recovered via kWh to overcome this issue.

From a systems perspective, it may be simplest if both the transmission and distribution residual costs were recovered in a single charge. We suggest that this could be achieved by the ESO charging DNOs directly for the transmission operators' residual costs and each DNO passing this through to suppliers along with its own residual costs, in a similar manner to how exit charges work currently. Since DNOs and industry participants already have systems that cater for DNO fixed charges (or agreed capacity charges, or a combination of the two), this would largely remove the need for system changes to cater for the recovery of the Transmission residual. Such an approach would require these costs to be treated as a pass-through cost in DNOs price control allowances which could be factored into the RIIO-ED2 arrangements.

Appendix 2 - Research Approach and Selection Criteria Survey

Online survey of businesses in the UK, all companies with more than 500 staff and £100k+ energy spend:

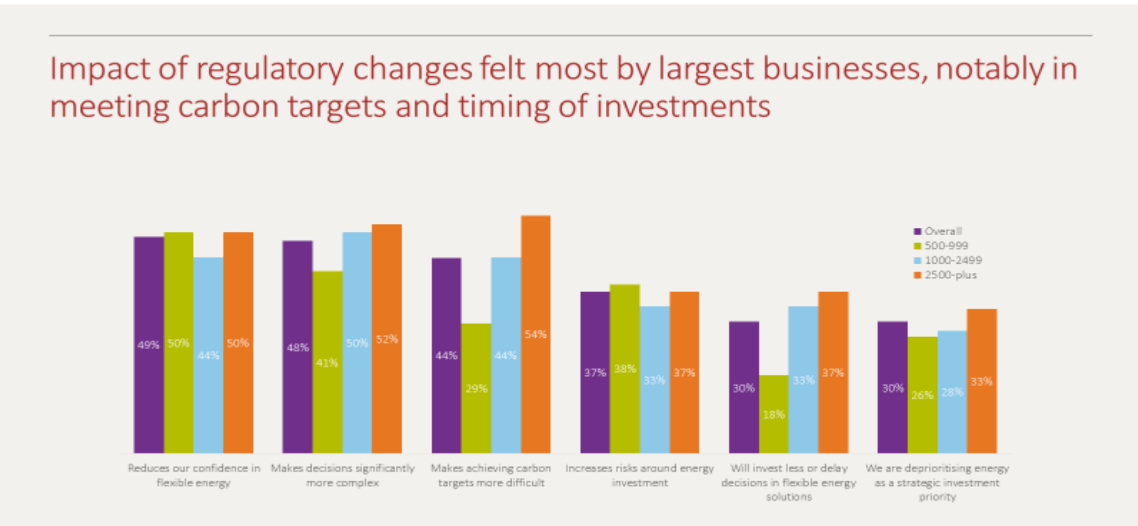
- Total sample of N=104, survey completed during end-December / early-January 2019
- Respondents had to be the decision maker or to have significant influence over firms' energy solutions
- Majority of respondents were senior decision-makers but not specifically energy professionals
- All companies surveyed had to have at least trialled one or more flexible energy solutions
- Most respondents considered themselves to be familiar with flexible energy solutions

Respondents asked to comment on seven developments in national energy regulatory policy:

- Tightening of air quality regulations (MCPD and its UK implementation by DEFRA/EA)
- Suspension of the Capacity Market:
- Network charging reforms removing the ability to avoid network and BSUOS charges
- Impact of carbon price on energy prices – and uncertainty around the carbon price trajectory in the UK and the EU
- Closure of Feed-in tariffs for solar generation from March 2019
- Increases in rate of climate-change levy paid by gas generators:
- Removal of enhanced capital allowances for CHP.

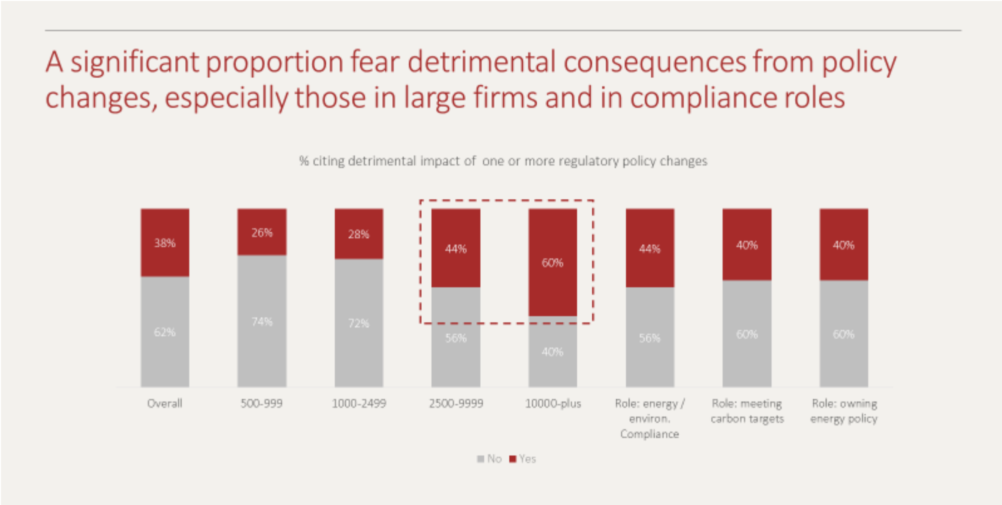
Around 90% were highly (47-54%) or somewhat familiar (35-44%) with all of the policies and there was a similar response for the relevance of each policy to their company.

The impacts were largely consistent across all companies, although the largest companies tended to feel them more, perhaps due to more stringent environmental requirements on larger users.



Summary of findings:

- **A significant proportion of the respondent fear detrimental consequences** from recent policy changes, especially those in large firms and in compliance roles. 44% of medium sized companies and 60% of large companies cited detrimental impacts from one or more recent policy changes. (Chart 1)

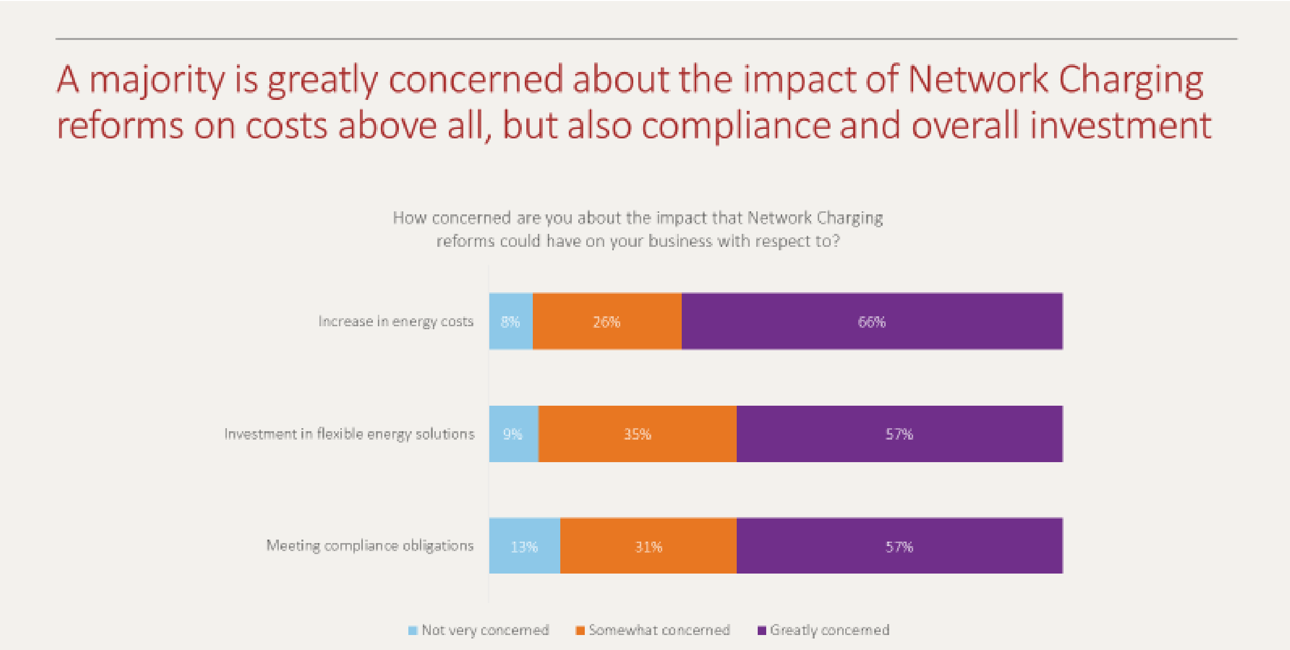


- **The <u>combined</u> impact of multiple regulatory changes is also adversely impacting confidence in flexible energy and on reaching carbon targets**. The main reasons given were:
  - the impact on investor certainty because of the number of policy changes;
  - concern that the investments can be undermined by future policy changes e.g. saving from energy efficiency measures reduced by changes in T&D charging
  - the complexity of the different policies and the resources needed to understand the impact of legislation and compliance;
  - too much "tinkering" and no long-term commitment to policy ("the goal posts keep shifting");
  - and no clear roadmap.

- **The number of policy changes** were also an issue; several respondents advised that getting their boards to back investment in energy was difficult despite their desire to be greener. The number of recent policy changes had further undermined their ability to make successful investment cases.

  The combined impact of multiple regulatory changes is felt most keenly by those respondents most familiar with the policy changes. Around a half said investment confidence had been impacted and / or decisions were now more complex. Around 40% are worried we won't make our carbon targets.

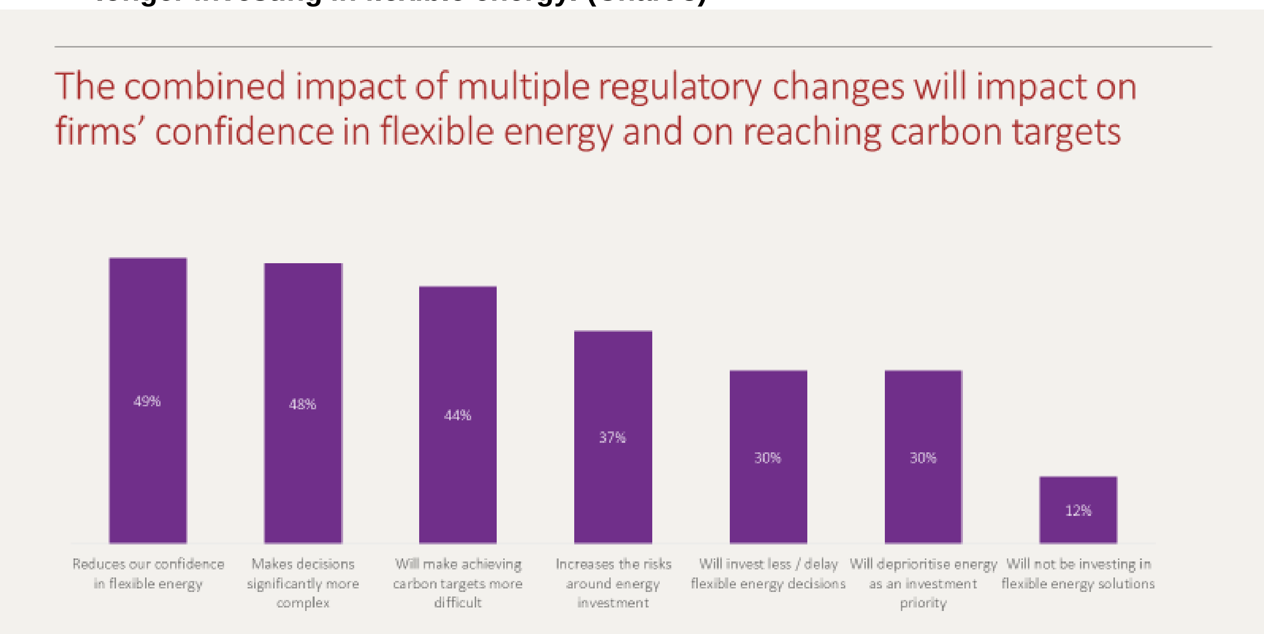
- **The impact of charging reforms is one of the main concerns** (Chart 2). Several companies flagged that they have major concerns around the increases in non-commodity costs and T&D costs in particular. They see value in being able to take more control of these costs and to manage their exposure.



- As responsible organisations, several have taken action to reduce consumption through investment in energy efficiency assets and/or tried to minimise their exposure by generating on site and/or providing demand response. The business cases for both these actions were predicated on energy costs savings, including non-commodity costs. The proposals from Ofgem adversely affect these business cases and organisations feel like they have been penalised for trying to take control and be more energy efficient.

- There is also a view that the rising non-commodity costs require further explanation and justification from Ofgem or BEIS. Many providers of flexible energy sources feel more extensive consultation is required and more is needed to show the link between individual polices and the overall energy strategy.

- **Around a third of the respondents say they are now delaying, deprioritising or no longer investing in flexible energy. (Chart 3)**



Appendix 3- Qualitative Interviews

Headlines from detailed conversations with six energy managers representing in six major energy users.

B.1 Interview with a major Water Company engaged in flexibility

- Sees local air emissions control as the right thing to do, but **implementation is too complex**
- Considers **overall complexity of policy regulations** far too great – even for a business like theirs.
- Environment Agency has been unclear on what types of use for each type of generator will be compliant by a certain date. More clarity is needed.
- Believes that **loss of incentives for renewables** will hit their flexible energy investment. "We will not decarbonise as quickly as we want."
- **Reducing emphasis** on DSR activity; invested significantly in DSR / FR 18 months ago, but the value of their investments, and the associated uncertainty, is much different than what they thought.
- As a business, can respond to what the govt. wants, (e.g. responding to Triad charges), but its not clear exactly what they want or is needed; they believe **government is not making this clear enough**
- In summary, feels they as a business would be able to **do much more with flexible energy** if only the government provided clear guidance and incentives. Sees many of the changes as 'blunt instruments'.

B.2 Interview with a major Supermarket Chain

- Believes suspension of the capacity market is positive, as benefits currently accrue to generators, where he wants to see more adoption of DSR.
- **Feels that CHPs are still viable but increases in CCL may limit that**
- Use DSR on 8-12% of estate but are limited **in their ability to extend this** due to the limitations of grid infrastructure
- Loss of **solar feed-in makes this unviable**, though he understands the theoretical position that solar is now more efficient and does not require large subsidies
- Concerned over **increases in transmission and distribution charges** – with little control over these
- Believes manufacturers **may be hit massively by changes to Triads and distribution charges** – The supermarket chain may need to change suppliers as a result of this (towards larger manufacturers that can comply)
- Accepts that the supermarket chain has the resources to manage this area, but is **concerned for smaller firms which are unable to cope** with / understand / comply with regulations, and are hence discouraged from energy efficiency
- Sees govt. having to be **more consistent in policy**, **not punishing companies** by changing the goalposts, as it is in the government's interest to incentivise the right behaviours

B.3 Interview with a national Leisure Company

- Have reduced carbon footprint by a third and saved £400k p.a. as result
- Despite being clearly expert, respondent is **uncertain or unclear** about the impact of a number of the policy changes
- **Spike in non-commodity costs is a major concern**: from 60:40 to 40:60 over the past six years.
- Concerned that sum total of changes will be a **large and unavoidable increase in energy costs**
- Feels that they are being **penalised for investing in CHPs** (they have over 20 now) due to CCL levy, although removal of ECA is not going to impact (as they have limited opportunity to bring in new CHPs)
- A major gripe is **lack of transparency** in how non-commodity and other charges (e.g. CRC, AAHEDC) are being used, currently sees little or no evidence of what government / energy sector is doing
- Wants to use DSR but currently this is 'almost impossible' due to the nature of their business

- **Very frustrated with DNOs** which are regional monopolies, are **unaccountable and provide poor service**

B.4 Interview with a leading Livestock Producer

- Trying to drive uptake of flexible energy (esp. battery) for resilience and to avoid Triad charges / adopt DSR but cost of batteries is prohibitive (upwards of £1m for a 1MW unit). **Too many confusing regulations impact on decision-making**
- **Struggling to get board to back investment in energy** even though there is desire to become greener
- Concerned about **steep rises in distribution and transmission charges**.
- Passionate that decarbonisation needs to happen now, but **government action is delaying / stifling investment**
- Feels that the carbon price needs to increase to drive this investment
- Quite angry with **government's lack of clear guidance** / direction to business
- Believes energy suppliers are not talking in ways that their board understand – too technical
- **Brexit is adding to uncertainty**, not least in light of CCL exemptions for energy-intensive industries
- The banking sector will need to step in to **drive investment in low-carbon** if govt. fails to do so

B.5 Interview with a leading Insurance Company

- **Limited adoption of flexible energy** due to ownership constraints (mainly leasing), and hence difficult ROI
- Changes to CRC – towards CCL - **will cause greater uncertainty**, and charges will be hidden in all bills
- **In favour of tightening air quality regulations**; agrees with scrapping of feed-in tariffs (previously 'crazy' incentives); in favour of CHP reforms 'very bad for the environment' and to reduce greenwashing
- However, sees **changes to network charging having a massive impact**: will add 5% to large companies' energy bills impacting on how they sell energy back to the grid, a 'double whammy'
- Again concerned about impact of changes on **viability of business case for energy investment**
- Believes **government needs to speak to business more**. Often they take business by surprise with new regulations. Less technical and complex communication needed.
- **Big Six also need to learn** from smaller firms (e.g. Bulb) – 'honest, visibility, clarity needed … show what the future looks like'. None educate their customers.

B.6 Interview with a leading Facilities Management company

- Energy investment case is always difficult to make, given board's demand for 3-year payback, and changes to policy are **making it increasingly difficult** (sometimes impossible) to secure investment
- Simply **understanding the impact of legislation is a major task** for them and a big drain on resources
- Though well intentioned in many cases, the **resulting uncertainty** from energy policy changes is having a chilling effect on energy investment
- Major effort is made to put in place energy saving measures. When policy changes make this no longer viable it creates a 'cry wolf situation' where boards are **less inclined to back future energy initiatives**. This is true in a client-supplier context like Mitie but also for internal energy teams
- Less tinkering, and a **longer-term commitment to policy, is needed**
- Greater engagement and **closer working with business** leaders – people with practical, real-world experience
- Believes it is very **difficult for smaller and less energy-savvy firms** to benefit from flexible energy

Appendix 4 - The need to address locational and residual elements together

1. Context

The UK electricity system will be facing exceptional challenges in the coming years. Meeting the medium-term and long-term carbon emission reduction targets will require intensive expansion of the use of low carbon electricity generation and decarbonisation demand. In the context of the targets proposed by the UK Climate Change Committee (greenhouse gas emission reductions of at least 80% in 2050) it is expected that the electricity sector would be significantly decarbonised by 2030, with increased levels of electricity production based on renewable energy sources and demand increased by the decarbonisation of segments of heat and transport sectors [1].

Given this structural change, it is projected that an unprecedented investment in onshore and offshore transmission infrastructure, interconnection and distribution networks may take place in the next decades and these investments may be the largest network reinforcements since the post-World War II expansion. The value investments projected by Imperial College is between £20 billion and £50 billion across onshore, offshore and cross-border interconnection transmission projects [2].

On the other hand, the rollout of flexible control systems and technologies, will provide unique opportunities for the radical shift towards a smart grid system and establish user driven network operation and design concept, that could significantly enhance the utilisation of existing network assets and hence reduce future investment in network reinforcement. Cost-effective location-specific charging of networks will be critical to facilitate cost effective transition to smart low carbon system. As this transition is increasingly challenging the present network charging regime, delivering these targets cost effectively will require fundamental review of the current basis of network charging.

2. Importance and key objectives of transmission network pricing

The overall objectives of network pricing can be summarised as follows [3]:
- *Cost reflectivity:* The users of the network should be charged according to the costs they impose on future network development and operation, and how these costs vary by different locations within the network and type of network user.

- *Long-term investment signalling*: Network charges should send clear cost messages regarding the timing and location of expected network reinforcements. In other words, apart from recovering total network costs, network charging also seeks to signal to network users the network investment costs they impose on the system, and how these costs vary at different locations on the network. This approach aims to encourage generators and consumers to make an efficient trade-off between the costs they impose on the system and other costs and revenue streams. For instance, when selecting a new site for a wind farm, generation developers may face a trade-off between the relatively high transmission costs they face in more remote parts of the country, as compared to the benefits of higher load factors available in these areas. On the demand side, there are similar trade-offs between the higher costs of accessing the transmission system and the lower costs of energy production or other factors such as labour and land that also vary across the country. Therefore, network charges should promote proper levels of competition in generation and supply markets.

- *Revenue recovery*: Network charges should allow network owners to recover the costs of building and operating network infrastructure.

- *Balance between transparency, practical implementation and cost reflectivity*: The methodological approaches employed to derive network charges should be always transparent and auditable. Furthermore, they should be easily implementable in practice. However, achieving cost-reflectivity inherently requires the application of sophisticated charging approaches that may not be easy to follow by network users.

- *Acceptability and fairness*: Network users should be treated in a non-discriminatory and equitable manner in order to ensure the acceptability of the charges.

3. Overview of Transmission Network Charging

The costs of electricity transmission are divided into two broad categories:

1. Infrastructure capacity and operating costs: To move power from one location to another, transmission infrastructure is required. The costs of building and maintaining the required transmission assets depend on their capacity to transport electricity from one area to another and on the distance over which this capacity is provided, regardless of any flow of energy over those assets.

2. Short-run system operating costs: Once energy starts to flow over the transmission assets, it imposes additional costs of two kinds.

- Constraint costs: When insufficient transport capacity is available to accommodate power flows, instead of transporting power from one area to another, expensive generators that would not be dispatched in an uncongested system have to be dispatched to ensure supply exactly equals demand in all parts of the system, giving rise to constraint costs.
- Cost of losses: the further energy travels along a transmission line, the higher the proportion of the energy that is lost. These losses have to be replaced, at a cost, by increasing total generation output accordingly.

In Great Britain, the Transmission Owners (TOs) recover infrastructure capacity and operating costs through Transmission Network Use of System (TNUoS) charges. The costs of constraints are recovered through Balancing Service Use of System (BSUoS) charges. The costs of transmission losses are allocated to producers and consumers by applying Transmission Loss Multipliers (TLMs) that marginally reduce the volume production with which generators are credited in settlement, and marginally increase the amount energy suppliers have to purchase.

Therefore, a key role of TNUoS charges is to allow the TOs to recover the costs of providing and maintaining transmission infrastructure. The total revenue to be raised through TNUoS charges is defined by the TOs' Maximum Allowed Revenue (MAR), which is determined to a large extent by Ofgem's decision regarding the level of revenue that regulated transmission companies are allowed to recover through their revenue controls.

The detailed charging methodology, through which the TNUoS charges faced by individual generators or consumers are calculated, is set out in Section 14 of the Connection and Use of System Code (CUSC). This methodology is based on the so-called Investment Cost Related Pricing (ICRP) approach, which aims to set tariffs according to the transmission investment costs that different network users impose on the system. More specifically, the modelling procedure estimates the change in power flows around the transmission system resulting from marginal changes in injections to the system at different transmission nodes. By multiplying the change in transmission flows by an "expansion constant", which represents the marginal cost of adding transmission capacity, the procedure estimates the change in transmission costs associated with marginally changing injections at each node. In this sense, the TNUoS methodology aims to be cost-reflective, and send economic signals to network users regarding the costs that their presence imposes on the transmission system.

One of the first steps required to set TNUoS charges is to determine the amount of revenue that has to be recovered through tariffs levied on demand (D-TNUoS) and generation (G-TNUoS). European Union (EU) rules limit the amount of transmission infrastructure cost that can be recovered from generators to an average charge range of €0/MWh to €2.50/MWh of generation output. The TNUoS charging methodology includes an error margin to ensure compliance and so at present, this cap limits the share of MAR that can be recovered from generators to only 16% of the total MAR.

In the UK context, the TNUoS charges for both demand and generation consist of two elements:

- **Locational**: Forward-looking locational signal that should broadly reflect the costs and benefits of embedded and transmission-connected generation on transmission system in different locations.
- **Residual**: Element used to recover the remaining costs of the transmission network, which are largely fixed and sunk cost (as well as some additional costs such as network innovation funding). This element does not vary across the transmission system.

4. Limitations of current regime and recommendations for future developments

The current charging regime exhibits certain limitations which need to be addressed in the context of developing more cost-reflective charging arrangements in the future.

4.1. Underestimating the locational element

As demonstrated by Imperial College modelling, under the current charging methodology, only around 10% of the total transmission cost comes through the locational element, leaving a large amount of revenue to be recovered through the residual charges [4] (Figure 1). This implies a very high level of cost socialisation. However, the current methodology asserts that this locational charge, which only recovers 10% of revenue, is the cost-effective component of the charge. Clearly, the current TNUoS charging methodology does not allocate charges to parties responsible for incurring network reinforcement nor provides locational incentives for generation, demand or storage. Fundamentally, transmission network are built as generation and demand are not in the same location - in other words, transmission is all about location and cost effective network charges must reflect this.

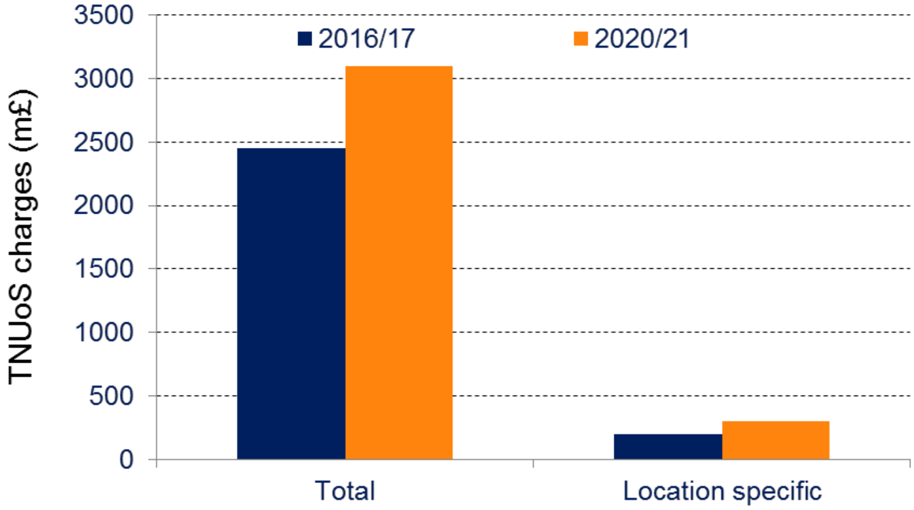


Figure 1.Quantification of elements of TNUoS charges

Having in mind the principle that the locational component is designed to be cost-reflective, it is very inefficient that locational element recovers a very small proportion of total network cost.

A relevant point of discussion is associated with the recovery of fixed investment costs. The reinforcement of network assets includes two cost components: i) the fixed cost, associated with installation works (e.g. deployment of transmission towers, undergrounding cables etc.) and not driven by the capacity of the reinforced asset and ii) the variable cost, which is proportional to the capacity of the reinforced asset. Although the fixed cost usually dominates the variable cost, socialising the former is clearly not cost-effective. The overall investment is driven by specific generators / consumers, who should bear these costs (including both fixed and variable components) through suitable charges. In other words, the fixed investment cost is also location-specific as it is caused by the needs of specific generators / consumers connected to the network.

Modelling by Imperial College also suggests that if the locational element of the charge was set closer to Long Run Marginal Cost (LRMC), the amount of revenue the locational charge recovers could increase materially. As shown in Figure 2 below, setting LRMC-based tariffs using “baseline” assumptions[9] on transmission costs would result in a moderate increase in revenue collected through the locational element of the charge to around 20% of total (see the third pair of bars) [4].

One of the main reasons for this modest effect on total revenue recovery is that the assumed marginal cost of expansion (£60/MW/km/year) is similar to the expansion constant used in the current TNUoS methodology. However, when this is increased to £180/MW/km/year, we see a material increase in the revenue collected through the locational element of the charge to around 60% of the total in 2016/17.

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Therefore, whilst we understand the concern about the rising level of the TNUoS residual, there are compelling reasons to believe that the issue is in large part being driven by flaws with the current locational element of TNUoS charges. Inefficiencies in both elements of TNUoS charges will be distorting behaviour in potentially different ways and need to be addressed together.

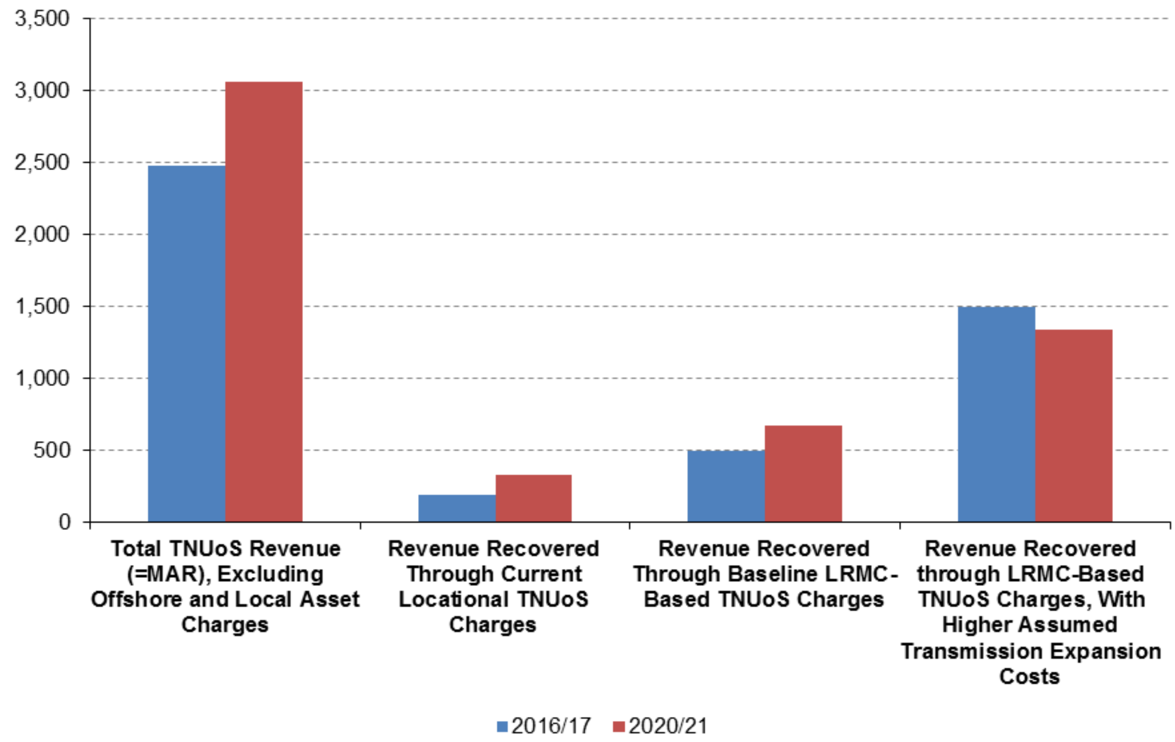


Figure 2.Revenue recovered through alternative transmission charging approaches (£m)

4.2. Choice of reference node

A relevant important point is associated with the setting of the “reference node” in the TNUoS calculation. The locational components are computed by estimating the change in transmission costs resulting from marginally increasing power injections at each node of the system (reflecting a marginal increase in generation) and removing this same amount of power from a “reference node” (reflecting the marginal increase in demand).

According to Figure 3 below, the total D-TNUoS charges do not depend on the reference node in the current charging methodology. However, it is clearly shown that placing the reference node towards North Scotland reduces the residual of D-TNUoS charges while placing the reference node towards South West increases the residual of D-TNUoS [4].

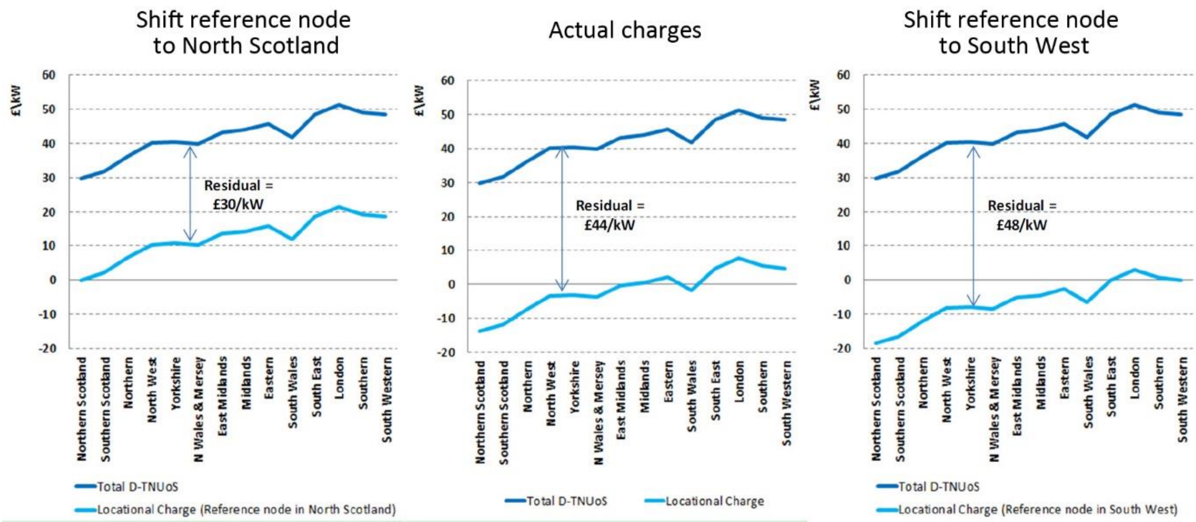


Figure 3. Total and locational D-TNUoS charges by demand zone - 2016/17

With the placement of a well-studied reference node, the cost-effective locational element of demand charges could rise and provide more effective signals that cover more transmission network costs.

4.3. Neglecting temporal elements

The proliferation of distribution-connected generation, the increase in intermittent renewable generation (particularly wind farms), the recent growth of storage assets and the potential for demand side management means that the existing historical network charging regime is increasingly becoming less cost-effective.

The nature of flows is changing and the maximum flows on individual parts of the network (which would drive losses and the network reinforcement needs) may not be strongly linked overall system peak demand. For instance, wind generators typically produce less during extreme winter conditions when demand is the highest. Instead, their production is the highest on windy days when overall electricity demand is lower than peak levels.

Therefore, the underlying objective of cost-effective charges cannot easily be fulfilled without considering time (apart from location), reflecting the actual flows on the network at each time.
According to Figure 4 below [4], the off-peak demand in Scotland is clearly driving the network reinforcement, however the locational element of current D-TNUoS charges does not account for differences in the transmission costs that users impose on the system in off-peak conditions, which ignores this increasingly important driver of transmission investment. Hence, the temporal signals in the present TNUoS charges are not efficient.

![centrica]

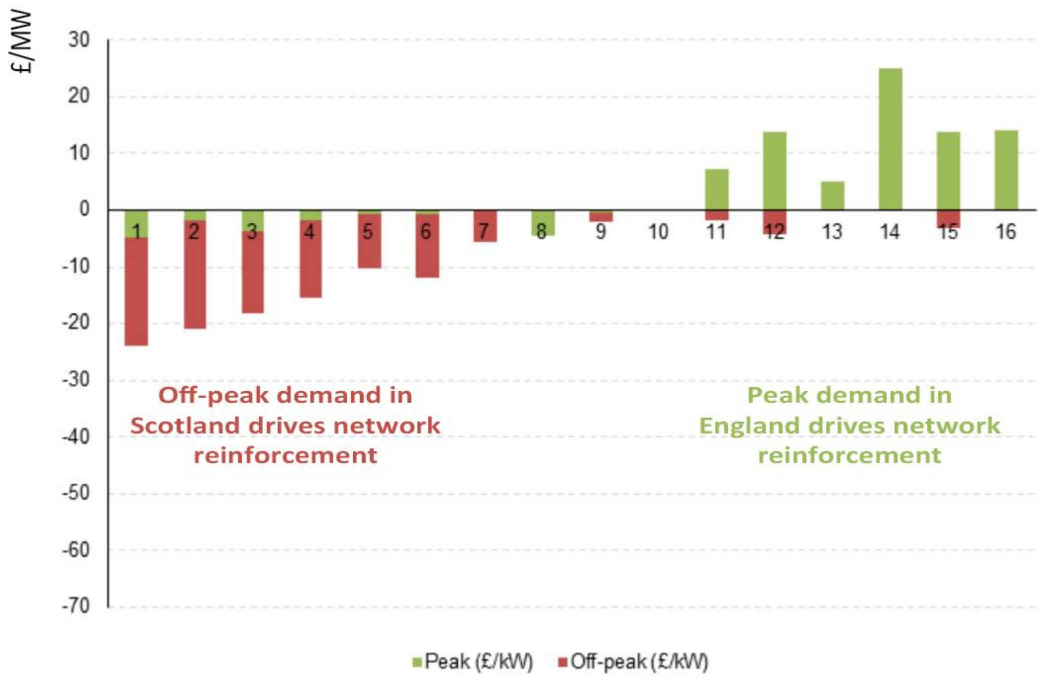


Figure 4. Illustration of temporal aspects of network charges

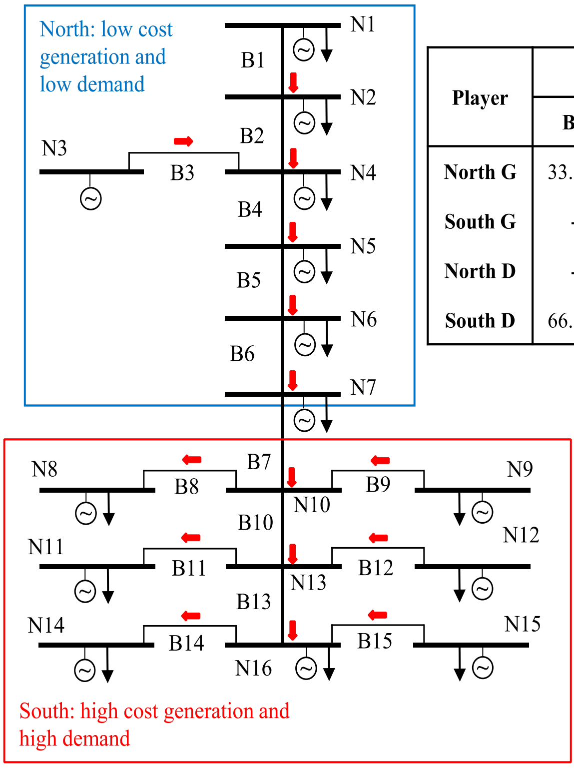
Importantly, the present charging review does not consider the transition to smart energy paradigm, which is critical for future network design (example provided in section 4.5).

4.4. Beneficiary pays principle

The "Beneficiary pays" principle has emerged as a theoretical foundation for the suitable allocation of network costs to different participants and the appropriate recognition of the locational element, discussed in Section 4.1. According to this principle, the cost of transmission assets should be allocated to those entities that economically benefit from these assets. This principle has been adopted by the Federal Energy Regulatory Commission (FERC) in the U.S.

In order to provide quantitative evidence of this principle and demonstrate which system entities benefit from having access to transmission assets and would be willing to pay for the associated costs, a novel game-theoretic modelling framework has been developed by Imperial College [7]. In this modelling framework, different self-interested entities make independent decisions on how much network capacity they will invest into (pay for) in order to maximise their individual profits. The decisions of the different entities are inter-dependent and therefore each entity accounts for the decisions of the rest of the entities in the system, on the basis of a non-cooperative game. Figure 5 illustrates an application of this modelling framework on a simplified 16-bus model of the GB transmission network [8].

The formulated game includes 4 general players: Generation (G) entities in the North and South, and Demand (D) entities in the North and South. In the North region, the demand is low while there is a significant amount of renewable and low-cost generation, while in the South region the large demand centres are present and generation is scarce and more costly. The table in Figure 5 shows the proportion of the capacity on key transmission boundaries that would be invested by different players, following the game-theoretic modelling approach. Unsurprisingly, low-cost generation in the North and demand in the South benefit from the transmission infrastructure; the former can access the large demand centres to sell their energy production at higher prices, while the latter can access cheaper energy than the one produced by local generators. On the contrary, demand in the North and generation in the South would see their surplus reduce with the increase in North-South transmission capacity.



Player	Players' capacity allocation per branch (MW)							
	B1	**B3**	**B4**	**B6**	**B7**	**B8**	**B9**	**B10**
North G	33.3%	17.9%	98.8%	63.7%	74.8%	75.0%	-	8.1%
South G	-	-	-	-	-	-	-	-
North D	-	-	-	-	-	-	-	-
South D	66.7%	82.1%	1.2%	36.3%	25.2%	25.0%	100.0%	91.9%

Figure 5. Application of game-theoretic approach in the 16-bus GB System

This example illustrates how the "beneficiary pays" principle can be used to inform the network pricing arrangements, and confirms that decentralised, profit-driven approaches to transmission network investment can provide fair outcomes with respect to the allocation of transmission costs. This approach is currently being used by Imperial College to assess the cost-effectiveness of existing network pricing methods.

4.5. Smart grid system: incorporating consumer choice in network investment and charging

At present, network design is based on network planners making assumptions about the demand and generation location, magnitudes etc. The rollout of flexible control systems and technologies, complemented with cost-effective location-specific charging of networks, will provide unique opportunities for the radical shift towards a smart grid system and establish user driven network operation and design concept. For example, there is growing evidence that demand management approach, where non-essential loads could be switched off at times of network/system stress, could significantly enhance the utilisation of existing network assets, while increasing reliability of supply. Clearly, this would result in a very significant enhancement of the reliability of supply delivered by the existing network, as significantly more consumers will have their essential demand supplied during events of outages and network congestion. Furthermore, this will, for the first time, open up the opportunity for user choice-driven network design, which is a core objective of a deregulated, market-based system.

Imperial College has presented an illustrative case study considering a primary substation with two transformers having a capacity of X MW each, as illustrated in Figure 6 (left) [8]. If peak demand increases above XMW, the application of historical N-1 security standards would require substation reinforcement, i.e. adding another transformer. However, in the fully decentralised market system, consumers should be making this decision. In this context, different shapes of the price-demand function representing different customer flexibility levels are illustrated in Figure 6 (right). The "Non-Smart" function corresponds to the inflexible demand (e.g. consumer valuing highly all their demand), while other functions correspond to different levels of consumers' flexibility, ranging from low (i.e. high valuation of supply of non-essential loads) to high (i.e. low valuation of supply of non-essential loads). Clearly, highly flexible consumers will generally have a more pronounced differentiation between essential and non-essential loads, enabled by smart technologies, and will be willing to switch off non-essential demand in response to very high locational charges (driven by cost effective charging approach).

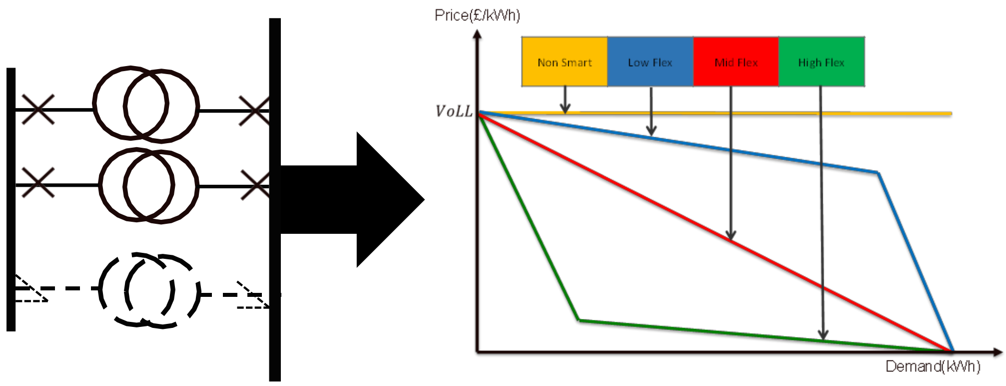


Figure 6.Test system and price-demand functions investigated

In order to demonstrate the benefit of demand flexibility in avoiding / postponing network reinforcement, the minimum level of Value of Lost Load (VoLL) at which it becomes justified to follow the historical network design standards (i.e. to add the third transformer), has been quantified across various scenarios of demand flexibility. The results are presented in Table 1. Different reliability scenarios correspond to different combinations of failure rates and repair times for each of the transformers and feeder sections, while different security levels correspond to different allowable margins between the total network capacity and the peak demand. (The case of N-1 network capacity margin has 100% margin and the N-0 case has no margin during peak demand conditions.) It can be observed that the breakeven VoLL level increases with higher customer flexibility, as well as with higher network reliability and security levels.

The colours for different breakeven VoLL levels in Table 1 below denote how much they deviate from a standard VoLL currently used in the UK (£17,000 - £22,000/MWh): green-shaded values are in the assumed range, blue-shaded values are lower, while orange-shaded values are higher.

Table 1.Minimum VoLL (in £/MWh) justifying reinforcement

Network Reliability	Security Level	Non Smart	Low Flex	Mid Flex	High Flex
Low	N-0.75	8,800	36,700	141,700	875,000
	N-0.5	3,400	8,200	29,000	182,100
	N-0.25	1,500	3,100	9,200	59,000
	N-0	700	1,200	3,400	21,500
Medium	N-0.75	44,400	185,900	725,600	4,375,000
	N-0.5	32,300	56,700	196,200	1,275,000
	N-0.25	7,600	15,200	48,300	312,500
	N-0	3,500	6,100	17,300	113,300
High	N-0.75	90,200	386,400	1,487,500	9,296,900
	N-0.5	35,400	85,000	303,600	1,961,500
	N-0.25	15,200	32,700	101,200	625,000
	N-0	7,400	13,100	35,400	229,700

In a scenario with highly flexible customers, the breakeven VoLL level tends to be very high, which implies that in those cases it would not be justified to add another transformer as overloading will be managed by flexible demand (or local generation and storage). On the other hand, if consumers are inflexible, consideration can be given to adding another transformer and allocating the corresponding investment cost to inflexible consumers accordingly. This analysis illustrates that historical network design standards may be inefficient in the future decentralised and digitalised smart energy system.

This demonstrates that demand flexibility can guide network designed (optimal level of network redundancy) at maximum efficiency, which in turn will affect the network charges faced by different type of consumers, as shown in Figure 7, where these charges are presented in relative terms (with the charges of consumers with low flexibility used as the reference) for customers with different flexibility, assuming fully cost-effective network charges in the future system.

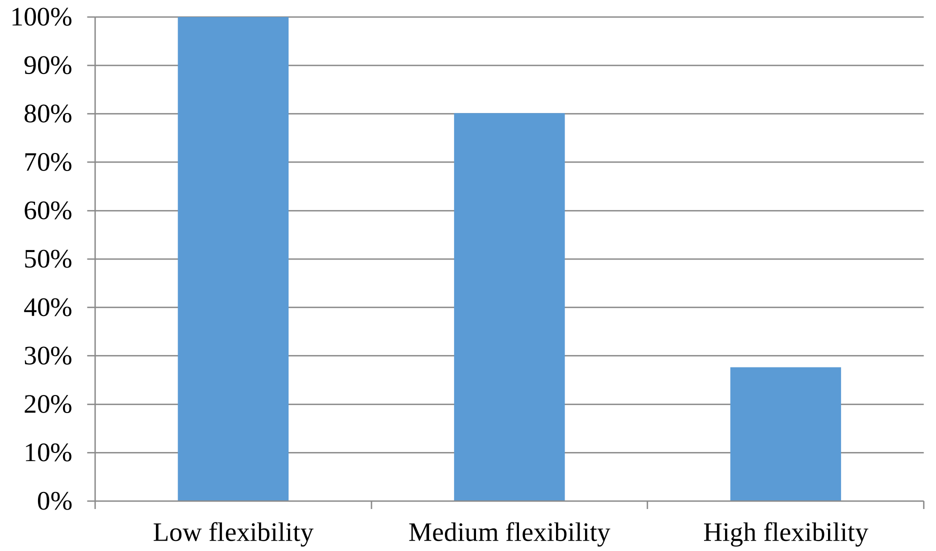


Figure 7. Relative network charges for consumers with different flexibility levels

The results show that flexible consumers who differentiate between essential and non-essential demand would be rewarded through significantly lower network charges. In the case study, the difference in network charges between customer categories is very significant, as charges for an inflexible customer may be over 3.5 times higher than charges for a highly flexible consumer. Implementing smart management of network overloads through disconnection of non-essential loads could further enhance the network utilisation and eliminate the need for network reinforcement, leading to savings above £3bn at the UK level by 2030 [1].

Introducing cost effective locational charges would enable much more efficient utilisation of network assets and facilitate user-led network development. Differentiation between essential and non-essential loads enabled by smart technologies will be critical for facilitating decentralised decision making, driven by consumers' choices. As expected, in case that flexible consumers reduce their demand when network charges are imposed, will enhance network asset utilisation and provide significant benefits to both flexible and inflexible consumers.

In the context of network charging, it should be noted that critical network conditions (network failures) requiring the disconnection of loads at the demand side or the contribution of embedded generation are very infrequent events. Therefore, the response from non-critical loads or embedded generation during these rare events would not have materially negative CO_2 implications, while it would potentially deliver very significant economic benefits. To achieve this, network pricing should be effective by imposing concrete charging signals (e.g. high charges during extreme conditions) and not be allocated ineffectively throughout long time periods (this balance can be established through appropriate carbon prices).

4.6. Further link of network charging with the low carbon agenda

In the context of delivery of the carbon targets, the GB electricity system is expected to undergo a fundamental transformation over the next couple of decades, as discussed in [1]. In its advice to Government on future carbon budgets, the Committee on Climate Change (CCC) has emphasised the importance of decarbonising the power sector and recommended that the aim should be to reduce the carbon intensity of power generation from current levels of around 350 gCO_2/kWh to below 100 gCO_2/kWh in 2030.

Delivering on such a target will require investment in a portfolio of low-carbon technologies and an increase in the provision of flexibility services to enable the cost-effective decarbonisation. Growth in required flexibility will facilitate development and deployment of innovative technologies and emergence of new business models and service offerings.

While there are several possible configurations of demand and supply, in any future low-carbon electricity system we should anticipate:

- Much higher penetration of low-carbon generation with a significant increase in variable renewable sources including wind and solar and demand growth driven by electrification of segments of heat and transport sectors;
- Growth in the capacity of distributed flexibility resource;
- Increased flexibility requirement to ensure the system can efficiently maintain secure and stable operation in a lower carbon system;
- Opportunities to deploy flexible technologies (e.g. energy storage) at both transmission and distribution levels;

- An expansion in the provision and use of demand-side response across all sectors of the economy.

In this context, cost-reflective market design and infrastructure charging will be critical. Hence, network charging should be fundamentally reviewed and ensure that flexibility is appropriately rewarded for eliminating network reinforcement and/or providing other system services and it is important that this reform is addressed alongside reform of residual recovery.

4.7. Managing conflicts and synergies between local network and national level objectives

In some cases, flexibility may drive network reinforcements in order to provide more valuable system balancing services, in which case it should be appropriately charged (in this case the revenues from the provision of other system services would be greater than the network charges). As an example, figure 8 shows the total system benefits of optimising the utilisation of flexibility taking the whole-system approach against local network centric approaches, in the case of relatively inflexible energy supply system (inflexible large-scale generation and limited interconnection). The whole-system solution is expectedly characterised by lower cost than the network centric approach, hence resulting in net savings [8].

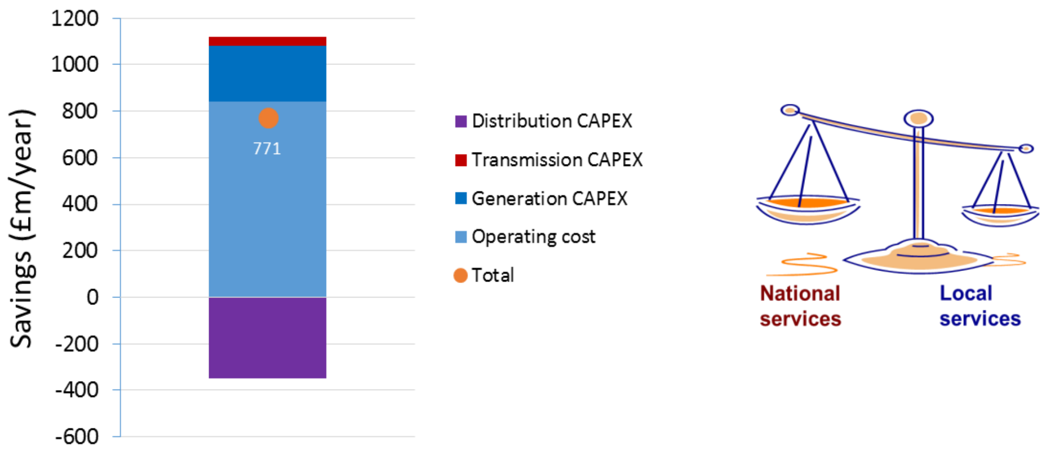


Figure 8: System cost savings from deploying flexibility based on a whole-system rather than local network centric approach

The benefit of the whole-system solution highlights the need for very cost reflective market design and network charging as this modelling demonstrates that the whole-system would benefit from investment in distribution network reinforcement. Such investment would enable end-use flexibility to balance variable renewable generation (reduce the corresponding operating cost) and also reduce the corresponding generation CAPEX needed to reach the CO2 target cost-effectively. In this case, flexibility providers would be willing to pay for distribution network reinforcement (through cost effective charges), as the revenues from providing balancing services at the national level would be greater than the increase in network chares driven by distribution network reinforcement.

It will be essential to acknowledge the value of decentralised flexibility by incorporating it into electricity markets which should provide cost-effective price signals, reflecting both national and local-level costs and benefits. Such decentralised concept that would provide market-integrated flexibility will enable consumers to make appropriate choices and facilitate cost-effective decarbonisation while reducing their energy bills.

In this context, fundamental review of transmission and distribution network charging regimes is required alongside reform of residual recovery.

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