

Decision

Targeted charging review: decision and impact assessment						
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We have decided to make changes to the way in which some of the costs of the electricity networks are recovered, so that the 'residual charges' are recovered more fairly now and in the future. We have also decided to remove some remaining distortions called 'non-locational Embedded Benefits' which can increase costs for consumers and affect competition.

 $^{^1}$ This document was updated on 18 December 2019 to amend data submitted by our consultants. This impacted some parts of tables 6 and 7 in this document and paragraph 3.103.

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Foreword

Targeted Charging Review

Laying the foundations for reforms to electricity network charging

The Targeted Charging Review (TCR) final decision set out in this publication is positive news for consumers. The costs of maintaining the electricity grid will be spread more fairly and consumers will save £300m per year from 2021, with £4bn-£5bn consumer savings in total over the period to 2040.

We have witnessed large changes in the way electricity is generated, transported and used in recent years as the UK moves to a smarter, lower carbon, and increasingly decentralised energy system.

After the government enshrined the new 2050 net zero emissions target in law in June this year, the pace of change will need to accelerate further.

As the energy regulator for Great Britain, Ofgem is laying the foundations for a net zero economy whilst ensuring the networks are run efficiently and costs are kept down for consumers.

The outcome of the TCR will help achieve this goal. It was set up in response to the changing role of the networks as more electricity is generated from a wider range of sources, including from smaller scale generators, and as demand becomes more flexible both in terms of time and location.

More and more businesses and households are generating their own electricity on-site, including from renewables such as solar power. However, these consumers still use the grid, for example on dark winter evenings when solar power cannot generate electricity.

The TCR has focused on the ongoing 'residual' charges which aren't supposed to send signals for how the networks should be used. These charges are currently largely based on an individual user's consumption from the grid. By taking less electricity from the grid by either generating their own electricity or taking other action, some businesses and households currently avoid paying (some or all of) these charges, despite being able to draw on the networks as and when they need. The cost that they avoid falls on those that are not able to take similar action.

The changes set out in this decision document will result in fixed residual charges for all households and businesses.

Many homes and businesses will save money as a result of these reforms. Some that generate electricity at home or on-site may pay more to better reflect the service they get from the network, but they will continue to enjoy benefits from generating their own electricity.

This TCR final decision will also reform the system of inefficient payments and charges which benefit certain power plants through the system of 'Embedded Benefits'. These distort the competitive market, unnecessarily add costs to energy bills, and do not reward the most efficient generators.

This decision, is part of a series of reforms that will ensure the costs of the network are kept as low as possible and shared more fairly across its users. Our ongoing "Access reform" project will tackle other components including so called "forward-looking" charges and enable consumers to save money by using the networks in the most efficient way possible, freeing up network capacity and ensuring it can be used more efficiently.

Ofgem's next price controls for networks, which will start from 2021, will ensure companies invest for a low-carbon future whilst driving significant savings for consumers.

With this programme of work, Ofgem is helping the energy system deliver the most effective route to a net zero emissions economy at the lowest cost to consumers.

Dermot Nolan Chief Executive Officer, Ofgem

Executive summary

Our energy system is undergoing a radical transformation as the process of decarbonisation, digitisation and decentralisation accelerates. We are undertaking a package of reforms to enable competition, innovation and decarbonisation at lowest cost, and to protect consumers in the transition to a smarter, more flexible and low carbon energy system.

These reforms include a comprehensive review of electricity network charging, being undertaken through two closely-linked reviews:

- The Access and forward-looking charges review is looking at the 'forward-looking charges' which send signals to users about the effect of their behaviour on the networks; and
- The Targeted Charging Review (TCR) has examined the 'residual charges' which recover the remainder of the total network charges needed to fund network expenditure.

The TCR has considered two elements of network charges within the Significant Code Review (SCR) process:² (i) reforms to how residual charges are set and (ii) the nonlocational Embedded Benefits.³,⁴ We have considered how residual charges can be shared more fairly in order to reduce harmful distortions from the current charging framework. The current charges are sending strong signals, which are not appropriate and which are increasing consumer bills. We have carefully considered our reforms, including their implementation dates, alongside our plans for the Access and forward-looking charges project and RIIO2 price controls.

We have decided to take action because of changes in the energy sector. More businesses and households are generating at least part of their energy requirement through solar panels, wind turbines or more traditional generation technologies. Electricity storage is also

 $^{^{\}rm 2}$ The SCR process provides a tool for Ofgem to initiate wide ranging and holistic change and to implement reform to a code based issue.

³ Embedded Benefits are differences in transmission and balancing charges for smaller generators compared to larger generators, which are now leading to payments to all generators. The TCR has considered the remaining 'non-locational' Embedded Benefits following our decision on CMP264/265, and the Access and forward looking charges review is considering the 'locational' Embedded Benefits. ⁴ In addition, the TCR has considered reforms to storage charging outside of the SCR process, and these are not covered by this decision.

becoming more common and there is an increasing uptake of electric vehicles and heat pumps. Electricity increasingly flows from the distribution networks onto the transmission network, as well as in the other direction. This has meant that the existing approach to network charges no longer reflects how the networks are used, and the current regime shifts the recovery of these charges onto an increasingly smaller group of users. The rapid pace of changes mean that the issues with the existing charging structure are likely to become worse over time. We are therefore taking action to address this and to ensure that network charging works in the interests of both current and future consumers.

We have, after conducting and reflecting on public consultations, stakeholder views and feedback, reached a final decision on the TCR SCR, including implementation dates and the next steps to be taken.

We have assessed options against the three principles we set out at the start of our review:

- reducing harmful distortions,
- fairness, and
- proportionality and practical considerations.

Following careful consideration of the responses to our consultations on 28 November 2018, 17 June 2019 and 3 September 2019, we have decided to levy residual charges on final demand users, making residual charges simpler and more transparent, and have decided to implement a refined version of a fixed charge for the collection of residual network charges. We have decided that these reforms should be implemented in stages, which will help to mitigate the distributional impacts, with reforms to transmission charges being introduced in 2021 and distribution charges in 2022.

We have also decided that action is required to address each of the three embedded benefits we outlined in our consultation of 28 November 2018 (the "minded to consultation"), but have decided only to reform two of these aspects directly through our direction on the SCR. We have decided that the Transmission Generation Residual charges should be set to zero⁵, and to remove the ability for suppliers to reduce their liability for balancing services charges by contracting with small distributed generators⁶. This will be

⁵ This is subject to ensuring compliance with the EU Regulation on 838/2010

⁶ Small distributed generators are connected to the distribution network and with capacity less than 100 MW.

achieved by recovering balancing services charges for demand on a gross consumption basis, rather than a net consumption basis at the point the transmission network meets the distribution network – the Grid Supply Point. These reforms will be implemented in 2021.⁷

Lastly, rather than taking direct action to remove the third Embedded Benefit (which is that small distributed generators do not pay balancing services charges) as part of this SCR, we have decided to launch a second Balancing Services Charges Taskforce (the "Taskforce") to apply the TCR principles to the recovery of balancing services charges. Specifically, the Taskforce will consider who should pay balancing charges and on what basis, and it could lead to fundamental reforms to these charges, including the possibility they are recovered on a consistent basis as the new transmission and distribution residual charges being implemented by this decision.

The reforms to Embedded Benefits will affect revenue streams for all generators (including renewable generators). Our analysis indicates that by removing distortions caused by these charging arrangements, similar levels of decarbonisation can be delivered at significantly lower costs to consumers.

Our analysis indicates that these reforms will provide significant savings to consumers of ± 3.8 bn to ± 5.3 bn and system benefit of ± 0.8 bn to ± 2.9 bn over the period to $2040.^8$

Any change to network charges will have different effects on different types of consumer and rebalancing the allocation of these charges will inevitably mean some consumers will pay more and some will pay less. For the majority of consumers at present, charges are paid by retail suppliers who then decide how to pass these costs on to end consumers.

The two elements of TCR reform will have different impacts on consumers. All consumers will benefit from the removal of Embedded Benefits. While the introduction of new residual charges will benefit consumers overall, some will pay lower charges and others will pay higher charges than today.

⁷ Although it is possible that these reforms are eventually superseded by the conclusions of the second Balancing Services Charges Taskforce, we believe action now is in the interest of consumers.
⁸ This is the indicative modelled costs of our reforms, these are NPV values calculated using the green book discount value of 3.5%. These figures are based on 'partial' reform of the other Embedded Benefits under two Future Energy Scenarios, and does not include further benefits that will arise from reforms to balancing charges.

On average, households will pay less than today and non-domestic consumers will pay more. Consumers who currently benefit from reduced contributions because they have onsite generation which has reduced their contribution to the existing system, without a corresponding reduction in system costs, will pay more on average. Those that haven't taken such action will on average pay less.

By changing the charging basis to a fixed approach, this means almost all consumers will face a different level of charges than at present. On average this means, those towards the top of the charging bands will pay less than today, and those at the bottom of the charging bands will pay more. However, those facing an initial increase will benefit from the longer term savings from our proposed changes.

Most domestic consumers will save as a result of the reform to fixed charges, with a typical household seeing a ± 5 /year reduction in their bill. However, some households who use the least electricity could face a typical annual increase of between ± 2 and ± 22 a year when these changes fully come into effect in 2022. This will however be offset partially by the long term benefits of reform. We carefully considered the impacts of reforms on vulnerable consumers, but found them to be present in all consumption categories. We think targeted approaches for supporting vulnerable consumers are more appropriate than changes to the network charging arrangements.

Our Access and forward looking charges review is examining the signals to network users to behave in the most efficient way for the system as a whole, while we continue our drive to open up markets to flexibility and new technology to lower costs for consumers. The TCR changes are an essential part of a package of reforms to network charging and will place the residual charging arrangements on a sustainable footing for the future..

1. Introduction

Context and related publications

1.1. The TCR forms one of the core components of our programme of reforms. The TCR has considered how residual charges can be recovered more fairly in order to reduce harmful distortions in the current charging framework, and undertaken reform to the remaining Embedded Benefits, within the SCR process. A separate element of the TCR, outside of the SCR process, is the associated reforms to residual charging arrangements for storage facilities.⁹

1.2. The Access and forward looking charges review is considering reforms to network access and forward-looking charging within a separate SCR process, with industry taking forward associated reforms to access rights, including improved queue management and the scope for trading, outside of the SCR process.

1.3. This document provides our final decision on the TCR SCR and explains our reasoning for making it.

Background and wider reforms

1.4. The energy system is undergoing a transformation, as electricity is both generated and used in different ways, at different locations and at different times to historical patterns. Historically, consumers have been largely passive participants in energy markets with electricity flowing down from generators from high to low voltages as it is transmitted and distributed. Total consumer demand at any point in time has been seen as mostly 'fixed' and generators, such as coal and gas powered plants, have been the 'flexible' part of the system, adjusting generation output to meet demand.

1.5. As the electricity system decarbonises, there are increasing amounts of intermittent renewable generation on the system, which has a less flexible output as it depends on external factors, such as wind or sunlight, as the source for electricity generation. In addition, demand has become increasingly responsive with the advent of Demand Side

⁹ These reforms are progressing through the open industry process.

Response (DSR) technologies. Therefore, increasingly, we need more flexibility in the electricity system. New technologies for which costs are decreasing such as batteries, electric vehicles (EVs) and DSR are key enablers for this flexibility.

1.6. Users benefit from being connected to the electricity networks, through the sharing of assets and reduced costs provided through economies of scale. The networks enable users to access reliable generation that would usually be more expensive to provide on a standalone basis to individual sites.

1.7. There are, however, ongoing costs of building, maintaining and operating the grid which have to be recovered. We think it is important that users benefitting from the network infrastructure are contributing fairly towards its operation and maintenance. In addition, where users contribute to increased network costs or behave in ways that will save future network costs, we think it is appropriate they receive charging signals that reflect this.

1.8. Ongoing electricity network charges for using the system have two elements:

- Forward-looking charges, designed to ensure network users (via suppliers for most consumers) receive signals that reflect the costs of how and when they use the networks. These cost-reflective signals can encourage users to be flexible in their use of the network, which increases the overall network efficiency whilst reducing their own electricity bills. This benefits all users.
- Residual charges, designed to recover the rest of the relevant network company's allowed revenues (under its price control) once forward-looking charges have been levied, which should not send signals to users. These charges are required because forward-looking charges do not usually fully recover the costs of the whole network.

1.9. The total costs which can be recovered by the network operators are determined through our RIIO (Revenue=Incentives+Innovation+Outputs) price controls. These set the total revenue the network companies are allowed to earn while ensuring the overall costs of the network are kept as low as possible. This total revenue is then recovered through a combination of forward-looking and residual network charges.

Problem statement

1.10. Whilst residual charges themselves are not set directly through price controls, the total revenue that they can recover is limited by price controls because they make up the difference between the total price-controlled allowable revenue and the forward-looking charges. As a result, this is a 'fixed' amount of money each year that the network operators need to recover through residual charges and typically comprises 10-15% of a user's electricity bill.

1.11. Currently, network users pay different residual charges depending on which voltage level they are connected at, which region they are located in and if they are a demand consumer or a generation producer.

1.12. The distribution residual charges are levied almost entirely on demand and differ for Low Voltage (LV), High Voltage (HV) and Extra High Voltage (EHV) connectees. For LV consumers, residual charges are collected from smaller users on a per-unit electricity (net) usage basis and from larger (HV and EHV) users through a combination of per-unit capacity charges for distribution and 'triad' charges for transmission charges.

1.13. The transmission residual charges have historically been levied on both demand and generation, through the Transmission Demand Residual (TDR) and the Transmission Generation Residual (TGR) charges. Recently, the TGR charge has become negative so has become a benefit to all generators who receive it, and we are removing this payment through the TCR decision. The TDR charges are recovered¹⁰ on the basis of peak demand at each Grid Supply Point (GSP), determined by 'Triad'. Triad is a mechanism which measures electricity usage at three half-hour peak periods of demand each year, which are determined ex poste (and hence not known in advance). This incentivises users to reduce their electricity demand from the network particularly in anticipation of the triad periods or to use on-site generation and storage instead of grid-supplied electricity.

1.14. As the electricity system changes and the costs of new smaller and onsite technologies reduces, more users are able to invest in ways of reducing their use of electricity drawn from the networks. This can be good for the system and for consumers where there is a consequent reduction in network costs (which is covered by the Access and forward looking charging reforms).¹¹ However, under the current arrangements, these

¹⁰ Embedded Benefits related to the TDR are being phased out over three years from April 2018.

¹¹ This is because residual charges are the difference between forward-looking charges and the

users can also save on their share of the residual charges. The amount by which they reduce their residual charge is then spread across the remaining network users, increasing their share. As a result, an increasing number of users who are able to reduce their residual payments means an increasing amount of the residual charge is falling on users who cannot or do not reduce the electricity they take from the network. We do not think this is appropriate as there is no associated reduction in system costs through responding to the signals sent through residual charges.

1.15. In additional to the harmful distributional aspects, these behavioural changes can increase the costs of running the network, and incentivise generation which does not help meet decarbonisation targets and is often not beneficial to the system as a whole. In the long term, this is unsustainable as it could lead to decreasing numbers of users paying for an increasing proportion of network costs.

1.16. The issues raised are similar for non-locational Embedded Benefits, where charges not designed to send signals are leading to strong market responses. Embedded Benefits are historical charging arrangements which have favoured Smaller Distributed Generators (also called embedded generators) by allowing them to contract with suppliers to help suppliers reduce their exposure to charges and get paid for doing so, or to avoid paying charges that other generators pay. These different charging arrangements now lead to a range of benefits and disbenefits to Smaller Distributed Generators compared with other generators.

1.17. The TCR has focused on three specific elements of non-locational Embedded Benefits:

- Larger generators are liable for generator residual charges, whereas Smaller Distributed Generators are not. As the TGR has become negative, it has become a benefit to those who receive the TGR credits, which are the transmission-connected and larger distributed generators.
- Balancing services charges recover the costs incurred by the system operator for keeping the system balanced and the day-to-day operation of the system. Balancing

allowed revenue under the price control, making this an annual 'fixed' amount of money to be recovered.

services charges are recovered approximately 50% from demand and 50% from generation, based on net consumption at the GSP, measured each half-hour. Smaller Distributed Generators can receive payments from suppliers for helping them to reduce their liability for balancing charges for demand, and is hence an Embedded Benefit favouring Smaller Distributed Generators.

 In addition, smaller distributed generators do not pay balancing service charges for generation (whilst larger generators do), which is another Embedded Benefit related to these charges.

1.18. We have clearly and consistently signalled that we think reforms are needed to all of these arrangements, since we started the review of these arrangements in 2016.¹² In addition, the 'locational Embedded Benefit', whereby Smaller Distributed Generators do not face forward-looking charges on the transmission network, is being reviewed as part of the Access and forward-looking charges review, and this is another area we have consistently indicated requires reform.

1.19. The government has recently committed to reducing carbon emissions to net zero levels by 2050.¹³ The government has stated that 'Overall, emissions from electricity generation have decreased by 65 per cent since 1990, despite final consumption of electricity being provisionally estimated to be around 11 per cent higher in 2017 than in 1990'.¹⁴ The modelling we have undertaken suggests that overall the combined impact of the TCR changes will reduce carbon emissions compared with no reforms.

1.20. We recognise that some users will see increased costs under these reforms but we expect there to be significant system and consumer benefits overall. Network charges should recover the costs of the network as fairly as possible whilst encouraging efficient use of the network which benefits all users.

¹² <u>https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter__</u> <u>charging_arrangments_for_embedded_generation.pdf</u>

¹⁴<u>https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file</u> /695930/2017_Provisional_Emissions_statistics_2.pdf

¹³ <u>https://www.theccc.org.uk/wp-content/uploads/2019/05/Net-Zero-The-UKs-contribution-to-stopping-global-warming.pdf</u>

1.21. These changes are proportionate and in line with the European Energy Directive II, a European Union plan for increasing renewable energy generation¹⁵ and the reforms are complementary to domestic programmes too, including the Smart Systems and Flexibility Plan we produced with government, which considers the changes needed in order to deliver a smarter, more flexible energy system.¹⁶

1.22. The reforms that will be implemented as a result of this decision will reduce the current harmful distortions and, alongside the work to reform access and forward-looking charges, and the second Balancing Services Charges Taskforce, will ensure that there is more efficient use of the network.

1.23. This document provides our final decision on the TCR SCR and explains our reasoning for making it.

¹⁵ <u>https://ec.europa.eu/energy/en/topics/renewable-energy/renewable-energy-directive/overview</u>
¹⁶ <u>https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-</u>
_smart_systems_and_flexibility_plan.pdf

2. Our Approach

Chapter summary

This chapter summarises the assessment process we have undertaken and describes the methods used to reach our final decision on the TCR SCR for reform of residual charging arrangements and 'non-locational' Embedded Benefits. It provides an overview of the three TCR principles which underpin the principles-based assessments and describes how wider systems analysis was used to consider the potential outcomes of the reforms in different future energy scenarios, particularly with respect to consumer and system benefits.¹⁷

2.1. We launched the TCR in 2017, following the decision to remove the largest Embedded Benefit related to TDR charges, and after consultation with industry.¹⁸ It is part of a wider review of network and system charges which includes the Access and forward looking charges review and the ongoing work to review balancing services charges.

2.2. We developed the three TCR Principles which, following consultation, were then used to make the principles-based assessments. We commissioned expert consultants to support these decisions through wider systems analysis to consider how proposed changes would impact the system and its consumers. We published a number of documents to keep stakeholders informed, and engaged widely with industry stakeholders through the Charging Futures Forum, webinars, workshops and other meetings to reach this decision.¹⁹

The TCR process

 ¹⁷ The future energy scenarios are produced by National Grid to consider the possible change to the electricity system and what the implications of this might be. Further information on these can be found at https://www.nationalgrideso.com/insights/future-energy-scenarios-fes

 ¹⁸ <a href="https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators</p>

¹⁹ <u>http://www.chargingfutures.com/</u>

2.3. Figure 1 shows the main stages and publications of the TCR. In March 2017, we consulted on launching the TCR. In August 2107, following strong support from stakeholders, we formally launched the TCR SCR and followed this, in November 2017, with a working paper which updated stakeholders on our approach for reviewing the residual charging arrangements and Embedded Benefits. Our letter also set out our thinking that only final demand consumers should pay residual charges. We held two workshops in November 2017 to allow stakeholders an opportunity to feed in their views and discuss the working paper.

2.4. We sought further input from stakeholders through two technical workshops held in April 2018, which provided an opportunity for views to be expressed about the wider systems modelling, user groups and our analytical work in general.

2.5. In August 2018, we held a webinar to provide updates to stakeholders on the TCR project, and gather views on our static analysis of the proposed 'vanilla' or 'basic' recovery mechanism options and on the potential refinements which could be applied to these options.

2.6. We carefully examined industry feedback, and took it into account when we reached our minded to decision, which we published for consultation in November 2018. These proposals were the result of the principles-based assessments of a wide range of refined options for recovering residual charges and supported by the wider systems modelling. These consultations included our proposals for reform of Embedded Benefits which were reached using the same approach.

2.7. The first Balancing Services Charges Taskforce was launched at the same time as the minded-to consultation was published. It was asked to consider:

- if any elements of balancing service charges currently provide a forward-looking signal,
- if there is potential for any elements of balancing services charges to be charged more cost-reflectively and hence provide better forward-looking signals, and
- if it is feasible for any identified potentially cost-reflective elements of balancing services charges to be charged on a forward-looking basis.

2.8. The taskforce held a series of industry meeting and workshops and then published its draft conclusions that balancing services charges do not provide useful forward looking

signals and should be considered as cost-recovery charges. It sought views on these conclusions. There was wide support for its conclusion among stakeholders. We then allowed a further four-week consultation for stakeholders to provide feedback on the taskforce conclusions and how they should be considered within the context of the TCR.

2.9. In May 2019, we issued an update on our implementation timelines, which stemmed from our decision to undertake an additional sensitivity analysis following the unexpected suspension of the Capacity Market in November 2018.²⁰ This analysis was published in June 2019.

2.10. In September 2019, we consulted on a refined version of our fixed charges option with refined banding for non-domestic consumers, aimed at addressing concerns raised in response to the minded to consultation. We also held a workshop allowing stakeholders opportunity to provide feedback on these proposals. Alongside this, we published a further sensitivity analysis to test the robustness of the implication of the reforms on renewable generators, given changes in government support for renewable technologies.²¹

2.11. We have also engaged with stakeholders through the Charging Futures Forum, which has provided, and continues to provide, information to stakeholders and an opportunity to input into the TCR and other charging reviews. Our final decision on the TCR SCR has been reached after carefully considering all the responses to these different consultations and taking into account written and verbal information provided to us during the considerable stakeholder engagement we have maintained throughout this SCR. Further information on the decisions and the reasons for them is given in Chapter 3 for residual charges and Chapter 4 for Embedded Benefits. Figure 1 below shows the main stages in the TCR process.

 ²⁰ <u>https://www.ofgem.gov.uk/publications-and-updates/future-charging-and-access-programme-consultation-supplementary-analysis-november-2018-minded-decision-targeted-charging-review
 ²¹ Renewable technologies eligible to bid for Contract for Difference (CfD) contracts were confirmed as only 'pot 2' technologies, primarily off-shore wind, for the 2019 round. There are further details in Chapter 5, Quantifying the benefits and Chapter 3: Decision on 'non-locational' Embedded Benefits.
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Figure 1 Timeline showing the key stages and publications of the TCR SCR



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2.12. We undertook a detailed review of relevant academic research, which we published alongside our minded to consultation.²² This provided us with particular insights into our fairness and reducing harmful distortions assessments, and supported our final decision that economic efficiency is maximised when residual charges are recovered in a way which minimises the distortion to users' efficient behaviour.

2.13. There is a strong basis for recovering residual charges on a fixed basis in academic research and literature, and we have taken into account the relevant academic research and reviewed regulatory approaches taken in other countries to residual charges.

2.14. We engaged directly with academics from the Ofgem Academic Panel on multiple occasions during the review and sought their advice regarding types of charges which best reduce the harmful distortions arising from the current charging regime.²³ This included engagement at an early stage during the review to help shape our thinking and later in the process as part of our assurance process.

2.15. We also reviewed international experience for lessons for the GB market. We commissioned consultants to investigate how other countries have addressed similar challenges. Our final decision builds on the approaches of Australia, (some parts of) the USA, and Italy, by increasing elements of fixed and agreed capacity charges.²⁴

Consumer research

2.16. We were keen to seek consumer views on our approach to fairness and residual cost recovery, to ensure our policy was informed by the views of GB energy consumers. Our Consumer First²⁵ research programme helps us to understand the priorities, views and experiences of a wide range of consumers, including business consumers and more

²² Details of this academic research and work commissioned from Cambridge Economic Policy Associates (CEPA) and TNEI to review how other countries have responded to cost-recovery charge design issues arising from increased onsite generation can be found in Annex 3 of the minded-to consultation which can be found at <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 3 -</u> <u>academic research and international comparisons.pdf</u>

²³ The panel is made up of twelve academics with a wide range of experience including regulatory economics, competition economics, behavioural economics, statistics and econometrics, and economic evaluation. More information can be found at https://www.ofgem.gov.uk/about-us/how-we-engage/government-and-parliamentary-relations/ofgem-s-academic-panel

²⁴ <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 3</u>_____academic research and international comparisons.pdf

²⁵ <u>https://www.ofgem.gov.uk/publications-and-updates/ofgem-consumer-first-panel-understanding-consumers-views-residual-network-charges</u>

vulnerable groups. We met with a group of everyday domestic consumers recruited from four locations across GB and commissioned independent qualitative consumer research, to test our positions.

Assessment of the options

Principles-based assessment

2.17. For both residual charges and Embedded Benefits, we adopted the same approach of using a principles-based assessment to determine the options which best met the criteria. We then commissioned consultants to assess how these options would have an impact on the wider system.

2.18. Our Principal Objective is to protect the interests of existing and future energy consumers. This closely aligns with all three of our principles. Reducing harmful distortions protects consumers since anything which distorts wholesale markets is likely to increase network costs impacts consumer prices in the short and long term. Fairness between end consumers of energy is an important aspect of protecting consumers. We also have responsibilities to ensure that industry participants are treated fairly (on legal and procedural grounds) and consistently, and that the markets in which electricity, and services for its production, are sold are functioning well is promoting effective competition. By having proportionality and practical considerations as a TCR principle, we can also ensure that we do not overburden energy market participants with new processes. We have been mindful of our environmental obligations and have formally assessed the carbon impacts of proposed reforms. In doing so we are trying to be fair, proportionate and practical.

Reducing harmful distortions

- Through our decision to amend the existing arrangements, our aim is to reduce the harmful distortions caused by the current residual charging arrangements which encourage some people, businesses and other organisations to reduce their exposure to residual charges.
- We want to minimise the potential for, and impact of, any new distortions introduced as a result of changes to the residual charging arrangements. Any method of residual charging is likely to lead to some distortions, but we want to reduce these as much as possible to ensure that the energy system works efficiently in the best interests of consumers.

Fairness

- We consider 'fairness' both in the allocation of residual network charges overall and relative fairness in the trade-offs between the options we considered. For residual charges we considered 'fairness' as it applies to, and among, end-consumers of electricity. This included specific consideration to residential and microbusiness consumers, and to consumers in vulnerable situations.
- When we considered Embedded Benefits, which primarily relate to different treatment
 of generators rather than end consumers. As we explained in the TCR working paper,
 'we think that reasonable treatment of industry parties is appropriately covered under
 our 'reducing distortions' principle, which will facilitate a level playing field between
 competing network users, and under proportionality and practical considerations, which
 includes consideration of the potential effects of material changes to charges'.²⁶
- We worked with academics and consumers to develop a detailed framework for assessing fairness as it applies to residual network charges. We commissioned consultants to explore and engage with consumers regarding their perceptions of fairness and how they felt it applied to residual charges.²⁷ We also explored academic literature around ideas of energy justice.²⁸ Our fairness assessments have been shaped by this research, which helped to define the components of fairness we used.

Proportionality and practical considerations

 We have worked to reach a decision that is proportionate to the harmful distortions caused by the current charging arrangements. We have ensured that the decisions taken have practical solutions which do not impose an overly complex financial or administrative burden on the electricity system and its generators, suppliers and users, We have also ensured that it is proportionate to the benefits that the changes are expected to bring for consumers.

 ²⁶ This is explained further in Annex 5 of the minded to consultation <u>https://www.ofgem.gov.uk/ofgem-publications/143415</u> and the TCR launch letter <u>https://www.ofgem.gov.uk/system/files/docs/2017/08/tcr_scr_launch_letter.pdf</u>
 ²⁷ <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex_1 - tcr_principles.pdf</u>
 ²⁸ Energy justice aims to provide all individuals, across all areas, with safe, affordable and sustainable energy. 2.19. To support our principle-based assessments, we commissioned consultants to carry out wider systems analysis of the potential policy options. This modelled the options to set out the potential impacts of the reforms on the revenues and costs of different generation types, and the behavioural changes of different generation types in the markets they participate in. The modelling also provides indications of the potential costs and benefits for the system as a whole and for consumers. Chapter 5 provides a detailed overview of the modelling and its outputs.

Quantitative assessment

2.20. The scope of this SCR includes two components:

- reform of residual charging for transmission and distribution, for both generation and demand, to ensure it meets the interests of consumers, both now and in future, and
- review of the other non-locational Embedded Benefits that are distorting investment and/or dispatch decisions, and increasing costs to consumers.

2.21. The first step in our analysis was to clarify and understand the effects of the current arrangements on users' charges and the behaviours these incentivise. We then sought to investigate how these incentives change under potential alternative charging reforms. Our analysis included:

- the impacts of retaining the status quo,
- the impact of change on individual users, across a broad range of sectors,
- the likely distribution of charges across these users combined with the incentives that they face as a result of the signals provided by the cost-reflective charges, and
- the impact of change on the most vulnerable users, and on those large users for whom energy costs represent a significant amount or who are most likely to have the ability and means to avoid these charges.

2.22. While the TCR principles outlined above helped guide this work and provided an assessment framework, we also conducted and commissioned the following quantitative work:

- distributional analysis: based on a static bill impact analysis of the effect of our options for reform on a range of representative domestic, commercial and industrial consumers,
- behavioural analysis: assessment of the potential for behaviour to be affected in relation to how/when customers use the network, choose to use on-site generation and adopt new technologies, including EVs and heat pumps,
- wider systems impact analysis: system modelling of the implications for the costs of operating the electricity system and costs to consumers until 2040, and
- research reports which we published alongside our minded-to consultation.

2.23. We commissioned consultants and undertook various pieces of research for this project, which provided the supplementary reports for this consultation including:

- Frontier / Lane Clark & Peacock (LCP) Distributional and wider system impacts of residual charges,
- Frontier / LCP Wider System Impacts of Transmission Generation Residual (TGR) and Balancing System Use of Services (BSUoS) reform,
- Revealing Reality Understanding Consumers' Views on Residual Network Charges (consumer panels to consider consumer views on residual charges), and
- TNEI and CEPA International Review of Cost Recovery Issues (how residual charges have been implemented in other jurisdictions).

2.24. Since our minded-to consultation, we have undertaken a range of sensitivities to better understand the robustness of our quantitative modelling, described in detail in Chapter 5, Quantifying the benefits.

Narrowing down options

Residual Charges

2.25. In our November 2017 Working Paper, we set out that our principles-based assessment of possible options had led us to seven possible charging mechanisms for setting residual charges. We assessed these options, and, through workshops in 2018, narrowed them down to four basic options for reform that we consulted on.

2.26. We worked with our consultants to define and refine the options, to create our indicative users and to carry out distributional analysis as well as the wider systems analysis which supported our principles-based assessments. This is shown in Figure 2 below.

2.27. We also commissioned work to consider behavioural changes that are likely to occur as a result of changes to residual charges. These behavioural responses contributed to three further pieces of analysis:

- The assumptions and baseline levels of charges were used to determine distributional impacts. This analysis accounted for the possible changes to user bases (such as the number of users that use EVs or heat pumps) that might occur if technologies that better supported reduction in exposure to residual charges were to take place.,
- The design of scenarios, for wider systems modelling, to show multi-year consumer costs and benefits resulting from change.
- We subsequently commissioned our consultants to undertake a longer-term distributional study to understand the longer term effects of reform on domestic consumers.

2.28. Work was also undertaken by our Office for Research and Economics (ORE) who considered how large users might respond to changing the way in which residual charges are recovered, particularly if they have a large onsite generation capability. We wanted to consider the potential likelihood of such users disconnecting from the network if new residual charges were introduced which were unrelated to net volumetric usage of electricity. This work concluded that large scale disconnection was unlikely but identified a number of considerations which we have taken into account.²⁹

2.29. After identifying the strengths and weaknesses of the variants of the basic options to refine them, five options were analysed further and we undertook static modelling to accompany this analysis. Behavioural responses were considered, and wider systems scenarios were mapped to these options and modelled to provide approximate consumer

²⁹ <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 6 - large users.pdf</u>

benefit estimates. This assessment resulted in the two leading options which we included in in the minded-to consultation.

Figure 2 Diagram showing the stages of refining the residual options



Embedded Benefits

2.30. Our approach to Embedded Benefit reform was similar to that outlined for residual charges. First, we considered the full set of the non-locational benefits that are causing distortions, utilising our TCR principles to narrow down our priority areas for reform.³⁰ We then undertook a detailed quantitative assessment to assess the likely impacts of reform.

2.31. We assessed the options using the same principles-based approach, differing only in the way fairness is applied because these issues do not relate directly to different treatment of end consumers.³¹ The wider systems analysis provided potential consumer and system costs and/or benefits of these options to support the principles-based assessment.

2.32. The following chapters explain how we have used this approach to reach our final decision, both for residual charges and Embedded Benefits. Then we discuss the wider systems modelling and the potential impacts of these reforms on the wider system, before explaining when the reforms will be implemented and the next steps to be taken.

SCR process

2.33. We have decided to implement these reforms using a 'type 1' SCR. This means that we will set out our decision for each aspect of the SCR. We will direct industry participants to raise modifications which give effect to our decision. We have set out high level principles which the modifications raised must meet, specific details which the original modification proposal must include, and where appropriate other aspects where industry must develop suitable proposals.

2.34. We have set clear expectations as to when we expect modifications to be implemented. We expect to work with modification proposers to ensure modification development timetables are set in order to provide us with the detailed modifications for approval in time for implementation as set out in Chapter 6.

³⁰ <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 5 - reform to non-locational embedded benefits.pdf</u>

³¹ As previously explained 'We think that reasonable treatment of industry parties is appropriately covered under our 'reducing distortions' principle, which will facilitate a level playing field between competing network users, and under proportionality and practical considerations, which includes consideration of the potential effects of material changes to charges'. This is discussed further in the TCR working paper at

https://www.ofgem.gov.uk/system/files/docs/2017/11/tcr working paper nov17 final.pdf

2.35. Finally we will work with industry to ensure cross-code dependencies are factored into the modification development process.

3. Decision on Residual Charges

Chapter summary

This chapter describes our decision and approach to reforming residual electricity network charges. Following feedback from stakeholders, we have decided to implement a refined version of the fixed charges we consulted on 03 September 2019. This will introduce one charging band for domestic consumers and a series of charging bands for non-domestic consumers.

We recommend this chapter is read in conjunction with two other chapters of this document - "Our approach" and "Quantitative analysis of our reforms".

Introduction

3.1. There are currently two types of electricity network charge – forward-looking and residual charges. Forward-looking charges reflect how users contribute to future network costs by using networks at a particular time or in a particular location. Residual charges are determined once the forward-looking charges have been calculated, to recover the remaining "allowed revenue" set under our price controls - the costs of investing in and operating the networks. These residual or 'top-up' charges are significant, currently accounting for around £4bn/year across electricity transmission and distribution networks (around 10-15% of a typical electricity bill).

3.2. The forward-looking and residual charges are calculated separately for distribution and transmission use of system charges. For distribution charges, each of the fourteen distribution licensed areas by the relevant DNO, while transmission charges are determined by the Electricity System Operator (ESO) applying a single charging methodology for all three transmission licensed areas. Hence there are fourteen sets of distribution charges and a single set of transmission charges.

3.3. Our energy system is undergoing a radical transformation. We are generating and using electricity in different ways, in different locations and at different times. To facilitate the energy transition we are working to create a smarter, more flexible energy system. The TCR aims to ensure that all demand users pay a fair share of residual charges towards the costs of the networks. Left unchecked, the current system could leave those who cannot

afford or are otherwise unable to invest in smart, flexible energy solutions bearing a greater share of network charges over time.

3.4. Changes in network use and technology have meant that the existing residual charges have created distortions, which allow some consumers (those with generation on their premises, for example) to reduce their contribution to these costs. These distortions are likely to increase over time. They have two effects:

- **first**, charges increase for other consumers to make up for lower overall revenues recovered from those users eg with on-site generation; and
- second, they encourage consumers to invest in technology or change their behaviour in ways which may increase rather than decrease the total costs of the system.

3.5. The current approach to residual charges can distort both investment and operational decisions, increasing costs for consumers in general. Our reforms seek to minimise distortions affecting competition between different kinds of network usage, including generation, storage and demand response, arising from residual charges.

The decision-making framework

3.6. As part of the SCR, we have carried out a principles-led assessment, setting out three guiding principles to inform our assessment – reducing harmful distortions, fairness, and proportionality and practical considerations. The principles and their application to reforming residual network charges have been considered in the context of ensuring that we act in accordance with our principal objective and statutory duties.³²

3.7. We provided detail on these principles in our SCR launch documents and Annex 1 to our minded-to decision. We summarise our interpretation of these principles in our decision section below.

³² We note that our final decision on whether the modification proposals raised should be implemented will be based upon: whether the proposal better facilitates the achievement of the relevant code objectives, compared with current arrangements, and whether the proposal is consistent with our wider statutory objectives and duties, including those under European law.

3.8. We have also carried out modelling to support our assessment. We commissioned consultants to undertake wider system analysis to examine the implications of reforms to residual charges at transmission and distribution level. They assessed the level of expected consumer and/or system benefits when compared to the existing arrangements. We also tested sensitivities for different Future Energy Scenarios and the size of the overall residual charges. We also looked at the estimated charges and resulting distributional effects. Further detail is set out in chapter 5 'Quantifying the benefits'.

3.9. This analysis indicated a strong long-term case for reform of residual charges. Our reforms to residual charging are projected to result in £0.5bn to £1.6bn of consumer benefits to 2040. The system benefits are even larger, ranging from £0.8bn to £3.2bn. These estimates include the range of benefits if the total residual charges increase or decrease by 50%.

3.10. This section should be read in conjunction with Chapter 5, Quantifying the benefits, and the Impact Assessment, published alongside this document, which provide further detail on our assessment framework.

Consultation on our minded-to decision

Proposals

3.11. In our 2017 working paper, we expressed our view that residual charges should be levied only on final demand customers, and not on generation connected to the system.³³ On 28 November 2018, we confirmed our minded-to view was that all final demand consumers who benefit from the electricity network should pay towards its upkeep in a fair manner, noting storage facilities are intermediate users of electricity which store electricity for later consumption.³⁴ We considered that residual charges should be paid by final demand consumers to reduce the potential for distortion and improve competition between different types of generator.³⁵ We also identified practical challenges in establishing a level

³³ https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-update-approach-reviewing-residual-charging-arrangements

³⁴https://www.ofgem.gov.uk/system/files/docs/2018/11/targeted_charging_review_minded_to_decisi on_and_draft_impact_assessment.pdf

³⁵ In our minded-to consultation, we said that final demand users are end consumers who use the electricity supplied by electricity networks, whereas storage facilities are intermediate users of electricity which stores electricity for later consumption.

playing field in applying residual charges between different types of generator, and noted that recovery from final demand would be a relatively low change approach.

3.12. In our minded-to consultation, we sought stakeholder views on our proposals for reforming residual charging arrangements. We consulted on two leading options for reform:

- A fixed charge which we said was our preferred option, where the total applicable allowed residual revenue for transmission and for each licensed distribution area is apportioned to voltage levels based on total users' contribution to net volumes on the relevant network, and then further to user segments within each voltage level, to calculate a single, fixed charge for all users in each segment. We proposed to segment users through an existing industry classification Line Loss Factor Classes (LLFCs).³⁶ For non-domestic users, this involved segmenting users into 11 LLFCs across the low voltage (LV) and high voltage (HV) distribution networks, with separate charges for users connected to the extra high voltage (EHV) and transmission networks. For domestic consumers, this included differentiating between those consumers with and without Economy 7 meters. We proposed that, as Economy 7 users are treated differently in current industry arrangements, and *as a group* use a higher amount of energy on average, this could be a basis for different residual charges. We noted there was a strong theoretical basis for fixed charges, as they cannot be easily avoided other than by disconnecting from the grid.
- An agreed capacity charge, where the total allowed residual revenue for transmission and for each licensed distribution area is first apportioned to voltage levels based on total users' aggregate capacity on the relevant network, and then a charge per unit of capacity is calculated, with larger users' charges based on their agreed capacity level and smaller users (for whom this data is not available) charged on a "deemed" or assumed capacity level.³⁷ We noted, as these charges are

³⁶ Line-loss factor classes are a collection of metering systems with the same line loss factors. The line loss factors indicate the user's location on the network and metering characteristics. We clarified in our open letter in June 2019 that by LLFCs in our minded-to decision, we were referring to those LLFC groupings that aligned with the industry-wide distribution use of system charging (DUoS) tariff groups. https://www.ofgem.gov.uk/publications-and-updates/future-charging-and-access-programme-consultation-supplementary-analysis-november-2018-minded-decision-targeted-charging-review

³⁷ We estimated three potential 'deemed' capacity levels for low, medium and high using domestic consumers and one deemed level for small business customers without an agreed capacity.

based on capacity, there could still be some scope to take action to reduce contribution to residual charges.

3.13. The three steps of allocating residual charge, segmenting users and calculating charges for each of these options are summarised in Table 1 below.

Minded-to decision – summary of leading options						
Option Residual charge allocation		Segmentation approach	Charge calculation			
A fixed	Applicable residual	Consumers connected at	Residual charges for			
charge –	charges for	each voltage level are	each consumer			
our	transmission and	segmented further into	band are divided			
preferred	each licensed	bands based on LLFCs. The	equally among all			
option	distribution area are	residual charges for each	users in that band			
	allocated to the	voltage level are allocated to	– so all			
	different voltage levels,	customer bands based on	consumers in a			
	according to the total	total net consumption	band pay the			
	net consumption	levels for all consumers in	same fixed charge			
	volumes of all	each band.	(within each			
	consumers at each		distribution licensed			
	voltage level.		area).			
An agreed	Applicable residual	N/A	Residual charges for			
capacity	charges for		each voltage level			
charge	transmission and	(a linear capacity charge, so	are divided			
	each licensed	no further user segmentation	equally among			
	distribution area are	required).	units of capacity in			
	allocated to the		that band - all			
	different voltage levels,		users in a voltage			
	according to the		level pay the			
	aggregate capacity of		same charge per			
	all consumers at each		unit of capacity			
	voltage level.		(within each			
			distribution licensed			
			area).			

Table 1 summary of leading options from minded-to consultation
3.14. We assessed the leading options against our three TCR principles, discussed further in Chapter 2 - Our approach. We also considered the distributional impact of our options, particularly considering fairness for to all consumers, including those domestic consumers in vulnerable situations. Our distributional modelling assumed that charges to suppliers are fully and directly passed through to consumers. We expect the pass-through of benefits from suppliers and generators to consumers to be high over the timescales in question, though we recognise that specific changes to charging structures may not always be directly reflected in tariffs.

3.15. The fixed charge option which we preferred has a strong theoretical basis. Of the leading options we considered, we think it is the least avoidable, minimising harmful distortions.³⁸ Similar approaches have been adopted in other countries.³⁹ We said both equity and equality were important aspects of fairness and a fixed charge combines equality among users within bands and equity between them. Participants in our earlier Consumer Panel also responded favourably to the underlying justification of a fixed charge option, as well as models where contributions were linked to usage.⁴⁰ Our other leading option - an agreed capacity charge - had more equity for larger users, with a user's charge rising with their capacity, providing greater differentiation between different users, though with lower equality.

3.16. In our minded-to consultation, we proposed that LLFCs should be used to segment users connected at high voltage (HV) and low voltage (LV) on the distribution networks under our preferred option of a fixed residual charge. We sought views specifically on how these segments were set and whether LLFCs would be a sensible way to segment residual charges, including whether further bands were needed for some users.

 ³⁸ The MIT Utility of the Future report suggested residual charges should be recovered in a minimally distortive manner and considers a fixed charge approach – further detail is available here: https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf We also conducted research with large users, published alongside our minded-to consultation. It identified a number of factors which would impact large users' decision-making, when considering reducing their capacity: https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 6 - large users.pdf .
 ³⁹ California introduced a fixed charge, while Nevada is increasing the fixed element of its charge and the Netherlands have brought in a fixed charge linked to physical capacity, while Spain introduced a gross consumption charge for new solar installations.

⁴⁰ Ahead of our minded-to decision we held a consumer panel to explore consumer views on fair recovery of residual charges. The report can be accessed here:

3.17. We also outlined our assessment against our three principles of reducing harmful distortions, fairness and proportionality and practical considerations. These assessments have since been updated based on stakeholder feedback as outlined in the section below.

3.18. We commissioned consultants to conduct wider systems analysis to model the potential changes to the electricity system as a whole, considering different potential energy futures, without and with our reforms in place.

Stakeholder views – minded-to consultation

3.19. We value the expertise and views of each stakeholder. Since the minded-to consultation closed, we have carefully reviewed all responses. We have also engaged stakeholders through the Charging Futures Forum, webinars, podcasts and numerous bilateral meetings.⁴¹

3.20. Many respondents agreed with our approach, that a fixed charge would best meet our overarching TCR principles. Respondents considered that it had the merits of simplicity and predictability, whilst providing stable revenue recovery and removing distortions. Some stakeholders supported our view that it would achieve a positive balance of equality within charging segments and equity across segments. Others argued that an agreed capacity charge was fairer as it was more equitable to all network users. Similarly, some stakeholders called for greater granularity, particularly for non-domestic consumers due to the broad range and profiles of users within each segmented band. Please see the accompanying summary of responses document for a detailed overview of consultation feedback, published alongside this decision.⁴²

3.21. Key comments and suggestions made by respondents included:

 Domestic consumers – A number of respondents said that it was unfair to treat single-rate and two-rate (Economy 7) domestic users differently, with some respondents seeing little reason for them to be treated differently. There was also concern our policy would fail to differentiate between different types of domestic users, in particular users on low incomes. Some stakeholders noted that that there

⁴¹ http://www.chargingfutures.com/

⁴² The summary of responses to our minded-to consultation is published alongside this document.

was a link between low income and low consumption and suggested that fixed charges might therefore disadvantage some vulnerable users.

- Deemed capacity Some stakeholders supported deeming (providing an assumed level of) agreed capacity for small users, considering this more equitable. Others noted that the deeming of an agreed capacity would cause a greater risk of manipulation or mistakes leading to specific customers under or over-paying their share of charges. They noted limitations of currently available industry data which may make this option harder to implement fairly and accurately.
- Small and Medium-sized Enterprise (SME) and large users A number of respondents expressed concerns with the level of segmentation, particularly in relation to SMEs and large users. Some thought that the level of segmentation based on LLFCs was insufficient and needed more granularity within segments to avoid inequality between larger and smaller users, especially those connected at low voltage, high voltage and extra high voltage (EHV). Some respondents suggested LLFCs were too arbitrary in their segmentation of users.
- **Hybrid approach** Some respondents suggested a hybrid approach, with an agreed capacity charge for larger users, and fixed charges for smaller users.
- Final demand There was widespread support among respondents for our proposal to apply residual charges to final demand only. A number of respondents requested further clarity around how our proposal to charge final demand customers would be applied in practice.

3.22. Respondents generally supported the rigorous approach we took to the wider systems modelling.

3.23. In June 2019, we published an additional consultation on supplementary analysis on our minded-to decision.⁴³ In this consultation we clarified an aspect of our minded-to residual policy proposals in relation to the use of LLFCs and invited stakeholders to provide

⁴³ <u>https://www.ofgem.gov.uk/publications-and-updates/future-charging-and-access-programme-</u> <u>consultation-supplementary-analysis-november-2018-minded-decision-targeted-charging-review</u>

any further comments, if they considered it affected their previous response.⁴⁴ Ten respondents commented on this point but none considered it changed their previous response or should change our view.

September 2019 consultation on refined approach

3.24. As described above, we proposed two leading options for reform of residual network charges in our minded-to decision and said we preferred a fixed residual charge. Most respondents to our consultation who expressed a view on our minded-to proposals supported a fixed residual charge approach, but a number raised concerns about aspects of the specific proposals.

3.25. Some respondents felt fixed charges should take more account of the diversity of non-domestic users, noting that these users spanned a broad range of sizes within a given band. Some also thought aspects of our proposed basis for segments could be seen as arbitrary.

3.26. We recognise respondents' views that there should be more granularity in some non-domestic user segments, to differentiate between different users groups. We also understand there can be historic reasons for users falling into certain LLFCs, with users in different categories overlapping in their usage characteristics, which may be seen as arbitrary as a basis for setting charges. Having reflected on these responses, we considered how to adapt the fixed charge option, with refined segments for non-domestic users at each voltage level, in place of using LLFCs. We published an open letter for consultation on 3 September 2019 to gain stakeholder views on these updated proposals for non-domestic consumers, as set out below: ⁴⁵

• A refined banded fixed charge: we outlined proposals for a fixed charge with a refined set of bands for non-domestic consumers. We proposed the introduction of more segments for non-domestic consumers, to address the significant variation in these customers, reflecting the views of many consultation respondents that

⁴⁴ We clarified in our open letter in June that by LLFCs in our minded-to decision, we meant were referring to those LLFC groupings that aligned with the industry-wide DUoS tariff groups. https://www.ofgem.gov.uk/publications-and-updates/future-charging-and-access-programme-consultation-supplementary-analysis-november-2018-minded-decision-targeted-charging-review https://www.ofgem.gov.uk/publications-and-updates/future-charging-and-access-programme-consultation-refined-residual-charging-banding-targeted-charging-review

greater granularity was needed. We said we still considered fixed charges would be the least avoidable and had a strong theoretical basis. We also said that domestic consumers should be treated separately from non-domestic users due to their different characteristics. We indicated that we were considering the approach to segmentation of domestic consumers under a fixed charge option, including the combination of all domestic customers into one charging band.

• A hybrid fixed-agreed capacity charge: we also considered a hybrid charge, similar to that suggested by some respondents. This would comprise a fixed charge for smaller users with agreed capacity charges for larger users.

3.27. These options are summarised in Table 2 below.

Table 2 Summary of refined approaches for non-domestic consumers – September 2019 open letter

Option	Residual charge	Segmentation	Charge calculation
	allocation	approach	
Refined	Applicable residual	Consumers connected at	The allocated proportion
banded	charges for each	each voltage level are	of the residual charges
fixed	licensed area are	segmented further	for each consumer band
charge	allocated to the	into bands based on	is divided equally
	different voltage levels,	the distribution of	among all consumers in
	according to the total	consumers in the	that band - all
	net consumption	population at each	consumers in a band
	volumes of all	voltage level. The	pay the same fixed
	consumers at each	residual charges for each	charge (within each
	voltage level.	voltage level are	licensed area).
		allocated to customer	
		bands according to the	
		total net consumption	
		volumes for all	
		consumers in each band.	
Hybrid	Applicable residual	For large users - N/A -	The allocated proportion
fixed-	charges for each	a linear capacity charge	of residual charges for
agreed	licensed area are	is calculated, so no	consumers with agreed
capacity	allocated to the	further allocation to	capacity charges is
charge	different voltage levels,	bands required.	divided equally on the
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Open letter – summary of refined approaches

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Option	Residual charge allocation	Segmentation approach	Charge calculation	
(combining an agreed capacity charge for large users and a fixed charge for small users)	according to the total net consumption volumes of all consumers at each voltage level.	Small users are further segmented into bands.	basis of units of capacity at that voltage level - all consumers pay the same per unit capacity charge in each voltage level (within each licensed area). Residual charges for each consumer band are divided equally among all consumers in that band - all consumers in a band pay the same fixed charge (within each licensed	

3.28. For non-domestic customers, we explained how we intended to set the bands for the refined fixed charge, establishing criteria based on the TCR principles, and how these criteria would guide the periodic review and updating of bands, as shown in

3.29. Figure 3 below.

Figure 3 Applying TCR principles to non-domestic customer segmentation for refined fixed charge

Reducing harmful distortions	 Lowest number of segments needed to objectives Segments avoid splitting dense clusters, of similar user types where possible Sufficient users per segment to avoid gaming, volatility and commercial considerations (such as the confidentiality of EDCM charges)
Fairness	 Broadly consistent upper limit on range of user types facing the same charge across segments Segments well balanced with a broadly consistent basis, aiming to distinguishing user groups with significantly distinct characteristics, or clear reasons for differences. Tangible, justifiable link to energy usage in the basis for segment boundaries
Practicality and proportionality	 Lowest number of segments necessary to achieve objectives Broadly consistent basis for segments for simplicity Uses available data and any system changes are proportionate Distributional effects and complexity are no greater than necessary to achieve objectives

3.30. Applying the criteria outlined in

3.31. Figure 3 to distribution charges, we identified five charging bands for each of LV, HV and EHV non-domestic consumers. While the band thresholds would be the same for HV and EHV customers under this proposal, their share of the residual charges would be calculated at voltage level, resulting in 15 non-domestic fixed charges for each of the 14 distribution licensed areas.

3.32. We considered whether to segment transmission-connected customers, and concluded that further segmentation would not be required. Consumers connected to the transmission network were thought to span around one order of magnitude range in size - less than other groups.

3.33. We suggested these charging bands might need to be evaluated for each distribution licence area to ensure that the segments did not have too few customers. We were concerned in particular that small customer numbers could have implications for commercial confidentiality or undue volatility of charges. We set out key steps to designing bands which meet these criteria. We published indicative charges for the North East distribution region to provide stakeholders with an example of the potential impacts of these charging reforms. We provided charges for our indicative region to facilitate stakeholders' ability to consider the potential impacts of the policy and compare it with the other options considered. The purpose of the consultation was to provide sufficient information to obtain views on the proposed policy rather than provide a full breakdown of

potential charges across all DNO areas.46

3.34. We also set out further detail on aspects of our proposals. We indicated that:

- Arrangements would need to differentiate between domestic and non-domestic users, with distinct arrangements for unmetered customers, with residual charges allocated to these groups separately, within a voltage level, before any further segmentation is applied.
- By final demand, we explained that this meant electricity which is consumed other than for the purposes of generation or export onto the electricity network. In practice, this would exclude electricity imported from the grid which is necessary for the operation of generation or, in the context of storage, which is imported for the purposes of re-exporting, including any which may be lost through waste in doing so.
- We confirmed that we considered a fixed residual charge should be applied on a per site basis as is currently the case for both CDCM and EDCM models.⁴⁷ We had indicated this in the minded-to consultation and clarified further at the January Charging Futures Forum. We recognised that multiple meter points (known as MPANs) can sometimes be associated with a single site.⁴⁸ In general, we said it was not our policy intention to apply multiple fixed charges to single sites.
- We proposed that neither the refined options presented nor those in our minded-to consultation would apply to unmetered customers. We proposed that the residual charge apportioned to this group of customers would continue to be charged on the same basis as today, using profiled consumption volumes.

3.35. We also said we expected many other aspects of how the charges would be set would be consistent with existing arrangements, although it would be for industry to consider consequential changes which may be needed to industry processes or codes

⁴⁶ Charges will be indicative until the open industry process has developed the detailed code modifications.

 ⁴⁷ The Common Distribution Charging Methodology (CDCM) and EHV Distribution Charging Methodology (EDCM) are the distribution use of system (DUoS) charging methodologies which apply for customers connected to the the LV / HV and EHV distribution networks, respectively.
 ⁴⁸ Each point of entry or exit to the distribution system has a metering point, with an associated

administration number (MPAN). There may be multiple metering points on a single site.

through the modification process. We indicated we would expect that some form of revenue reconciliation is likely to be needed and said we expected it was likely to make sense to apply the fixed charge pro rata on a daily rather than yearly basis to account for changes within year. We indicated we expected these matters to be developed further by industry in the most appropriate way through the modification process.

Stakeholder views on September 2019 open letter

3.36. We received 50 responses to the September 2019 consultation. We have carefully reviewed all responses and engaged stakeholders further through the Charging Futures Forum, workshops and numerous bilateral meetings.⁴⁹

3.37. Overall, while many respondents recognised the intent behind the new proposals to increase equity in a fixed charge, and a few were in favour of the new proposals, the majority of responses received did not support the refined proposals. A number of respondents did not prefer the refined proposals to the original minded-to proposals, while some respondents believed that the refined proposals did not better meet the TCR principles than the original proposals. Some considered the proposed segmentation methodology would create further distortion and practicality issues and costs. Some respondents also noted that they expect significant increases in the charges for some users.

3.38. Key comments and suggestions made by respondents included:

- **Equity / equality:** We took into consideration the feedback we received after the minded-to consultation and proposed a refined option that would increase equity and equality. A number of respondents recognised the intent of this aim, which some explicitly supported.
- Refined fixed charge banding implementation: Some respondents raised concerns about the complexity of the proposed banding. Some respondents suggested that such a solution would require changes to systems or data arrangements and that the methodology on customer allocation needed to be clear for the industry to administer. There were also concerns about reallocation between

⁴⁹ http://www.chargingfutures.com/

bands and consumers remaining in the same band for five years, regardless of their potential usage changes.

- **Refined fixed charge banding principles:** A number of respondents welcomed the intent behind the refined proposals but felt they did not better meet the TCR principles. Specific comments included:
 - Reducing harmful distortions: some respondents suggested that further distortions would be created through introducing the proposed bands, while a few highlighted that an agreed capacity charge would also involve some harmful distortions. A few stated that an LLFC option would create less distortion, whereas others supported segmentation by consumption levels instead of LLFC, stating that this would create less distortions. Some respondents were concerned that there might be a risk of gaming when allocating consumers to bands, and monitoring may be needed. The concern was also raised that the reforms could impact nascent flexibility markets, noting flexibility will be beneficial in supporting decarbonisation.
 - *Fairness:* a few respondents noted that the refined proposals would negatively impact certain sectors more than others. Some respondents raised concerns on the fairness of the bands both for domestic and large consumers. Some respondents felt that assigning domestic consumers to bands would not take into consideration their characteristics, therefore this could be unfair for vulnerable groups. A few respondents considered the boundary effects created by proposed banding would be unfair. Fairness concerns included the potential for differences in charge based on structures across sites, charge differences between users immediately either side of a boundary and that some users would have greater potential to avoid charges than others.
 - Proportionality and practical considerations: Some respondents raised concerns that the required data to determine the bands is not currently available to network operators and system changes would have associated costs. Several noted their preference for an option that uses existing dataflows. Some emphasised an LLFC option would be more practical to implement, though several still did not support this option. One respondent emphasised that practicality was not sufficient reason to adopt a solution. A few respondents suggested that banding methodologies were not sufficiently

clear. Some respondents were concerned their charges would increase substantially, which they considered to be disproportionate.

- Agreed capacity-fixed hybrid charge: some respondents provided views on potential alternative solutions. Several stated a preference for an agreed capacity-fixed hybrid charge, involving agreed capacity charges for larger users and fixed charges for smaller users. Others suggested a blended combination of volumetric or agreed capacity charges with a fixed charge, which they considered would achieve similar outcomes more simply and with lower practical requirements.
- Split between consumers with and without an agreed capacity: Some respondents noted that some customers connected at LV, with Current Transformer meters, have agreed capacities. They suggested we should apply charges based on agreed capacity for all user groups with this data, rather than HV and above as we had originally proposed.
- **Approach to domestic consumers**: Some respondents expressed concerns about the banding of domestic consumers, as well as the impact on vulnerable consumers. Some, including consumer representatives, welcomed the fact that we were considering no longer separating between Economy 7 and single-rate consumers.
- Final demand, complex sites and unmetered supplies: Some respondents felt further clarity was needed on what is meant by 'final demand', to ensure that charges for complex sites are calculated correctly and applied fairly. Some respondents emphasised charges should account for unlicensed generation and onsite generation or storage, while others raised practicality concerns relating to how this demand would be identified. One respondent noted the wide diversity of unmetered customers, noting any averaging would significantly impact those at the extremes. Another supported retaining the existing charging basis for unmetered customers.
- **Implementation timing, cost and approach:** A number of stakeholders indicated they would prefer implementation in 2023, citing links with access reform and the need to provide sufficient notice of changes for suppliers and network users to adjust. Some respondents raised concerns about the cost and complexity of the required changes and how that could affect implementation timeframes.

• **Consultation process:** A number of respondents felt that the consultation period was too short and that the open letter did not provide enough detail on potential future charges for them to assess the impacts of the proposals, particularly where users had sites in other distribution network operator regions.

Our decision on residual charges

3.39. Since our consultation closed, we have carefully considered responses received and engaged further with stakeholders. A number of respondents recognised the aims of our updated proposals, in increasing the level of equity from our minded-to fixed charge option. Some explicitly supported this aim, although many disagreed with our proposed charge.

3.40. Stakeholders have a range of views on the appropriate balance of our principles and what constitutes a fair outcome. Many have a strong preference for simplicity and practicality, though others noted what mattered was the overall cost-benefit assessment. Many also highlighted concerns that banding could result in distortions, though some also recognised some degree of distortion would exist under any approach to residual charging, notably an agreed capacity or volumetric charge. There were strong concerns from some larger users in particular about the degree of change in their charges and the fairness and proportionality of these changes.

3.41. We note many large users who are able to take action to avoid Triad periods will pay very low charges today. Residual charges allocate a fixed amount of revenue to be collected and taking action to avoid them will only increase costs for other users. It is consistent with the aims of our policy for these consumers to make a fair and increased contribution to residual charges, which will involve substantial increases for some. In seeking to increase equity from our original proposals, given concerns that charge increases could be inequitable and disproportionate for smaller users under our minded-to fixed charge proposal, this also implies a larger share of contribution made by larger users, reflecting their greater usage. But we have also been mindful of the need for some equality in charges and to ensure the overall impacts of our reforms are proportionate.

3.42. While a number of respondents did suggest alternative options or adjustments there was not a clear consensus in support of a single approach. We have considered how our minded-to proposals and the proposed fixed banded approach could be adapted, or potentially combined, to perform better against our principles, and identified simplifications to our proposed approach, drawing on the suggestions made by respondents. We outline our assessment and decision in the sections which follow.

Summary of our assessment

3.43. We continue to be of the view that residual charges should be allocated between users at different voltage levels and to different segments for those connected to distribution networks based on net volumes. We think this tangible basis in energy usage provides a strong justification, consistent with our principles and has relatively lower distributional effects overall compared with other options we assessed during the process. We note the lack of alternative datasets which exist for all customers. We recognise some larger users would face a somewhat greater share of residual charges than today.

3.44. We also continue to believe that further segmentation of users is needed to increase the equity of charges for those connected to the distribution network. Under our minded-to proposal, a large range of users of different sizes in a single LLFC would face the same fixed charge, which we do not consider performs well under our fairness principle.

3.45. **Domestic consumers**: We have concluded that an agreed capacity residual charge is not desirable for small users who do not have an agreed capacity level, given the lack of available data on which to base these charges. We think a fixed charge better meets our principles for these users. We also consider that domestic consumers should not be charged separately to one another based on their usage, given their otherwise similar characteristics. We have decided that a single fixed charging band for all domestic consumers best meets the principles we have used.

3.46. **Non-domestic consumers:** For larger users for whom agreed capacity data is available, an agreed capacity charge would be simple to implement. But it has low levels of equality and would result in significant increases in charges for the largest consumers, potentially involving annual residual charges up to several £million based on charges for our illustrative North-east region. As noted above, we also agree with concerns about deeming agreed capacity for smaller non-domestic users. We therefore consider that an agreed capacity charge performs less well than others against our fairness and proportionality principles. We have not identified suitable variants which would sufficiently mitigate these impacts while performing better against our principles overall. We therefore consider a banded fixed charge better meets our principles for non-domestic users, with some adaptations from our consultation proposals, to simplify the banding approach and address other concerns raised by respondents.

3.47. For the reasons set out here and below, we have therefore decided to implement a refined version of our banded fixed charge. Where users have agreed capacity data, this

will form a less avoidable basis for segmentation and should be used to define bands, while net consumption volumes are a justifiable basis on which to segment those users who do not. We agree with those respondents that suggested user groups connected to the LV network who have an agreed capacity should also be segmented on this basis, rather than volumes.

3.48. We recognise a banded fixed charge will be somewhat more complex to implement than our other leading options. We have engaged further with stakeholders on practicalities through the consultation process, to better understand the scale of any changes needed to data or systems, and any aspects of the approach which would benefit from simplification. We have not received evidence to suggest the proposal cannot be implemented, although some respondents highlighted the extent of these modifications and challenges, nor that the costs would be such as to outweigh the benefits of reform. In our decision, we have simplified the design of the banding. We consider that industry will have scope to develop a suitable approach to implementation which builds on existing systems in a proportionate way.

3.49. We outline the details of our decision below, and explain our assessment in further detail. We also present illustrative charges for the options we have considered, including our final decision. A complete set of final charges (based on available information ahead of the charging year) across DNO regions will form part of further consultation as the detail of reform proposals is more fully developed through the industry modification process.

Our decision

3.50. Our final principles-based assessment, which reflects feedback and evidence provided, supported by our analysis, has led us to decide to implement a fixed residual charge for final demand consumers only, with distinct arrangements for unmetered sites. In summary, these fixed bands will include a single fixed charging band for domestic consumers and a series of fixed charging bands for non-domestic customers:

- For **domestic consumers**, there will be a single transmission residual charge, and a single distribution residual charge within each of the 14 distribution licensed areas. So all domestic customers within each of 14 distribution areas will pay the same level of residual charge.
- For **non-domestic consumers**, there will a single set of transmission residual charges, and a set of distribution residual charges for each of the 14

distribution licensed areas. for each fixed charging band. Bands will be defined by a consumer's voltage level and, where further segmentation is required, further boundaries will be defined based on agreed capacity for larger consumers for whom this data is readily available, and net consumption volume for smaller consumers for whom this data does not routinely exist.

3.51. Charges for unmetered customers will be derived considering their net consumption volume or agreed capacity, on the basis of their 'profiled' demand and the applicable charging model.

3.52. For the avoidance of doubt, where we refer to residual charges in this decision, we are referring to both transmission and distribution residual charges, unless otherwise specified. As per today we would expect appropriate arrangements to prevent perverse incentives to hoard capacity or increase through negative charges. Currently, there is no distinct transmission demand residual calculated for demand customers who are charged on a non-half-hourly basis, as distinct from a forward-looking component of the charge. These reforms will require a residual charge to be applied to all demand customers, including non-half-hourly. The current transmission methodology uses non-half hourly tariffs to ensure revenues recovered match those set in the tariff model (to make sure each transmission demand zone pays the correct amount of revenue). This leads to a small difference in the treatment between half hourly and non-half hourly consumers in England & Wales and Scotland. Our consultants calculated the different residual charges which would be applicable if this allocation method was changed. The current modelled approach leads to similar residual charges under both methodologies. Given the limited impact of this anomaly, we suggest the ESO considers this further if it deems appropriate. The new transmission residual charges will be implemented in April 2021 and distribution residual charges in April 2022.

3.53. A Significant Code Review (SCR) requires modifications to relevant industry codes to be raised to give effect to the terms of the direction. We set out the principles of our decision on residual charging below(the "Decision Principles"), followed by the design parameters for the modification proposals (the "Design Parameters") . The Decision Principles and the Design Parameters shall collectively be referred to as the SCR Decision Principles and each modification that is proposed to implement the terms of the directions shall be required to meet the SCR Decision Principles.

3.54. The directions we have published alongside this SCR require NGESO and separately, the electricity DNOs (with section B of their licence in effect) to bring forward modification

proposals to the CUSC and DCUSA (and other industry codes as required) to give effect to this decision and the associated directions.⁵⁰ We expect them to do so in consultation with relevant industry stakeholders as appropriate.

Decision Principles

3.55. Reforms to residual charging should meet the TCR principles of reducing harmful distortions, fairness and proportionality and practical considerations, as outlined above and described further in Annex 1 to our minded-to decision. This includes but is not limited to the aspects outlined below, which should be a focus of the modification proposals. We note that in developing the code modification proposals, NGESO and the DNOs will also have regard to the need to better facilitate the relevant code objectives. This section outlines how we expect the Decision Principles to be applied by the workgroups, followed by the Design Parameters.

- **Reducing harmful distortions**: The TCR residual charging reforms aim to reduce the harmful distortions caused by the current residual charging methodology which encourages some network users to take measures to lower their contributions to residual charges. Changes should seek to reduce the potential for and impact of any harmful distortions introduced as a result of changes to the residual charging arrangements. Residual charges that cause network users to adjust their investments or operational decisions are distortionary and can lead to inefficient use of the networks. They have the potential to distort competition between different network users. As some network users avoid charges, this increases the charges to other network users, further distorting usage and investment. Any method of residual charging will lead to some distortions, but harmful distortions should be reduced as far as possible so that the energy system works efficiently and in the interests of consumers.
- Residual charges help to recover the costs of expenditure required to efficiently
 maintain and operate the national electricity network from which all connected
 users benefit. Where residual charges incentivise behaviour such as load reduction
 which reduces the share of charges paid for by that user, this results in an increase

 $^{^{50}}$ By network licensees, in this document, we are referring to NG ESO and /or the electricity DNOs with section B of their licence in effect and references to network licensees are to be construed accordingly. .

in the share to be paid by other network users. This in turn increases the incentive for other users, who then pay an increased proportion of the residual charge, to take action to reduce their charges.

- Harmful distortions can impede a level playing field for competition between network users and encourage users to invest in technologies to reduce their demand from the network, for example by generating electricity on-site. Such investment may only be economic when avoidance of residual network costs is taken into account, with the generation having no effect in reducing network or system costs. Residual charges based on a fixed or agreed capacity basis may incentivise users to reduce their agreed capacity or disconnect from the grid entirely.
- **Fairness:** all final demand users who benefit from the electricity network should pay towards its upkeep in a fair manner.⁵¹
- We established a set of five components of fairness for assessment of residual recovery options: equity and equality, simplicity, transparency, justifiability and predictability. Equity and equality are both important concepts, but ones where there is likely to be some tension between them, as a charge cannot be both completely equal and equitable unless all users are very similar to one another. Residual charging arrangements should include a balance of equality and equity.
- We consider fairness applies to, and among, end-consumers, including domestic and microbusinesses, large users, consumers in general and particularly consumers in vulnerable situations. This needs to take account of impacts on demand users who are more price-sensitive and less able to respond to any changes in the residual charges that they pay, particularly if charges increase, also considering distributional impacts, particularly on consumers in vulnerable situations. This also considers the wider implications of changes made to charges which affect the rest of the electricity supply industry and the environment.
- Charges should not discriminate unduly against any particular user of the network

⁵¹ Final demand users are end consumers who use the electricity supplied by electricity networks, whereas storage facilities are intermediate users of electricity which stores electricity for later consumption.

and should mean that users with certain similarities (for example, level of access to the network), pay similar levels of residual charges. If a means of revenue recovery results in actions by network users that do not add value to the system but significantly increase costs for some consumers, it is unlikely to be consistent with our principle of fairness.

- A fair outcome will be one that minimises the potential for the most harmful distortions in the long run, even if this comes with short-term consequences that are seen as unfair by some users. Justifiable, transparent and clear approaches can help ensure arrangements are seen as fair and acceptable for consumers.
- **Proportionality and practical considerations:** achieving changes in a proportionate and practical manner.
- Any proposals need to be proportionate to the issue being addressed, solutions should draw on existing data and systems where possible and involve proportionate changes to systems and charges.
- Proportionality considers whether a solution would deliver benefits through improving performance against the other TCR principles, and whether this could be done with minimum disruption for industry and the relevant stakeholders. If the same benefits of reform, considering performance against the TCR principles of reducing harmful distortions, fairness and proportionality and practicality considerations, could be delivered with lower disruption or at a lower cost, then it is likely to be a more proportionate response.
- A three stage test is to be applied considering: whether the measure is suitable to achieve the desired end, whether the measure is necessary to achieve the desired end, and whether the measure imposes a burden on an individual that is excessive to the objective sought to be achieved.
- Practical considerations include identifying the steps in the charging process which might have to change to implement our direction and to assess the potential cost of a policy change. A non-exhaustive list of aspects relevant to practical considerations include metering requirements, data collection, data processing, charge calculation, billing and calculation systems and settlement.

3.56. To some extent, the development of proposals will naturally involve balancing one or more principles. The ESO and the DNOs must be satisfied that, viewed in the round, the modification proposals that they bring forward under their respective Directions meet the Decision Principles, reducing harmful distortions against the status quo, recovering residual charges in a fair manner and in a way which is practical and proportionate. To build on the Decision Principles, we set out below Design Parameters which the modification proposals put forward by the licensees must be consistent with.

Design Parameters

Allocation of residual charges

- 1) Residual charges are to be applied to demand customers only and to all sites with final demand.
- 2) Distribution residual charges are to be apportioned as they are today between EDCM and CDCM customers as per the applicable charging model.
- 3) Following apportionment, all applicable distribution and transmission residual charges are to be allocated to users connected to each voltage level across the system (LV, HV, EHV and, for transmission residual charges, transmission voltages) on the basis of the aggregate net consumption volumes of those network users in each charging year connected at each voltage level.
- 4) Residual charges are subsequently to be further allocated to applicable customer segments as defined below, with distinct arrangements for unmetered customers.
- 5) The level of the charge for each segment will be calculated annually, in line with the current approach, to recover remaining allowed revenue once the forward-looking charges have been applied.

Residual charging structure and user segmentation

6) Residual charges are to differentiate between domestic and non-domestic consumers.

- Residual charges are to be structured as a set of fixed charges with a single fixed charge applicable to each charging band, with distinct arrangements for unmetered supply consumers.
- 8) **Domestic consumers:** All domestic consumers will be allocated to a single fixed charging band. There will be a single transmission residual charge, and a single distribution residual charge within each of the 14 distribution licensed areas. So all domestic customers within each of 14 distribution areas will pay the same level of residual charge.
- 9) Non domestic consumers: All non-domestic consumers will be allocated to one of a set of charging bands. The boundaries of the charging bands, and individual customers' allocation to them, will be reviewed and updated as needed in order that the required changes come into effect in line with the start of each new transmission price control. The reviews of the charging bands shall be based on the SCR Decision Principles.
- 10)Any need for consequential changes to other aspects of existing charging arrangements must be considered in developing code modification proposals to give effect to this decision (and associated Directions). Consequential changes to existing industry arrangements should be minimised, to the extent consistent with these Decision Principles and ensuring that they will not compromise the ability of network licensees to discharge their respective statutory duties to develop and maintain an efficient, co-ordinated and economic system of electricity transmission or distribution and to facilitate competition in the supply and generation of electricity.⁵²

Specific requirements of our decision

3.57. The network licensees must bring forward modification proposals which deliver the following specific requirements, as set out in the Direction published alongside this decision document -

1) **Final demand:** This must be defined as electricity which is consumed other than for the purposes of generation or export onto the electricity network. Generation

⁵² Section 9(1) and 9(2) of the Electricity Act 1989.

only and storage only sites will therefore be exempt from residual charges. An appropriate process must be established to assess and identify or, where a practical and proportionate approach cannot be identified, to robustly estimate final demand for the purposes of residual charging.

- Domestic consumers: There will be a single transmission residual charge, and a single distribution residual charge within each of the 14 distribution licensed areas. All domestic customers within each of 14 distribution areas will pay the same level of residual charge.
- Non-domestic consumers: residual charges for non-domestic consumers shall be on the following basis:
 - For transmission-connected consumers a single fixed transmission residual charge;
 - ii) For distribution-connected consumers a charging structure which combines a single fixed transmission residual charge and a single fixed distribution residual charge in each of four fixed charging bands **for each** of the following distribution-connected groups, for all consumers except unmetered supplies:
 - a) EHV-connected consumers;
 - b) HV-connected consumers;
 - c) LV-connected consumers with an agreed capacity as the basis for their current charge; and
 - d) LV-connected consumers without an agreed capacity.
 - iii) For consumers with unmetered supply a charge derived considering their net consumption or capacity, based on their profiled usage, as per the applicable charging methodology.
- 4) TNUoS residual charges: The ESO must establish a suitable allocation of transmission residual charges between customers charged on a half-hourly and non-half hourly basis as the basis for allocation. The total transmission residual is to be recovered from demand customers, apportioned between half-hourly charged

and non-half-hourly charged demand customers in proportion to their respective contributions to net consumption volumes.

5) Setting and allocating non-domestic consumers to bands:

- 6) Basis for residual charging band boundaries: The boundaries of the above bands will be set based on 40th, 70th and 85th percentiles of the number of relevant final demand customers in each of those categories on a GB-wide basis. These percentiles are to be determined by customer numbers on the basis of
 - increasing agreed capacity levels for customers connected to the EHV and HV distribution networks and LV customers with an agreed import capacity, and
 - increasing net consumption volumes for LV customers without an agreed capacity.
- 7) Setting and allocating consumers to residual charging bands: Boundaries are to be established by the network licensees on a consistent basis and users will be allocated to bands based on available industry agreed capacity where available, or net consumption data, as applicable. This is to be averaged over a period of no less than 24 months prior to the setting of the applicable residual charges, or longer if the requisite data can be made readily available at proportionate cost. ⁵³ For any customers for whom data cannot be made available for the period of 24 months, the process for New customers and customers lacking appropriate data below should be followed.
- 8) **New customers and customers lacking appropriate data:** A process shall be established to allocate customers for whom the requisite data is not available or available for a period of less than 24 months, such as new customers connected within that period, to the appropriate charging band, based on an assessment of their agreed capacity or consumption, as applicable. The process shall make use of such information as is available to best estimate the expected usage of the customer, eg by taking an average of all the data that is available, or based on an

⁵³ Based on data aggregation needs currently outlined in the Balancing and Settlement Code.

understanding from such sources as are considered appropriate of the typical profile of a similar customer, updating as needed.

- 9) Redundant connection capacity: The process for setting and allocating users to charging bands, for the purposes of calculating the level of fixed charge to apply to a site, should recognise circumstances where a customer retains connection capacity to a site for redundancy purposes only. Redundancy here refers to circumstances where a connection is unused other than when an alternative connection to a customer's site is unavailable. This must be clearly demonstrated, supported by documentary evidence to show that the capacity is not used in parallel with the other connection and the capacity of the primary connection(s) is / are not exceeded. In such cases, total consumption volumes across all connections should be combined for the purposes of allocation of residual charges. A process should be devised where this can be accounted for.
- 10) **Per site basis:** A fixed charge is to be levied on a single site basis. An appropriate definition of a site should be established. A proposed definition of a site which should be considered when formulating the proposal is as follows: "One or a collection of buildings, structures or pieces of land in close geographical proximity, owned or occupied by one customer within a defined curtilage on one site, where each building, structure or piece of land serves the other in some necessary or reasonably useful way."

In considering the need for any amendments to this definition of a "site", account should be taken of the CUSC, EDCM and CDCM definitions of a site, as well as wider industry terms which may be relevant to consider, including but not limited to premises as defined in the Electricity Act 1989, and Metering System as defined in the Balancing and Settlement Code.⁵⁴

In formulating a proposed definition for site regard will be had to the policy intent whereby a complex site with multiple connections or associated MPANs is not charged twice, operative sites are not unduly split, and the level of charges are based on capacity / usage at a site level, other than where redundancy provisions

⁵⁴ <u>https://www.elexon.co.uk/bsc-and-codes/balancing-settlement-code/,</u> <u>https://www.elexon.co.uk/bsc-and-codes/balancing-settlement-code/</u>

apply.

- 11)Review of charging band boundaries for non-domestic consumers: The boundaries of the charging bands shall be reviewed at such times as to ensure that the outcome of the review can be implemented at the same time as the next transmission price control takes effect. As part of each review, charging bands will be recalculated taking account of the SCR Decision Principles and percentiles established for banding. The review shall also be conducted so as to ensure a fair and proportionate progression of charges across bands, such as a limit of around an order of magnitude differential in charges between adjacent bands within a voltage level. Should agreed capacity or other capacity data becomes widely available for other LV user groups, bands will be reset at the next review on that basis. The first review of banding should have regard to the requirements in the paragraph below on First review of bands.
- 12) **Disputes:** An appropriate process shall be established to manage any disputes in relation to consumers' residual charges. Any process should be efficient and proportionate, using and, where necessary, build upon existing dispute processes in the relevant industry code as applicable. In developing the process, the network licensees must consider any data which may be needed to support this process and ensure the process has clear interfaces with such other processes as may be relevant

Aspects for network licensees to consider and develop

3.58. Network licensees, or the DNOs or ESO only where specified, must consider and seek to identify the most appropriate arrangements in relation to the following aspects and develop modification proposals consistent with the SCR Decision Principles set out above in relation to:

- 1) The frequency of the charge, considering a proposal of a p/site/day structure.
- 2) A mechanism for identifying which sites should be classified as final demand (as opposed to generation or intermediate demand) for the purpose of determining their applicable contribution to residual charges. An appropriate process must be established to assess and identify or, where a practical and proportionate approach cannot be identified, to robustly estimate sites with final demand for the purposes of residual charging. Industry should consider and build on thinking undertaken

through development of the proposed solution being considered under CMP280 and CMP281 and DCP341 and DCP342, as well as considerations under the approach developed by the Low Carbon Contracts Company (LCCC) when estimating charges for a CfD generator and work undertaken by Elexon and the LCCC on how to charge Final Consumption, as they consider relevant.⁵⁵ Where necessary, network licensees should also consider possible methodologies for robustly estimating sites with final demand, including potential numerical approaches such as considering the relative proportions of import to export at a site.

- 3) The approach to establishing appropriate and proportionate arrangements for residual charges for Independent Distribution Network Operator (IDNO) network customers, customers connected with private wires and complex sites, considering relative charging arrangements on IDNO networks and the customer's voltage of connection.⁵⁶
- The detailed design of systems and processes required in order to implement the solution set out in the modification proposals put forward to us for determination, considering
 - a) how existing industry systems may be adapted and centralised approaches may be utilised in establishing banding and allocating users to bands, where they would present the most efficient, robust and proportionate implementation solution, consistent with the SCR Decision Principles. This includes but is not limited to considering the role Electricity Central Online Enquiry Service (ECOES), the Data Transfer Network and Elexon / Balancing and Settlement Code (BSC) processes and systems, as well as the roles parties such as suppliers or their agents may play in a centralised

⁵⁵ Further information on these can be found at the following links:

https://www.nationalgrideso.com/codes/connection-and-use-system-codecusc/modifications/creation-new-generator-tnuos-demand-tariff,

https://www.nationalgrideso.com/codes/connection-and-use-system-code-

cusc/modifications/removal-bsuos-charges-energy-taken-national,

https://www.dcusa.co.uk/change/removal-of-residual-charging-for-storage-facilities-in-the-cdcm, https://www.dcusa.co.uk/change/removal-of-residual-charging-for-storage-facilities-in-the-edcm, https://www.elexon.co.uk/consultation/consultation-align-bsc-reporting-emr-regulations.

⁵⁶ IDNO revenues are governed by a Relative Price Control, which requires that DUoS charges for domestic customers connected to an IDNO network do not exceed the equivalent charges for the DNO within whose distribution area the IDNO is operating.

approach.⁵⁷ This should consider the need for appropriate governance arrangements if existing systems are adapted and used for a different purpose and take account of the need to ensure secure processing, transfer, storage and utilisation of data.

b) how the residual charging bands, and customers' allocation to these bands, are to be defined and communicated within industry systems and processes, including considering the potential to make use of updated existing categories such as introducing new LLFCs⁵⁸ on the basis of the banding we propose, or how other categories such as measurement class or point of connection, including voltage or substation could be used, where this can similarly support more efficient, robust and proportionate implementation, and better alignment with the SCR Decision Principles.⁵⁹

Specific alternatives for network licensees to assess

3.59. Through the consultation and assessment phases of the SCR, we have identified four specific issues which we believe merit further consideration. Accordingly, NGESO and the DNOs, engaging other industry parties as needed, are being directed to give proper consideration to each of the issues set out below whilst preparing and progressing modification proposals to implement the terms of the Directions. If, following such consideration and having regard to the SCR Decision Principles, NGESO and / or the DNOs are of the view that alternative modification proposals should be raised to address one or more of these issues then such alternative proposals must be raised. NGESO and the DNOs shall ensure that any alternative proposals raised are consistent with the SCR Decision Principles. The issues are as follows -

1. Distribution of users at high voltages:

⁵⁷ Further information on these systems can be found at the following links:

https://www.mrasco.com/ecoes/, https://www.electralink.co.uk/dts/.

⁵⁸ From discussion with industry stakeholders, we understand it may simplify implementation to align banding definition within LLFCs, and potentially update existing categories to simplify system changes.

⁵⁹ If industry considers the segmentation outcomes from our proposed banding can be achieved, to a close approximation, while better meeting the SCR principles, through an alternative basis for definition, such as point of connection, they should consider and develop proposals on this basis.

We understand transmission-connected sites are likely to have a relatively narrow % range in size compared to other voltage levels, so our direction is for a single transmission band. But we are aware there may be small numbers of substantially smaller sites connected, for example as part of complex sites or private networks. Although agreed capacity data does not exist for these customers, it may be that a derived capacity level could better inform an assessment of the range of these customers. It is possible that this further analysis may suggest more than one charging band should apply at the transmission level.

The ESO should consider the materiality of this potential issue, having regard to the SCR Decision Principles, and develop and bring forward alternative proposals to address any identified concerns, should they consider the range of transmission sites suggests that (as at other voltage levels) some degree of segmentation is warranted. This should include considering i) a similar basis for banding as at EHV, and alternatively ii) an exceptions mechanism to address very small or complex sites at transmission level.

2. Variation in user distribution across DNO regions:

Band thresholds will be set on the basis of all customers across GB at each voltage level. There may be circumstances, notably at EHV, where regional differences in customer types lead to substantially different distributions of customers in a DNO region. This may notably be the case across the Scotland-England boundary. This may on occasion result in very low customer numbers in some bands. We do not consider this is likely to be a problem, but we recognise there may be a concern that applying segmentation at a GB level could give rise to issues under the SCR Decision Principles, such as commercial sensitivity or charging volatility.

The DNOs should assess the materiality of any potential issues, having regard to the SCR Decision Principles, and develop and bring forward proportionate proposals for options to address this, if they consider it to be warranted. This should include applying regionally-derived boundaries on the same basis, rather than GB-wide boundaries for the purposes of distribution residual charges, potentially in that area only, or combining bands when a minimum number of customers would be within a band.

3. Substantial changes in use of a site during a fixed band period:

For a small number of users, significant changes of use, notably upon change of tenancy or ownership, of commercial premises may result in material reductions in the capacity required at the site on which such premises are on during a fixed period prior to the next band review. In exceptional cases, this could result in impacts on business customers which may be considered disproportionate. Equally, significant increases in agreed capacity required may also occur during a fixed period.

The ESO and DNOs should consider the materiality of this issue, having regard to the SCR Decision Principles, and develop and bring forward alternative proposals to address this, if they consider it to be warranted. Any such proposal should include an exceptions process to apply for reclassification of a user to another lower band in tightly restricted circumstances, where substantial changes in usage occur, resulting in significant changes in the level of agreed capacity required. We envisage that firm documentary evidence such as proof of change of ownership or tenancy, or a company Director's letter confirming exceptional and significant changes of use of the site – such as from an energy intensive industry to a low usage commercial enterprise, resulting in a change, the extent of which exceeds some form of materiality threshold or thresholds - would likely be required. The process must also provide for a user to be reallocated to a higher band during a period, should their agreed capacity requirements increase significantly.

4. Alternative proposal for non-half hourly transmission residual

Currently, there is no distinct Transmission Demand Residual calculated for those demand customers charged on a non-half-hourly basis, as distinct from a forwardlooking component of the charge. These reforms will require a transmission residual charge to be applied to all demand customers, including non-half-hourly customers. Our direction is for the applicable residual to be apportioned between half-hour and non-half-hourly demand customers in proportion to their respective contributions to net consumption volumes. This will involve the derivation of a new approach to derive an explicit, separate residual component of the charge.

The ESO should consider, having regard to the SCR Decision Principles, the merits of this approach, and whether an alternative proposal warrants further assessment. The ESO should develop and bring forward alternative proposals to address this, if it considers it to be warranted. Under such an alternative, the TNUoS charge for customers charged on a non-halfhourly basis would remain calculated as per the applicable charging methodology, and would be treated as a residual charge in its entirety, without a distinct forwardlooking component for these customers.

3.60. We consider that the implementation of the above non-domestic banding will reduce harmful distortions, as set out in our assessment below. To ensure that this is the case in practice and given the potential changes in the sector, we consider it prudent for the bands to be reviewed, in line with the RIIO price controls for Electricity Transmission. At the first review of banding ahead of RIIO-ET3, we expect the ESO and distribution network licensees to consider the extent to which consumers have sought to reduce their capacity ahead of the band setting, and how far this reflects their actual usage of capacity, including the case for any potential adjustments to allocation to banding which may be needed to reduce distortions. This may include considering customers' patterns of network usage, such as the extent to which they may have exceeded agreed capacity levels and band boundaries, and allocating customers to bands based on longer duration of data, up to the full period of a band. Relevant network licensees must have regard to this review in relation to their retention of relevant data through the first period, prior to the initial review of charging bands.

3.61. At this first review ahead of RIIO-ET3, we also expect relevant licensees to review and consider any refinements which may be needed to take account of the implementation of any reforms under the Network Access and Forward-looking charging SCR, in particular in relation to the definition of access rights. Should agreed capacity or other capacity data becomes widely available for LV user groups for whom bands are defined on the basis of net consumption volumes, bands will be reset at the next review on that basis.

3.62. Having set out the detail of our decision (which is reflected in the terms of the associated Directions issued to ESO and the DNOs), we explain below our assessment process and reasons for our decision.

Summary of our assessment

3.63. We agree with those stakeholders who suggested that an agreed capacity residual charge is not desirable for small users who do not have an agreed capacity level, given the lack of available data to base these charges on. We think a fixed charge better meets our principles for these users, but agree that domestic customers should not be charged

separately to one another, given their otherwise similar characteristics. Many respondents supported this approach.

3.64. For larger users for whom agreed capacity data is available, an agreed capacity charge would be simple to implement. But we consider it would result in potentially disproportionate increases in charges for the largest consumers, potentially involving annual residual charges up to several £million. We have not identified suitable variants which would sufficiently mitigate these impacts while performing better against our TCR principles. We therefore consider a refined fixed charge better meets our principles for these users.

3.65. Our view continues to be that residual charges should be allocated between users at different voltage levels and in different segments based on net volumes. We think this tangible basis in energy usage provides a strong justification, and note the lack of alternative datasets which exist for all customers. We note that larger users would face a somewhat greater share of residual charges than today but we consider this to be fair and proportionate.

3.66. We continue to believe further segmentation of users is needed to increase the equity of charges - a large range of users of different sizes in a single line loss factor classes would face the same fixed charge under our minded-to proposal, which we do not consider meets our fairness principle.

3.67. Our proposals in our September open letter sought to improve the degree of equity for users under a fixed charge approach. We have decided to implement a refined version of our fixed charging bands. Where users have agreed capacity data, this will form a less avoidable basis for segmentation and should be used, while net consumption volumes are a justifiable basis for those who do not. We agree with those respondents that suggested users connected to the LV network who have agreed capacity should also be segmented on this basis, rather than volumes.

3.68. We recognise a banded fixed charge will be somewhat more complex to implement than our other leading options. We have engaged further with stakeholders on practicalities through the consultation process, to better understand the scale of any changes needed and any aspects of the approach which would benefit from simplification. We have not received evidence to suggest the proposal cannot be implemented, nor that the costs would be sufficient to outweigh the benefits of reform. We have simplified the design of the banding and consider that industry has scope to develop a suitable approach to implementation which builds on existing systems in a proportionate way.

3.69. We outline our assessment in further detail below.

Our final assessment and reasons for our decision – (1) domestic consumers

Our assessment and reasons for our decision

3.70. We proposed two domestic consumer segments with different charges under our preferred fixed charge option in our minded-to consultation, under which domestic consumers with Economy 7 meters would face a higher charge than other households, reflecting their higher average usage as a group. We also consulted on an agreed capacity charge option, with low, medium and high consumption charges, based on deemed capacity levels.

3.71. We did not propose any specific adjustments for vulnerable consumers as we considered explicit changes to charges were not the best approach to address vulnerability. People move in and out of vulnerability over time and also move location, which makes it difficult to link network charges to vulnerability. We indicated that we would consider distributional issues in assessing implementation options, alongside other factors.

3.72. Stakeholders raised concerns that our proposal to charge Economy 7 users separately under a fixed charge approach would be unfair, stating they do not generally drive greater network costs. Respondents also outlined that with the roll-out of smart meters and half hourly settlement⁶⁰, this distinction will become less meaningful as, over time, most meters will be replaced with smart meters. Several respondents emphasised the need to consider the impacts on low using and vulnerable consumers in reaching our decision.

⁶⁰ We expect that market-wide half-hourly settlement will expose energy suppliers to the true cost of supply and put incentives on them to help their customers shift their consumption to times when electricity is cheaper to generate or transport, enabling significant benefits for consumers and the energy system as a whole.

3.73. Some stakeholders raised concerns with the approach of deeming an agreed capacity level for domestic users under an agreed capacity charge. They noted this could risk specific customers under or over-paying their share of charges. Some respondents suggested a fixed charge for small users could be combined with an agreed capacity charge for larger users, for whom agreed capacity data is available.

Our view

3.74. We remain of the view that domestic users should be treated separately from nondomestic users due to their different characteristics.

3.75. We share concerns with the deeming of agreed capacity levels for small users, given the lack of an agreed basis for these customers. We are concerned that there is a lack of a clear and justifiable basis on which to differentiate between domestic consumers to identify the most suitable deemed capacity level. This would likely result in a degree of arbitrariness in their assumed capacity level as the basis for their charge, performing less well against our justifiability principle. The deemed values in our minded-to decision were illustrative values based on individual consumers' usage, rather than diversified demand.⁶¹

3.76. We do not consider an agreed capacity charge for domestic consumers is suitable at this stage, given the absence of robust data to support their capacity level. We also remain of the view that volumetric charges are not an appropriate basis for residual charges for domestic users, given their potential for distortions, our desire to balance equity and equality, particularly given the broad similarities of domestic consumers' usage levels, and the fact that we have not seen a compelling case to differentiate between higher and lower domestic consumers on the basis of vulnerability. We note that tariffs rely on suppliers to pass through charges. While we expect high pass through of benefits to consumers over the timescales in question, specific changes to charging structures may not always be directly reflected in tariffs in the near term.

3.77. We have decided to implement a fixed charge for domestic consumers.

⁶¹ By diversified demand we are referring to the aggregate contribution that small users make to use of the network. Because of diversity in individual users' usage patterns, their aggregate usage at a given point will be lower than the sum of their individual maximum usage.

3.78. The assessment of the two domestic charging options from our September 2019 open letter against the TCR principles is presented in Table 3 below.

Criteria	Reducing harmful distortions	Fairness	Proportionality and practical considerations		
Options		 a) Equity and equality b) Simplicity c) Transparency d) Justifiability, and e) Predictability 	Practical challenges	Proportionality: Short term distributional impact for consumers	
Refined fixed charge (Assuming a single domestic band, as set out below)	Removes key existing distortions as no possibility of changing behaviour to reduce the fixed charge.	Transparent and justifiable basis for charge. Domestic consumers have a high degree of similarity in their usage, and would be treated as such.	Simple to implement	Those who use least electricity see an increase in their residual charge. Those who use the most will see a decrease. The typical domestic user is better off from our residual reforms overall.	
Agreed capacity charge with deemed capacities for domestic	Removes key existing distortions. Though depending on the basis for deeming capacity, some users may seek to change their deemed capacity level.	Allocation of users to deemed capacity levels may be seen as somewhat arbitrary.	Requires deeming for users who do not have agreed capacity data so less practical. May require new dataflows and system	Domestic consumers' charges increase under the methodology, allocating based on deemed capacity.	

Table 3 Assessment of domestic residual charging options from September open letter

3.79. We further considered the most appropriate form of fixed charge for domestic consumers, bearing in mind the impacts for low consuming and vulnerable consumers, in view of concerns respondents raised with our minded-to proposals.

3.80. While, as a group, consumers with Economy 7 meters use more electricity than the average household, both domestic groups cover a broad range of consumption, with substantial overlap between them. A significant proportion of consumers with Economy 7 meters are believed not to have storage heating, and many may have Economy 7 meters for historic reasons. Based on further assessment, we have accepted there are good reasons against having a separate Economy 7 category and do not consider consumers should be charged separately on this basis. We consider there is clear overlap between customers in these groups and the distinction based on metering type may be for historic reasons. We also consider the distinction will become less relevant as the smart meter rollout progresses.

3.81. We assessed several alternative options, considering how they could address the fairness and vulnerability concerns expressed by stakeholders. Each of the options are described below together with a summary of the anticipated impact of each on different categories of domestic consumers. We undertook a principles-based assessment of these refined options for domestic banding, which is presented below.

3.82. We have also undertaken further analysis to try and understand the impacts of our reforms on vulnerable consumers. There is a relative lack of data available to do this - as such we have followed a similar approach to the minded-to consultation. We have drawn on the Energy Demand Research Project (EDRP) and Low Carbon London (LCL) datasets which provide a breakdown of energy use broken down by ACORN⁶² characteristics.

3.83. We have focused our analysis on the 'C5' category, which contains the highest instances of vulnerability.⁶³ Within this C5 category, we estimate that there are around an estimated 500,000 users in the lower quartile of demand, and 380,000 in the upper quartile. This is compared to an estimated 910,000 users in the middle two quartiles. This suggests that, while there is some correlation between vulnerability / affluence and energy usage, there are significant numbers of vulnerable consumers across usage levels.

3.84. While domestic consumers have diverse characteristics, there is a high degree of similarity in some key ways. Their level of consumption is relatively similar compared to other network user groups, with the vast majority falling within around an order of magnitude size range. Our assessments have indicated that vulnerable consumers are present in most domestic consumption groups, and that there are a range of consumption levels in all demographics. As residual charges collect a fixed pot of money, if we were to adopt an option which reduced charges for those who use less electricity, this would result in an increase for those who use the most electricity, a significant number of whom will also be vulnerable.

3.85. In each of the alternative options we assessed we maintained the distinction between domestic and non-domestic users, and apportioned the amount of residual charge

⁶² ACORN categories are a high-level consumer classification that groups UK population segments by their demographic data, social factors, population and consumer behaviour. They are not designed to shown vulnerability so these findings are used cautiously.

⁶³ The C5 category is characterised by high levels of vulnerability and low affluence. We have therefore considered this group as more likely to be vulnerable.

for each voltage level and distribution licensed area by the net volume domestic consumers take from the system.

- **Option 1 Single domestic band:** Sharing the residual charges for the transmission network and the distribution licence areas equally among all domestic consumers, with an illustrative charge of £67. This would **increase charges for low using** vulnerable consumers and **reduce them for high using** vulnerable consumers.
- Option 2 Two domestic bands higher use band: An alternative approach could be to define a second domestic user band, set at the upper quartile of domestic electricity consumption. The highest consuming 25% of customers use c50% of the electricity consumed by all domestic customers. Under this option, those customers would receive a higher fixed charge. The other 75% of domestic customers would receive a lower fixed charge by dividing the remaining c50% of domestic residual charges between them. This option would remove almost all of the increase for vulnerable lower consuming users, but instead increase charges for vulnerable higher consuming users.
- Option 3 Two domestic bands lower use band: A similar approach to the higher use band would be to separate out those consumers who use the least electricity.⁶⁴ Under this option, 8% of domestic residual charges would be recovered from the lowest using 25% of consumers, reflecting their lower share of usage, with the remaining 92% of the domestic residual charge being recovered from the upper 75% of households. This option would result in lower fixed charges for the lowest and highest users of electricity, but higher charges for average users. This would reduce costs for low and high users, this option would see the 'typical', domestic consumer pay more. This would include illustrative charges of £21 for lower users and £83 for medium and higher users.

 $^{^{64}}$ We also investigated implementing a band at the median level. We considered this less desirable. It could lead to a significant (£65) differential in charges for very similar domestic users. We consider setting a boundary here would provide less targeted mitigation for vulnerability concerns, and would divide a larger proportion of households with very similar use than other alternative options.

Criteria	Reducing harmful distortions	Fairness	Proportionality and practical considerations	
Alternative options		 a) Equity and equality b) Simplicity c) Transparency d) Justifiability, and e) Predictability 	Practical challenges	Proportionality: Short term distributional impact for consumers
1) Single domestic band (this is the comparator)	Single fixed rate most likely to reduce harmful distortion as there is no possibility of changing behaviour to reduce the fixed charge.	Domestic consumers have a high degree of similarity in their usage, which the single charge would reflect. No boundaries created.	Simple	Those who use least electricity see an increase in their residual charge. Those who use the most see a decrease. The typical domestic consumer is better off from our residual reforms.
2) Two bands with higher use band	Some potential for incentive to manage the residual charge by altering consumption patterns. Lower band is only in reach for those who are already high users (25% of domestic consumers).	Adds additional equity into the charge – those who use more pay more, but at the loss of equality by differentiating based on usage ⁶⁶ It is less simple, predictable and transparent.	Less simple (re- calculation of the charge periodically). This creates potential legacy and volatility issues.	Softens the distributional effect for the lowest user, but increases charges for higher users. The typical domestic consumer is better off from our residual reforms.
3) Two bands with lower use band	Some degree of incentive is more likely to be introduced to manage the residual charge by altering consumption patterns. 75% of households in upper band could in theory aim to reduce usage to fall within lower band, though we would not consider this would be practicable for all.	Adds additional equity into the charge – those who use more pay more, but at the loss of equality by differentiating based on usage. It is less simple, predictable and transparent. Lower justifiability as treats larger number of similar consumers differently, given the boundary falls among the larger number of similar lower users.	Less simple (re- calculation of the charge periodically). This creates potential legacy and volatility issues.	Softens the distributional effect for the lowest user, but increases charges for all other user groups. The typical domestic consumer is worse off from our residual reforms.

Table 4 principle-based assessment of alternative domestic banding options⁶⁵

3.86. The effects of these options on the most vulnerable consumers are illustrated in Figure 4 below, assuming full pass-through of charges from suppliers to consumers.67

 ⁶⁵ Nb the RAG ratings presented in this table are relative to one another, to illustrate the contrast between this focused set of options and should not be compared directly to other options.
 ⁶⁶ In our minded- to consultation we indicated that we felt a trade-off between equity (charges that

vary with use) and equality (charges that are the same across users) was required in order to best meet our objectives.

⁶⁷ As noted above, we expect the pass-through of benefits from suppliers and generators to
*Figure 4 Illustration of distributional impacts of alternative fixed charging options for domestic consumers*⁶⁸



EDRP Acorn Category (1-5); Positive numbers indicate increases in charges; * Uses 4600kWh for consistency

3.87. Having considered the impact that each of the options would have on domestic and vulnerable users, we have decided to introduce one overall domestic consumer category.

3.88. On balance, we think that a single domestic band, with equal residual charges for all domestic consumers provides a reasonable balance between the different electricity usage of domestic consumers, including vulnerable groups across the usage levels, as well as ensuring that there are no incentives to change behaviour in order to reduce charges. The alternative options we have considered for domestic consumers would not provide targeted support for vulnerable consumers. Additionally, as we have noted in our Consumer Vulnerability Strategy 2025, we consider any actions primarily designed for substantial redistribution of costs in relation to address affordability concerns is a matter for

consumers to be high over the timescales in question, though we recognise that specific changes to charging structures may not always be directly reflected in tariffs.

⁶⁸ This chart shows the differences between the options we have considered for groups of users of increasing vulnerability and reducing affluence across the x axis. The three bars show the change to bills for the lowest, median and highest percentiles of users if the changes are passed directly through to consumers on a 1 for 1 basis. ACORN, the data used is from a demographic dataset produced by CACI, further details explaining this can be found at https://www.caci.co.uk/blog/acorn-explained. However, this should be used cautiously as the data is not specifically designed for vulnerability analysis.

government.⁶⁹ We will consider, as part of our work on potential future price protection, whether any additional price protection is required, particularly for consumers in vulnerable situations. This option is also simple to implement.

3.89. Our related work on improving the forward-looking cost-reflective network charges aims to help ensure that those who use the electricity system less can benefit from lower charges where their actions would help reduce future network costs.

3.90. Domestic consumers overall will benefit by an average of £5 per annum from our reforms. But we recognise that charges for some low-using consumers will be higher than they are today – around £24 for our illustrative low user, while for others they will fall further – around £40 for our high user. As explained above, the evidence we reviewed suggests that there are vulnerable consumers in most domestic user groups, not just those who use the least electricity. We need to consider the needs of all vulnerable consumers.

3.91. Significantly, we continue to believe that the network charging structure is not the right vehicle to address vulnerability concerns because of the inability to target support accurately onto those consumers who most need it, and the inherent trade-offs involved. We are conscious of the potential impact on affordability, particularly for consumers who may use less electricity or are on a lower income, but consider that more targeted approaches, such as retail market or wider policy solutions would be better suited to mitigating any concerns with the effects of changes to the recovery of residual charges. Over time, we expect the majority of domestic consumers to benefit from our reforms overall.

3.92. We have also decided that the single domestic band should include those with Economy 7 meters. Implementing a single domestic band which incorporates Economy 7 users changes the impact of our proposals compared with our minded-to decision. The effect of this decision is that a low using consumer within the Category 5 (C5) ACORN classification will see an increase in the residual charge (currently paid by suppliers) of £25, whereas a higher consuming user within the same category will see a charge reduction of £39. A median consuming user within C5 will increase by £5 under the single domestic

⁶⁹ <u>https://www.ofgem.gov.uk/system/files/docs/2019/10/consumer_vulnerability_strategy_2025_.pdf</u>

band proposal, noting the median C5 user has lower consumption than the median, typical consumer.

Our final assessment and reasons for our decision – (2) non-domestic consumers

3.93. We have reviewed and considered further refinements to the non-domestic residual charging options set out in our 3 September 2019 open letter, considering respondents' comments and suggestions in undertaking our own further work, as described below. Notably, respondents raised concerns about the degree of equity under our proposed fixed charge approach, given the wide range of non-domestic users. Some suggested a hybrid of an agreed capacity charge for larger users and a fixed charge for smaller users without an agreed capacity, in view of concerns raised with the deemed capacity approach.

3.94. Our assessment of deemed capacity for small non-domestic users aligns with that for domestic users. We therefore did not think this option should be taken forward, given these concerns, and noted in our September open letter consultation that we had considered a hybrid option similar to that outlined above.

3.95. We have sought to identify how the two broad approaches we set out in our open letter of 3 September - of a banded fixed charge and a hybrid of agreed capacity charges for larger users and fixed charges for smaller users - could each be improved to address issues identified through the consultation process, with the aim of identifying a refined approach which could better meet our TCR principles. We also considered a further blended fixed-linear charge, informed by suggestions identified through consultation, whereby all non-domestic users would each have a fixed and a linear element of their charge – either agreed capacity where this data exists, or net volumes for consumers where this data is not available.

3.96. The three options we have taken forward for final assessment for non-domestic users are summarised as follows, and further set out below:

- **Option 1 Final banded fixed charge:** A variant of the banded fixed charge we consulted on in the September open letter, with simplified banding.
- **Option 2 Final hybrid fixed-agreed capacity charge:** An agreed capacity charge for larger users with an agreed supply capacity, and a fixed charge for smaller users, with banding on the same basis as Option 1.

• **Option 3 - Blended fixed-linear charge:** A charge combining a fixed and linear component of the charge for all users, with agreed capacity as the linear component for larger users with an agreed supply capacity, and net volume for smaller users.

Final assessment – summary of final leading options				
Option	Residual charge	Segmentation approach	Charge calculation	
	allocation			
1. Final	Applicable residual	Users connected at each	Residual charges for each	
banded	charges for each	voltage level are	customer band are divided equally	
fixed	licensed area are	segmented further into	among all users in that band - all	
charge –	allocated to the	bands based on the	users in a band pay the same fixed	
our	different voltage	distribution of consumers	charge.	
decision	levels, according to	in the population at each		
	the total net	voltage level. The residual		
	consumption	charges for each voltage		
	volumes of all	level are allocated to		
	consumers at each	customer bands based on		
	voltage level.	total net consumption		
		volumes for all consumers		
		in each band.		
2. Final	Applicable residual	For large users - n/a - a	Residual charges for users with	
hybrid	charges for each	linear capacity charge is	agreed capacity charges are	
fixed-	licensed area are	calculated, so no further	divided equally among units of	
agreed	allocated to the	allocation to bands	capacity at that voltage level - all	
capacity	different voltage	required.	users pay the same per unit	
charge	levels, according to		capacity charge in each voltage	
	the total net	Small users are further	levels.	
	consumption	segmented into bands		
	volumes of all	based on the distribution	Residual charges for each	
	consumers at each	of consumers in the	customer band are divided equally	
	voltage level.	population as per the fixed	among all users in that band - all	
		charge design above.	users in a band pay the same fixed	
			charge.	

Figure 5: Summary of final options for non-domestic customers

Option	Residual charge allocation	Segmentation approach	Charge calculation	
3. Blended	Applicable residual	Bands for the purposes of	Allocated residual charges are	
fixed-	charges for each	both fixed and linear	divided between fixed and linear	
linear	licensed area are	charge components are	charges for each customer	
charge	allocated to the	defined at the voltage	segment in the relevant proportion	
	different voltage	level, with	(eg 75%/25%).	
	levels, according to	costs for users connected	Residual charges allocated to the	
	the total net	to the LV network further	linear (agreed capacity or	
	consumption	apportioned between half-	volumetric) charge component are	
	volumes of all	hourly consumers, who	divided equally among units of	
	consumers at each	currently have an agreed	capacity / volume as applicable in	
	voltage level.	capacity charge, and non-	that band. All users in a band pay	
		half-hourly consumers	the same linear charge.	
		who do not, based on total	Residual charges allocated to the	
		net consumption volumes	fixed component are divided	
		for all consumers in each	equally among all users in a band -	
		group.	all users in a band pay the same	
			fixed charge.	

Final accessment - summary of final leading options

3.97. While a number of stakeholders recognised the value of a fixed charge in theory, and the increased equity our proposals were aiming for, the majority had concerns with our proposed fixed banding as set out in our September open letter and many did not support this option. Concerns raised centred on the practicality of these proposals and the potential for them to introduce new harmful distortions.

3.98. We therefore undertook further analysis on our banded fixed charge proposal including in relation to the scale of implementation challenges that were highlighted by some stakeholders, and the extent to which any such concerns could be mitigated through refinements to the design or implementation approach. We benchmarked this option against a variant of the agreed capacity hybrid charge we consulted on. We considered a range of options but did not identify further refinements which we considered would improve the agreed capacity charge applied within the hybrid set out in the open letter against our principles.

3.99. Below, we outline our assessment of these final leading options against the TCR principles. This assessment is summarised in Table 5 Assessment against our principles for leading options for non-domestic customers below.

Criteria	Reducing harmful distortions	Fairness	Proportionality and practical	considerations
Options		 a) Equity and equality b) Simplicity c) Transparency d) Justifiability, and e) Predictability 	Practical challenges	Proportionality: Short term distributional impact for consumers
1. Final banded fixed charge – our decision	Removes key existing distortions. Somewhat increased potential to avoid near boundaries, agreed capacity requires sustained reduction.	Introducing more segments, based on usage improves equity. Bands may be seen as arbitrary and users either side face different charges.	More changes required in implementation, particularly for small users. These may be seen as disproportionate.	Reduces extremes of distributional effects but creates boundaries.
2. Final hybrid fixed-agreed capacity charge (combining an agreed capacity charge for large users and a fixed charge for small users)	Removes key existing distortions. Some potential to avoid, though sustained reduction needed for agreed capacity. Access reform may strengthen this.	Linear charge increases equity, though little equality remains for large users. Small users as per fixed charge above. Different degrees of equity and equality for large vs small users.	Relatively easy to implement for large users, though involves calculating two charges. May require some new data processing. Small users implementation as per fixed charge above.	Increases equity but significant distributional impacts for larger users which perform less well in our proportionality assessment. Small users as per fixed charge above.
3. Blended fixed- linear charge (combining a linear and fixed component of the charge)	Removes key existing distortions. Some potential to avoid, though agreed capacity is only a component of the charge. Volume element for small users strengthens distortion, but small users less likely to respond, may reward energy efficiency / solar.	Linear charge increases equity. Fixed charge component contributes to equality, but redistributes between large and small users rather than groups with more similar usage.	Relatively easy to implement though involves calculating two charges. May require some new data processing.	May limit most extreme distributional effects, but significant distributional impacts likely to remain. Fixed element reallocates charges between large and small - significant increases for large users only mitigated by significant increases for small.

Table 5 Assessment against our principles for leading options for non-domestic customers

Assessment of harmful distortions for non-domestic charges

1. Final banded fixed charge

3.100. Some stakeholders told us that the charging bands we proposed in our September 2019 consultation would lead to an increase in harmful distortions when compared to those we consulted on in November last year. They indicated that the use of bands linked to agreed capacity or volumes would lead to a strong incentive for those users who were close to the charging boundary to take action to reduce their residual charge. They suggested that the step changes in charges at the boundaries of bands would emphasise the potential for savings and may lead to a greater response from some users. We have undertaken analysis to consider both the apparent static incentives which users might face, and ongoing factors which effect the ability to realise savings over time.

Static incentives

3.101. We have undertaken a range of analysis which assesses the static incentives of the refined fixed charge. We have also compared this to an agreed capacity hybrid charge and a blended fixed-linear charge which stakeholders indicated might be simpler options to achieve desired outcomes.

3.102. We have carefully considered whether the differences in charges at either side of the boundary are sufficient to drive a response, focusing on the case for investment in on-site technology. We considered scenarios based on estimated technology costs for different scales of investment, if a user wanted to reduce their capacity, to inform an estimate of the extent to which users across a band would see a static incentive sufficient to support an investment aiming to reduce their residual contribution.

3.103. Our analysis suggests the differences in charges across boundaries are of a level which would constitute a financially viable standalone incentive to drive some users to aim to respond, on a static basis (\sim 2-9%⁷⁰ of the band in our central case). We have undertaken a range of sensitivities to this central case, where the this incentive is higher.⁷¹ Users further from the boundary would also need to reduce their capacity by larger amounts to attain any savings, which may present an additional barrier.

Attainment of savings over time

3.104. The design of the bands we have proposed would significantly limit the potential for network users to realise the potential static savings identified above, thus minimising the distortions. Key factors which act to reduce the level of attainable incentives include:

⁷⁰ This range was updated on 18 December 2019 with amended data from our consultants.
⁷¹ Under a high sensitivity scenario, our estimates suggest up to 40% of the band may face a static incentive. This would be expected to be considerably lower in lower residual areas.

- Banding based on user populations at each voltage level: the design of the bands would result in 40% of consumers being placed in the lowest charging bands at each voltage level. These users could only reduce their charge by changing their voltage level of connection, which is a substantial hurdle and in general unlikely to be practical. As a result, any financial incentive to invest in equipment to reduce exposure to residual charges is expected to be limited to larger users within a voltage level, a subset of the 60% of users in the higher bands at each voltage.
- Review of banding: we have proposed a process for periodic review of the banding, the result of which could be the reallocation of users to a different charging band. This means that anticipated savings arising as a result of being placed into a lower charging band are uncertain over the longer term. As the banding is based on customer percentiles, the actions of other users could also affect an individual user's ability to move bands. Users could typically therefore only assume savings from any investment over a relatively short period ie up to the next charging band review. Any payback on investment is also delayed, with non-domestic consumers allocated to bands based on average usage over at least a two year period, further reducing incentives to invest.
- Allocation of charges: at the point at which charges are calculated and bands are reviewed, the allocation of residual charges to consumer groups in a given band is based on their contribution to net consumption volumes. This means any consumers who had sought to reduce their capacity by reducing demand at peak times, which would not be expected to substantially affect their consumption volume, would still contribute the same amount of volume to the s overall share of the residual charge allocated to that band.

Behavioural factors

3.105. We have drawn on our earlier study of large users and their likely response, as well as points put to us through consultation responses, to understand the likely drivers and conditions for any response.

3.106. Respondents have suggested that the presence of a boundary, notably where the step change in charges is significant, will increase users' focus on seeking opportunities to reduce their capacity below the boundary. There is some suggestion in tax literature that boundaries lead to clustering of users in the vicinity of boundaries, which may provide support to the view that users aim to respond to boundaries.

3.107. We also recognise there are a number of factors which may limit consumers' ability or readiness to respond by reducing their capacity, as identified in our earlier work with large users, published alongside our minded-to decision – notably their business reliability needs and opportunity costs.⁷²

3.108. We note accepted economic theory reflects the fact that delayed payback reduces attractiveness of incentives. But we also expect that the level of certainty is likely to be a significant factor in any decision.

3.109. The concern was also raised that the reforms to residual charges could restrict the development of nascent flexibility markets, which are expected to help facilitate decarbonisation. Under the Access and forward-looking charges SCR we are considering reforms to the forward-looking signals, which provide signals for where beneficial flexibility can help reduce future costs on the networks. The TCR reforms aim to remove distortions, to enable the correct signals to be sent for flexibility. Our modelling suggests an increase in grid connected storage under our reforms overall.

2. Hybrid fixed-agreed capacity charge

3.110. Under the hybrid option we considered in the 03 September 2019 open letter, all users could in theory reduce their exposure to residual charges by lowering their capacity, without a limit on payback period for any investments made to reduce their exposure, although the incentive to do so is expected to be low - the reduction in charge for each unit of capacity is less significant than across a fixed charge boundary. In conjunction with other revenue streams, however, higher response to the signal could be feasible. We also have concerns that a per-unit capacity charge, could lead to interactions with reforms currently underway through our Access and forward looking charges reforms, which could potentially result in a stronger emphasis on capacity as a cost-reflective charging signal, in contrast to the aim of residual charge design. While some of the design features of a fixed band could be applied on a linear basis, this would further increase the complexity of the charge.

3.111. Overall, both this option and the fixed charge option were assessed as performing to a similar level against the principle of reducing harmful distortions, removing the key

⁷² A report summarising our research with large users, published as annex 6 alongside our minded-to consultation, is available here: <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 6 - large users.pdf</u>

existing distortions. It was hard to say with any certainty which of the two options would have the greater realisable incentive in practice for users to reduce their exposure to residual charges through reducing agreed capacity and therefore whether one performs significantly better than the other.

3. Blended fixed-linear charge

3.112. Under this approach, we expect realisable incentives would be marginally lower than under either option 1 or 2 above for larger users with agreed capacity. This is due in part to the lower proportion of capacity charge for users to respond to. Additionally, there is a lack of need for further banding under the fixed charge, given the equity provided by the linear element of the charge for all users, removing the potential to avoid the charge by changing usage with the aim of moving between bands. However, for smaller users, this would retain a volumetric charging element, which could increase the potential for distortions for those users.

Summary

3.113. On balance, we have assessed each of the options to be broadly equivalent in terms of their impact on reducing harmful distortions, with option 3, the hybrid fixed / linear charge performing marginally better, particularly for larger users. Our analysis indicates that incentives to change behaviour resulting from the charging structure alone are relatively low for all three options.

Assessment of fairness for non-domestic charges

3.114. In our minded-to consultation, many respondents supported the approach of combining equality between broadly similar users within a band, with equity across bands. A number of respondents felt there was insufficient equity in our proposed fixed charge with bands based on LLFCs, meaning very different users across a band would face the same charge. We agreed with this view and in our September open letter, we proposed a refined approach to increase the granularity of banding, to address these concerns.

3.115. Many respondents to our September open letter recognised our intention to increase the degree of equity with a number explicitly supporting this aim. But many disagreed with aspects of the detail of our approach and a number emphasised they preferred a hybrid option, combining an agreed capacity charge for larger users with a fixed

charge for smaller users. There was also a proposal for a blended linear-fixed hybrid charge as an alternative, simpler way to introduce equity.

3.116. We have identified five components of fairness which we considered in our assessment - equity and equality, simplicity, transparency, justifiability, and predictability.

1. Final banded fixed charge

3.117. We said in our minded-to consultation that we think all final demand users who benefit from the electricity network should pay towards its upkeep in a fair manner. We said equality and equity were both important concepts, but we recognised there was likely to be some tension, as a charge cannot be both completely equal and equitable unless all users are very similar to one another. We said there were arguments for both qualities, and discussions with our consumer panel showed support for both equality and equity in charging arrangements.⁷³

3.118. In our minded-to assessment of a fixed charge, we considered the use of different charges for smaller and larger user groups provided equitable charges across segments, although a single charge within segments might be considered to be less equitable where there was significant range of users within a segment. The reduction in equity may be perceived by some consumers as less fair than other options, but the improvement in equality (resulting from users with similar call on the system paying the same) improves fairness. We also noted the volume linkage to use of the system improves the justifiability of charges.

3.119. Responses to our minded-to consulted broadly supported an approach of equality within bands and equity across. But a number of respondents raised significant concerns that our minded-to proposals did not achieve the right balance between equity and equality – in essence, that the range of users within a segment was too broad and hence equity was too low.

3.120. The updated fixed charge approach we have decided to introduce, based on that proposed in our September consultation and subsequently simplified, retains a balance of

⁷³ The report can be accessed here: <u>https://www.ofgem.gov.uk/publications-and-updates/ofgem-consumer-first-panel-understanding-consumers-views-residual-network-charges</u>

equality within bands and equity across them. However, both the proposal in our open letter and our updated final banded fixed charge increase the overall level of equity compared to the earlier fixed charge based on LLFCs which we consulted on in our mindedto decision, in line with stakeholders' feedback.

3.121. Equality is introduced among relatively similar users compared to under our original proposals, who are adjacent in size, grouped on the basis of their usage of the network (using the proxy of agreed capacity where this data exists, or net volumes otherwise). We continue to think this is a tangible, justifiable basis for establishing charging bands, improving equality among relatively similar users.

3.122. Additionally, consumers in each band contribute to residual charges in proportion to their collective share of net consumption volumes. This increases the tangible, justifiable basis for their charges. Our approach to banding, means a user's charge is derived based on a combination of equity and equality, introducing equality among similar users in a band, with equity across bands – an approach which respondents to our minded-to consultation broadly supported.

3.123. While we have made some simplifications following our September open letter, we note the fixed charge option performs less well against the elements of simplicity than other lead options.

2. Hybrid fixed-agreed capacity charge

3.124. An agreed capacity charge has a high degree of equity, as it scales linearly with users' agreed capacity. However, it has very little equality, which is only introduced through the allocation of residual charges to voltage levels. While we noted in our minded-to consultation that we did not think all users should pay the same, putting greater weight on equity, we also recognised there are arguments for both equity and equality, and proposed a balance between equity across consumer segments and equality within. Our engagement with the Ofgem consumer panel showed support for both equily and equity in charging arrangements.

3.125. The low equality / high equity under this option is most noticeable in its effect for larger users at the extremes of usage levels, as users' whole charge increases linearly with each increment of agreed capacity.

3.126. The lack of available data to set an agreed capacity charge for smaller users also means this option combines a fixed charge for small users and an agreed capacity charge for larger users. This would introduce substantially different degrees of equity and equality for these two user groups. While we note this may be justifiable on the basis of proportionality and practical considerations, it would mean a different balance of these two factors with different outcomes in relation to fairness.

3. Blended fixed-linear charge

3.127. This option combines an element of a fixed charge with an element of a linear charge, either based on agreed capacity or net consumption volumes, based on the data available for the consumers in question. This introduces a combination of equity and equality, which we consider is important.

3.128. However, while a fixed charge element for users across the band introduces equality, it has a less tangible, justifiable basis as all users across a band pay the same fixed charge, regardless of size. There is an element of equity introduced by the linear charge, but this only constitutes a small proportion of the charge, and the fixed charge has no differentiation based on usage. As the equality brought by a single fixed charge is applied across larger and smaller customers, who are less similar, this would be likely to result in smaller users paying a fixed charge that is similar to that of larger users, and hence proportionally much greater relative to their usage, which would reduce (potentially to a significant extent) the fairness of the charge.

3.129. We therefore consider this option has lower equality, with lower justifiability than other approaches, and performs less well under our fairness criteria. It also has implications for proportionality of changes, discussed below.

Summary

3.130. Overall, we therefore consider the refined fixed banding performs best in relation to fairness, as it reflects similarities in consumers' network usage, based on capacity or consumption volumes. It also introduces a balance of equity across each band in a voltage level and equality among similar users within a band – an approach which respondents to our minded-to consultation broadly supported. The other final options do not perform as well in terms of fairness, in view of their lack of equality for similar users.

Assessment of proportionality and practical considerations for non-domestic charges

3.131. Stakeholders told us that the proposals we consulted on in September were complex and may be difficult to implement. Specifically, some respondents said the criteria used for setting the bands were too complex, given the objectives of the policy. Some also indicated that the banding as proposed would require some suppliers to make significant system changes, which again they considered may not be the simplest way to achieve the policy intent. Some large users also argued that the level of charges proposed under the fixed banding would result in disproportionate increases to their charges, and may have implications for competitiveness in their sector.

3.132. A number of respondents proposed a hybrid charge comprising an agreed capacity charge for larger users and a fixed charge for smaller users. An alternative suggestion was a 'blended' fixed - linear charge with an element of each for all users, which was proposed as a simpler alternative to introduce equity.

3.133. Following responses to our minded-to consultation, we commissioned our consultants to assess and remove likely generation sites from the underlying datasets used to model these illustrative charges.⁷⁴ This resulted in the removal of around 50% of sites at EHV, resulting in an increase of around two times in the scale of residual charge for each EHV user. In our direction, we require network licensees to develop a suitable approach to identifying or robustly estimating final demand sites for the purposes of residual charging.

3.134. Below we present indicative charges for users in our indicative DNO region under our final banded fixed charge, the hybrid fixed-agreed capacity and the blended fixed-linear charge. A supporting dataset and accompanying report from our consultants are published alongside this decision.⁷⁵ We used our original user groups as set out in the minded-to decision, with the addition of two illustrative larger users at HV and EHV.

⁷⁴ The methodology followed is presented in the accompanying report from our consultants, published alongside this document.

⁷⁵ We note that our thinking on the hybrid option has evolved in the period since the minded-to decision. Frontier's analysis presents a variant of the hybrid which uses the original LLFCs as the basis for fixed charge segmentation, rather than bands. As noted in their report, the banded fixed charges can be combined instead with the agreed capacity charge for larger users. This is what we present here.

Table 6 below presents an overview of illustrative combined distribution and transmission residual charges under our final options for our illustrative user groups.⁷⁶

Voltage of connection	Illustrative user	User size (small users MWh volumes / large users kVA capacity)	1. Final banded fixed charge	2. Hybrid fixed-agreed capacity charge	3. Blended fixed (75%) - linear (25%) charge
LV non-half-	SME - Low	10	£185	£235	£289
LV half-hourly	SME - High with onsite generation/storage (1)	55	£185	£235	£4,219
	SME - High without onsite generation/storage (1)	55	£430	£235	£4,219
	SME - High with onsite generation/storage (2)	55	£185	£1,096	£4,219
	SME - High without onsite generation/storage (2)	55	£430	£1,096	£4,219
High Voltage	SME - Light industrial HV-connected	2,000	£165,855	£99,382	£72,394
Extra High Voltage	Industrial - EHV- connected without onsite generation/demand management	10,000	£144,436	£265,858	£428,179
	Industrial - EHV- connected with peak generation/demand management	10,000	£144,436	£265,858	£428,179
Transmission	Industrial - T- connected with peak generation/demand management	20,000	£549,123	£447,161	£523,642
	Industrial - T- connected without onsite generation/demand management	20,000	£549,123	£447,161	£523,642
High Voltage	NEW - Large HV	20,000	£165,855	£993,800	£295,999
Extra High Voltage	NFW - Large FHV	100,000	£1,065,388	£2,642,000	£1,022,629
Transmission	NEW - Large T	500,000	£549,123	£11,180,000	£3,206,842

 $^{^{76}}$ This table was updated on 18 December 2019 with amended data from our consultants. This affects the charges for LV HH, HV and EHV consumers only.

1. Final banded fixed charge

Complexity of banding criteria

3.135. Stakeholders said that the four step criteria used for setting and updating the bands was opaque and appeared unduly complex. Some highlighted concerns that it would be difficult to update banding at the review period.

3.136. We were also told that the relevant data is not currently held for the 5 year period over which we proposed the banding be set in our September open letter.

Implementation challenges

3.137. Stakeholders raised concerns that the banding we proposed may be difficult to implement from both a network and a supplier perspective. For the smaller non-domestic user solution, network companies and code administrators indicated two key concerns: i) although data was available to place users into bands, a process would need to be undertaken to assign each network user into their correct band, and ii) banding not linked to LLFCs would result in a significant increase in the number of charges they need to set and changes to systems.

3.138. Consultation responses generally considered the fixed charges proposed for smaller non-domestic consumers to be harder to implement than our proposals for larger non-domestic users.

3.139. Suppliers told us that they had concerns the banding as set out would require a new system flag to be introduced, which could have implication for implementation, and may require significant system changes. Concerns were also raised regarding the dispute process and the process for assigning new customers to bands.

3.140. Given the practical concerns raised, we have considered a range of approaches to implementing a simplified version of the banding which we published for consultation in September.

Refinements to simplify

3.141. We recognise the use, where possible, of existing industry systems and classifications are likely to simplify the implementation of any changes. We have considered

refinements to our proposed fixed charging banding to better enable the use of existing systems and processes.

3.142. We have simplified the basis for banding thresholds. We propose a separate set of bands for customers at each voltage level, and at LV, separately for those with an agreed capacity as the basis for their charging and those without. We have also simplified the criteria we set out and defined a simpler set of bands, based on the distribution of individual consumers in each group, with a small number of conditions to be considered in updating the bands on review, removing the need for a more complex set of criteria.

3.143. We propose a check on the level of change to charges across the boundary. We also intend the industry to consider additional or alternative provisions which may be needed to address any concerns which may exist about small numbers of customers in DUoS bands at higher voltages.

3.144. We recognise concerns from suppliers in particular about the extent of changes which may be needed to dataflows and systems. Taking account of these concerns, we consider industry should explore the benefits of defining these bands as updates to existing classifications, such as LLFCs if industry considers this the most efficient and streamlined solution. We also now propose that bands be set based on a minimum of 2 years' historic data, aligning with the period for which data is typically held, unless a longer period can be achieved proportionately.

3.145. We consider there is a strong role for industry in determining the best approach to system and process changes to implement the reform to residual charging and encourage them to consider how they can build on existing systems and processes to deliver the reforms in the simplest way, requiring the least change. We expect there could be merit in a centralised approach to setting band thresholds and allocating users to bands, which could involve changes under the BSC or other centralised systems, with historic consumption data for smaller users submitted in the necessary format and potential roles for Elexon, Electralink, suppliers and / or their agents in this process. We think this has strong potential to offer a more efficient solution than a fragmented approach across individual parties and we encourage the industry to thoroughly explore the costs and benefits of such an approach.

3.146. While we recognise that this option would result in increases in charges for some users, overall we consider the changes to be fair and proportionate. The degree of change seen by sites at higher voltages is dependent on their current charge. There is significant variation in charges due to location and whether the user manages their exposure to triad charges. Large increases will occur for those who use triad to reduce their exposure to residual charges currently. We think this is fair outcome, since this action reduces users' individual contribution to residual charges but does not bring reductions in system costs. Users paying the same charges reflects the fact that the costs of the existing infrastructure do not change. This is a significant difference from today and one that is more consistent with the TCR's objectives of improving fairness and reduced distortions (in this case competition between customer sites).

3.147. We present a full set of illustrative fixed charges for our sample North-East region below.

Table 7 schedule of illustrative charges for the North-East region under our final banded fixed charges^{77, 78}

Voltage of	User size range	Distribution	Transmission residual	Combined distribution +
connection	- band	residual charge	charge	residual charge
Domestic	Single Segment	£33	£34	£67
	1st Band	£19	£18	£38
LV non-half-	2nd Band	£96	£89	£185
hourly	3rd Band	£222	£207	£430
	4th Band	£631	£589	£1,220
	1st Band	£ 905	£1,088	£1,993
LV half-hourly	2nd Band	£2,097	£1,953	£4,050
	3rd Band	£3,142	£3,125	£6,268
	4th Band	£ 8,222	£7,215	£15,436
	1st Band	£5,034	£4,456	£9,489
нν	2nd Band	£16,508	£16,164	£32,672
	3rd Band	£29,222	£29,492	£58,715
	4th Band	£80,765	£85,091	£165,855
	1st Band	£3,572	£12,292	£15,864
	2nd Band	£17,106	£127,331	£144,436
	3rd Band	£35,838	£342,165	£378,003
EHV	4th Band	£170,934	£894,404	£1,065,338
Transmission	Single Segment	0	£549,123	£549,123

2. Hybrid fixed-agreed capacity charge

3.148. We recognise this option would be simpler to implement for larger users than our final banded fixed charge. Though it may still need some refinement to data processing or existing dataflows, these would likely be relatively minor.

 ⁷⁷ Some totals as presented here may not correspond with the sum of the separate figures due to calculation of underlying components to more decimal places. For further information, see the published Frontier/LCP summary of bill impact data, published alongside this report.
 ⁷⁸ This table was updated on 18 December 2019 with amended data from our consultants. This affects the charges for LV HH, HV and EHV consumers only.

3.149. However, if this were combined with a fixed charge for smaller users, we consider a similar approach to our refined fixed charge, with associated implementation requirements, would need to be adopted to address fairness concerns with our original leading fixed charge proposal in our minded-to consultation.

3.150. In terms of proportionality, our assessment also indicates that an agreed capacity charge could lead to a significant apportionment of residual charges to those users who hold the highest levels of capacity, with the residual charge for some customers rising from relatively low levels today to several £million/year in this option, with high levels of equity but little equality, as noted above. We are concerned that these significant changes in charges are higher than necessary to deliver the policy, noting it also performs less well against our fairness principle, and we do not consider this option performs well against our proportionality principle.

3. Blended fixed-linear charge

3.151. We recognise this approach would be somewhat simpler to implement than our proposed fixed charge. However, we are concerned by its relatively limited ability to introduce equality among similar users. Under this option, it would be hard to mitigate the significant increases which an agreed capacity hybrid leads to for larger users without instead introducing significant increases for smaller users. We are therefore concerned it does not perform strongly against our proportionality principle. For instance, a 75% linear component of the charge could increase smaller users' charges by more than 400%, while a smaller (25%) linear component may leave larger users paying multiples of £1million in network charges.

Summary

3.152. While we recognise the additional equity introduced under a fixed band will increase charges for larger users in the band, we think the banded fixed charge strikes the best balance between equity and equality, taking account of distributional effects and proportionality. The other final options assessed would result in more extreme distributional effects and perform less well against our proportionality assessment.

3.153. The fixed charge has greater practical implications for data and system changes to implement than the other final options assessed, so it performs less well on practicality. However, we still expect the costs to be outweighed by benefits of reform.

Summary of our conclusions for non-domestic charging

3.154. For the reasons set out above and summarised below, we have decided to implement a refined version of the fixed charge option that we published for consultation in September.

3.155. We think fairness and proportionality concerns with an agreed capacity hybrid charge, particularly in relation to the distributional impacts of the charge, mean this is not a preferred option. We have not identified practical variants which could mitigate this in a way which performs better against our principles overall.

3.156. We are concerned that a fixed / linear hybrid charge does not introduce equality within segments of similar users, as we consider it allocated costs between smaller and larger users via the same level of fixed charge. We think this is less fair and justifiable. We are also concerned that it does not enable potentially significant increases in charges for larger users to be mitigated without a potentially significant increase in smaller users charges. It therefore does not perform well against our proportionality principle. We therefore also do not consider this is a preferred option.

3.157. Our final banded fixed charge removes the key existing distortions, while appropriately balancing equity across bands with equality among relatively similar users within them. We recognise charges will increase for some users, but we consider this is fair and proportionate. We recognise the need to balance practicality, with the other TCR principles of fairness and reducing harmful distortions and so have proposed a simplified set of bandings. But we note there may be refinements which can help reduce distortions further, or reduce the practical requirements of implementation and we encourage industry to consider lowest change approaches to implementation. We have highlighted key aspects for industry to consider and develop proposals during the industry modification process or at the review of bands ahead of the next transmission price control.

4. Decision on `non-locational' Embedded Benefits

Chapter Summary

This chapter outlines our final decision on the reforms we proposed to some of the remaining `non-locational' Embedded Benefits in our minded-to consultation. It presents the further work and assessment we have undertaken since the minded-to consultation and a summary of our consideration of the responses received to our consultations.

The scale of the 'non-locational' Embedded Benefits has increased significantly in recent years and we remain of the view that there is no clear relationship between these benefits, which are ultimately funded by consumers, and the costs of operating the electricity system. We therefore consider reform is necessary. Following the findings of the Balancing Services Charges Taskforce, which we have taken into account, we have decided to implement the 'partial reform' option we consulted on, and launch a second taskforce to consider the application of the TCR principles to balancing services charges.⁷⁹

Although this chapter can be read as a standalone chapter, we recommend that you also read the Quantitative Analysis of our reforms, chapter 5 and the associated Impact Assessment as there is substantial cross-referencing between them.

Introduction

4.1. "Embedded Benefits" is the name given to the differences in transmission and balancing services charging arrangements between Smaller Distributed Generators (which are less than 100MW connected to the distribution network) and larger generators (>100MW) connected to either distribution or transmission networks. Some of these benefits extend to micro-generation and on-site generation, particularly when power is

⁷⁹ Two options were proposed in the minded-to consultation, 'partial' reform which includes setting the Transmission Generation Residual to zero and removing the ability of Smaller Distributed Generators to offset Suppliers' net demand which reduces their liability for balancing services charges. The alternative proposed was 'full' reform, which included the two elements of 'partial' reform but would also have included making Smaller Distributed Generators liable for balancing services charges in the same way that larger generators are.

exported onto the network. ⁸⁰ Prior to 2017, all Embedded Benefits provided beneficial treatment to Smaller Distributed Generators. However, since the 2017/2018 charging year, one of the charges not faced by Smaller Distributed Generators (the Transmission Generation Residual charge) has become negative so that larger generators now receive a tariff reduction, for which they are credited, rather than paying an additional charge. This means there is now a mix of benefits and disbenefits to Smaller Distributed Generators.

4.2. The amount of distributed generation has been rapidly increasing. Figure 6, below, shows the growth of distributed generation, with notable increases in solar and Combined Cycle Gas Turbine (CCGT), Open Cycle Gas Turbine (OCGT), and reciprocating gas/diesel generation.

⁸⁰ Microgeneration is defined as solar photovoltaic or wind installation with a Declared Net Capacity of 50kW or less.



Figure 6 Increases in metered distributed generation⁸¹

4.3. There are a number of Embedded Benefits. The non-locational Embedded Benefits, which are being reformed through TCR are described in Table 8 below. Embedded Benefits can now provide benefits to all forms of generation, including Smaller Distributed Generation, on-site generation and larger generation.

4.4. On-site generation does not pay network charges in general, but can receive similar treatment to Smaller Distributed Generation when it exports power onto the network. For this reason, we have also considered the benefits that on-site generation can receive in respect of transmission and balancing services charges compared to metered generation, and how our decision will affect them. Our decision will address some of these differences, as discussed below. Further reforms to balancing services charges (which we expect to be

⁸¹ Source: National Grid Future Energy Scenarios 2018, CHP stands for Combined Heat and Power.

implemented following a second Balancing Services Charges Taskforce) should address the key remaining non-locational Embedded Benefit we identified for reform in this SCR, as set out in Table 8 below.⁸² In addition, the Access and forward looking charges review is considering reforms to the 'locational' Embedded Benefits.

⁸² There are other, smaller Embedded Benefits which are lower in value. We have not considered Residual Cash Flow Reallocation Cash flow (RCRC) and Assistance for Areas with High Electricity Distribution Charges (AAHEDC which was introduced by the Energy Act 2004 and is levied on electricity supply by licensed suppliers, implemented via licence conditions) in any detail since they are low in value and hence unlikely to be causing major distortions. Nor are we considering reforms to the treatment of transmission losses. Further information can be found in Chapter 5 of the mindedto consultation,

https://www.ofgem.gov.uk/system/files/docs/2018/11/targeted charging review minded to decisio n and draft impact assessment.pdf, or Annex 5 of the minded-to consultation, https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 5 - reform to nonlocational embedded benefits.pdf.

Embedded Benefit	Treatment of different types of generation and on-site generation
Transmission Demand Residual	By reducing a supplier's net demand, Smaller Distributed Generation and exporting on-site generation can receive payments from suppliers and NGESO for helping suppliers to reduce their Transmission Demand Residual payments. This benefit was addressed by CMP 264/265. Non-exporting on-site generation can receive the same benefit. This benefit is being addressed by the new residual charges under TCR.
Transmission Generation Residual (Embedded Benefit 1)	Smaller Distributed Generation does not pay or receive the Transmission Generation Residual. Neither does on-site generation. Since the residual is currently a negative charge, this is a benefit for larger generators and a disbenefit to Smaller Distributed Generation and on-site generation. This is being addressed by setting the TGR to zero under this TCR decision, (subject to compliance with the EU cap and floor). ⁸³
Balancing services charges: payments from suppliers (Embedded Benefit 2)	By reducing a supplier's net demand, Smaller Distributed Generation and exporting on-site generation can receive payments for reducing suppliers' liabilities for balancing services charges. This is being addressed by the Embedded Benefits reforms in this TCR decision. Non-exporting on-site generators can receive the same benefits. This will be considered by the second Balancing Services Charges Taskforce.
Balancing services charges: avoided charges (Embedded Benefit 3)	Smaller Distributed Generation and on-site generation currently does not pay generation balancing services charges. This will be considered by the second Balancing Services Charges Taskforce.

Table 8 Summary of the 'non-location' Embedded Benefits identified for reform

The minded-to consultation

⁸³ The EU cap and floor refers to European regulation 838/2010 which states that 'Annual average transmission charges paid by producers in each Member State shall be within the ranges set out....', for which Ireland, Great Britain and Northern Ireland is the range from 0 to 2.50 EUR/MWh. In Great Britain, 'producers' are the larger generators - transmission-connected and larger distribution-connected generators (above 100 MW) - but excludes Smaller Distribution Generators (which are currently treated as negative demand for the purposes of transmission charging).

4.5. We proposed, in our minded-to consultation, reforms to the main remaining nonlocational Embedded Benefits, which result in differences between the revenues or costs of Smaller Distributed Generation (and on-site generation) and larger generation. These differences do not reflect a difference in the value provided or cost imposed on the system.

4.6. Figure 7 shows the two reform options we considered in the minded-to consultation. Both reform options included setting the Transmission Generation Residual to zero, subject to compliance with the EU Regulation. This follows from the changes we are making through the residual charges being placed on final demand consumers only, so that generation should not be liable for residual charges. This would have the effect of removing a payment to larger generators and removing the disbenefit to Smaller Distributed Generators and on-site generators (as it is currently a negative charge, and payment is credited to larger generators). 'Partial reform' also included removing the ability of Smaller Distributed Generation and exporting on-site generation to offset Suppliers' demand, which reduces the Suppliers' liability for balancing services charges (by measuring the gross, rather than net, volume of electricity at the Grid Supply Point). The 'full reform' proposal included both of these reforms and also proposed making Smaller Distributed Generators and exporting on-site generation liable for balancing services charges, in line with larger generators who currently pay these charges.

4.7. The options for implementation of the reforms proposed in the minded-to consultation were either 2020 or 2021.

Figure 7 Components of partial and full reform in the minded-to consultation

Partial Reform (Includes Embedded Benefits 1 and 2) 1. Set the **Transmission Generation Residual to zero** (subject to compliance).

2. Smaller distributed generators will not be able to offset supplier's liability for balancing services charges (and get paid for doing so). This leads to the same gross metering of a supplier's customer demand now in place for the Transmission Demand Residual following the 2017 decision on Embedded Benefits (CMP264/5).

1. Set the **Transmission Generation Residual to zero** (subject to compliance).

2. Smaller Distributed Generators **will not be able to offset supplier's liability for balancing services charges** (and get paid for doing so). This leads to the same gross metering of a supplier's customer demand now in place for the Transmission Demand Residual following the 2017 decision on Embedded Benefits (CMP264/5).

3. Smaller Distributed Generators would be liable to pay balancing services charges

Full Reform (Includes Embedded Benfits 1,2 and 3)

The decision-making framework

4.8. The TCR launch document stated that the other 'non-locational' Embedded Benefits would be reviewed during the SCR and that if evidence emerged that they led to significant distortions and consumer disbenefits, we would consider whether action would be in consumers' interests.⁸⁴ As we outlined in the minded-to consultation, our analysis has indicated that there is sufficient basis for further action.

4.9. The key purpose of the review of Embedded Benefits was to reduce harmful distortions which impact competition and the efficiency of the electricity market. Our decision-making framework is aligned with the approach for the SCR as a whole. This was to make a principles-based assessment of the options, supported by wider systems analysis

⁸⁴ <u>https://www.ofgem.gov.uk/system/files/docs/2017/08/tcr_scr_launch_letter.pdf</u>

which our consultants advised on and undertook. A summary of the assessment of the options against the TCR principles is set out below.

4.10. The TCR principles and their application to reforming the remaining non-locational Embedded Benefits have been considered in the context of ensuring that we meet our principal objective and statutory duties.⁸⁵

Reducing harmful distortions

4.11. In the minded-to consultation, we said that reducing harmful distortions was a major consideration for reform of Embedded Benefits and the distortions we were concerned about were described in detail.⁸⁶ These included:

- Directly increased consumer costs: where some generators do not pay residual charges, the charges have to be recovered either from consumers overall through a higher per unit charge, or from other generators. Where Smaller Distributed Generators (and exporting on-site generation) receive payments for helping suppliers reduce their residual and/or balancing services charges (or receive payments directly from NGESO), or where larger generators receive a transmission residual payment, these payments are added onto consumer bills. Where higher per unit balancing services charges are levied on other generators, these charges will be largely passed through to consumers via wholesale costs (as set out below).
- Wholesale price and dispatch: where an Embedded Benefit is received based on the amount of electricity generated, there is a distorted incentive for those receiving the benefit to run "out of merit" (generate ahead of lower cost generators) and hence distort dispatch. This has the effect of increasing the system costs for consumers and failing to send efficient signals to the generators that should be running. This potentially also changes the balance between imports and exports on interconnectors (interconnectors do not pay balancing services charges).

 ⁸⁵ As set out in the section 3A to 3E of the Electricity Act 1989 and the section 149 of the Equality Act 2010.
 ⁸⁶ <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 5 - reform to non-</u>

https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 5 - reform to locational embedded benefits.pdf.

- Capacity Market (CM):⁸⁷ Capacity Market prices are set by means of an auction through which eligible generation, interconnectors, storage and DSR enter bids for the fixed annual payment they require, to either keep open an existing facility or build new capacity. Embedded Benefits that provide additional revenue can distort Capacity Market bids, increasing the apparent competitiveness of the facility and hence making it more likely to clear in the auction, at the expense of capacity which is more cost-effective.
- Contracts for Difference (CfDs): low carbon generators bid for CfDs in the CfD allocation process. Those generators receiving an Embedded Benefit may be able to bid a lower price, and hence receive CfDs ahead of other more cost-effective generation and distort awarded strike prices.⁸⁸
- Ancillary services: Embedded Benefits will lead to some parties having a competitive advantage when bidding for ancillary services contracts, as those receiving Embedded Benefits may be able to bid at lower prices.

4.12. The impact of Embedded Benefits is to provide additional revenue to some generators, although there is no benefit to either end users, or to the network. As a result, the generators which benefit from this are then able to use this income to appear more competitive when, in fact, they are not. The result of this is to provide a competitive advantage through Embedded Benefits and to leave generation which is more efficient and better for the system as a whole at a disadvantage. Over time this has the effect of distorting generation in favour of generation which can exploit this charging regime rather than the most efficient and competitive generation. Taking this to its extreme conclusion would mean that generation becomes less efficient overall and more expensive at a time when our system needs to become as efficient as possible to meet the challenges of a low carbon future.

4.13. Only through a system which encourages the most efficient forms of generation, competing on a level playing field, can there be targeted support in order to encourage any specific types of generation, as deemed appropriate through government policy. If the

⁸⁷ The Capacity Market was suspended following a legal challenge. It has since been reinstated but we undertook a sensitivity analysis to consider the reforms if the Capacity Market was not in place. There are more details in Chapter 5, Quantifying the benefits of reform.

⁸⁸ Strike prices are the prices a generator is guaranteed to receive under the CfD contract (subject to the contractual adjustments) over the contracts lifetime.

charging system has distortions such intervention is less effective, and likely to be more costly. Our view is that network charges for generation should reflect the costs that generators impose on the system and Embedded Benefits distort charges from delivering this basic principle.

Fairness

4.14. As we set out in both the TCR launch statement and Annex 5 of the minded-to consultation, we are considering 'fairness' as it applies to, and between, end-consumers (and by extension, charges to suppliers as a proxy for fairness to consumers)'.⁸⁹ We think that reasonable treatment of generators is appropriately covered under our 'reducing distortions' principle, which will facilitate a more level playing field between competing generators, and under proportionality and practical considerations. We have considered the impacts of change on final demand consumers when taking our final decision.

Proportionality and practical considerations

4.15. We considered and assessed the 'partial' and 'full' reform options in the minded-to consultation based on their practicality, the likely implementation cost (at a high level) and hence the overall proportionality of the change. We set out this assessment, and concluded that 'the options considered generally constitute a low level of industry change (from the perspective of practicality and cost) relative to the changes to the charging of transmission and distribution residuals, and hence practicality and implementation cost are less likely to be critical factors' in reaching our decision.⁹⁰

4.16. We have again considered proportionality and practicality of the options in our principles based assessments and have given due consideration to both the practical changes this requires and the overall assessment of high-level costs given that the first Balancing Services Charges Taskforce concluded that balancing services charges should be treated as cost-recovery charges. We have also considered the potential for volatility of charges to both generation and consumers given their conclusions. Our views on the

⁸⁹ The Launch Statement can be found here:

<u>https://www.ofgem.gov.uk/system/files/docs/2017/08/tcr_scr_launch_letter.pdf</u> and Annex 5 of the minded-to document can be found here:

https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 5 - reform to nonlocational embedded benefits.pdf.

⁹⁰ <u>https://www.ofgem.gov.uk/system/files/docs/2018/11/annex 5 - reform to non-</u>locational embedded benefits.pdf.

proportionality and practical considerations of the three elements of Embedded Benefits reform are:

- Setting TGR to zero this will require:
 - the implementation of the correct interpretation of the 'connection exclusion' for EU Regulation 838/2010 into the transmission charging methodology, and/or
 - setting the TGR to zero through the TCR direction (subject to compliance with the EU Regulation 838/2010).
- The first step is required to ensure the codes reflect the correct interpretation of the EU Regulation 838/2010. The second step is relatively straightforward to implement and has provision for the implementation of an 'adjustment factor' if step one is not completed in a timely manner.⁹¹ For the avoidance of doubt, this should be achieved by charging generators all applicable charges (having factored in the correct interpretation of the connection exclusion as set out in 838/2010), and adjusted if needed to ensure compliance with the 0-2.50 EUR/MWh range.
- Removing payments related to balancing services charges to Suppliers this will require changes to the codes and settlement systems. This change is relatively straightforward to implement since this change has already been designed and implemented for Transmission Demand Residual charges through CMP 264/265.
- Requiring Smaller Distributed Generators (and exporting on-site generators) to pay balancing services charges for generators – this would be a more substantial change since currently Smaller Distributed Generators and on-site generators are not required to accede to the CUSC and do not hold Transmission Entry Capacity (TEC). Arrangements would need to be developed to define the transmission access rights that Smaller Distributed Generators and onsite generators hold and to charge them on a similar basis as larger generators. These changes would be justified if these payments

⁹¹ The EU Regulation 838/2010 states that 'Annual average transmission charges paid by producers in each Member State shall be within the ranges set out....', for which Ireland, Great Britain and Northern Ireland is the range from 0 to 2.50 EUR/MWh. In Great Britain, 'producers' are the larger generators - transmission-connected and larger distribution-connected generators (above 100 MW) but excludes Smaller Distribution Generators (which are currently treated as negative demand for the purposes of transmission charging).

were likely to continue for a significant period of time; however, we have concerns as to the proportionality of mandating such changes given the ongoing work of the taskforce in relation to which there is a real possibility that they might propose the removal of balancing charges from all generators. If such a proposal was (following consultation) implemented in the relatively short term this would likely result in volatility of charges. In addition, the second taskforce will consider distortions related to the treatment of onsite generation. If liability for balancing services charges were implemented for all generators, then subsequently removed by a resulting modification from the second taskforce it would cause volatility of charges for both generation and consumers.

4.17. This is shown in our updated assessment in Table 10, later in this chapter.

Additional work since the minded-to consultation

The Balancing Services Charges Taskforce

4.18. In parallel with the minded-to consultation, we launched the first Balancing Services Charges Taskforce. Its overall objective was 'to provide analysis to support decisions on the future direction of balancing services charges'.⁹² We said, in the minded-to consultation, that we would 'consider the conclusions from a taskforce on balancing services charges and decide if other changes to these charges should be taken forward in parallel with, or subsequent to our proposed changes to balancing services charges'.⁹³ Details of the taskforce and its conclusions can be found at the Charging Futures website.⁹⁴

4.19. The taskforce concluded, after consultation, that balancing services charges do not send useful cost-reflective signals and should be treated as cost-recovery charges, stating:

it is not feasible to charge any of the components of balancing services in a more costreflective and forward-looking manner that would effectively influence user behaviour that

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https://www.ofgem.gov.uk/system/files/docs/2018/11/decision to launch a balancing services cha rges taskforce.pdf

⁹³<u>https://www.ofgem.gov.uk/system/files/docs/2018/11/targeted_charging_review_minded_to_decisi_on_and_draft_impact_assessment.pdf</u>

⁹⁴ <u>http://www.chargingfutures.com/charging-reforms/task-forces/balancing-services-charges-task-force/what-is-the-balancing-services-charges-task-force/</u>

would help the system and/or lower costs to customers. Therefore, the costs included within balancing services charges should all be treated on a cost-recovery basis'.⁹⁵

4.20. Given our decision that residual charges (which are also cost-recovery charges), should be paid by final demand consumers we think further work is needed to consider who should pay balancing services charges and how the charge should be designed.

Further consultations

4.21. In May 2019, we published an open letter which provided updates on the timeframes for the TCR.⁹⁶ Primarily, this was because of the suspension of the Capacity Market. We thought it was prudent to consider the robustness of our reforms to the continued absence of the Capacity Market and to consult with stakeholders as to their views on the analysis. The Capacity Market has recently been reinstated.⁹⁷

4.22. In June 2019, we published a consultation considering the robustness of the modelled outcomes of the TCR reforms should the suspension of the Capacity Market continue.⁹⁸ This letter also provided information on the findings of the Balancing Services Charges Taskforce and said that we would welcome stakeholder feedback with respect to its findings and how they should be considered within the context of our minded-to consultation.

4.23. In this same letter, we provided updated carbon values as we recognised that our consultants did not use the correct carbon values for the assessment of the carbon emissions for the Transmission Generation Residual and balancing services charging reforms. We published the amended backing data for the assessment of the Transmission Generation Residual and balancing services charges reform options alongside this open letter.

⁹⁵ <u>http://www.chargingfutures.com/media/1330/balancing-services-charges-task-force-draft-report.pdf</u>

⁹⁶ <u>https://www.ofgem.gov.uk/system/files/docs/2019/05/may_charging_open_letter_final_21-may.pdf</u>

⁹⁷ The official report regarding the suspension of the Capacity Market ending is not yet published. This is a link to the letter from the commission explaining the decision

https://ec.europa.eu/competition/state_aid/cases1/201945/278880_2105752_352_2.pdf ⁹⁸ https://www.ofgem.gov.uk/system/files/docs/2019/06/tcr_consultation_june19_final.pdf

4.24. We published a further consultation in September 2019, which sought views on banding of non-domestic consumer groups for the residual charges reform.⁹⁹ Alongside this, we published the results of a sensitivity analysis our consultants undertook to consider how our reforms might be affected if a significant number of renewable generators were not built in the way anticipated by the Future Energy Scenarios, which formed the basis of our wider systems analysis.¹⁰⁰

4.25. The responses to the minded-to consultation and draft impact assessment, the supplementary consultations and open letters are discussed below.

Stakeholder views

Principles-based assessment

4.26. We used the TCR principles of reducing harmful distortions, fairness, and proportionality and practical considerations to undertake a principles-based analysis of our reform options. This led us to consult on two options: partial reform and full reform, with full reform as our leading option. The reform options were considered quantitatively through the wider systems analysis, which our consultants undertook.

4.27. Most stakeholders were supportive of the TCR principles, and their application, but some raised concerns regarding the application of the TCR principles to balancing services charges.

4.28. Some respondents questioned whether all generation should be treated equally, suggesting that differential treatment can be acceptable. For example, some suggested that renewable generation should be favoured by the charging arrangements because it is needed to meet carbon targets. One respondent questioned our approach to fairness, suggesting we should have applied fairness for all network users. This is because the reforms could have a negative impact on some investments, potentially affecting consortia, including pension funds, and therefore impact consumers.

⁹⁹ https://www.ofgem.gov.uk/system/files/docs/2019/09/tcr open letter sep 19.pdf

¹⁰⁰ See chapter 5, Quantifying the benefits of change for further information regarding the Future Energy Scenarios we used

4.29. We have considered all responses to each of our consultations. In our view, it is expected that when investment decisions are made, following due diligence. We have clearly and consistently signalled our concerns about the existence of Embedded Benefits and our plans for reform since 2016.¹⁰¹ Network charges are subject to open governance meaning that the possibility of change cannot be discounted. Hence, it is expected that the potential for change should be factored into business cases accordingly. Our wider systems analysis shows that targeted support for specific types of generation provides more efficient outcomes and is a lower cost option for consumers, than the current, non-targeted (and implicit) support for most generation, which, as explained above, causes a number of distortions.

4.30. Some respondents also questioned the 'fairness' implications with regard to applying balancing services charges to Smaller Distributed Generators (which would occur under the full reform option). This would make them less competitive with respect to interconnector imports of electricity from European Union Member States (which are not liable for balancing services charges). As stated above, we think that this distortion should primarily be considered under the principle of reducing harmful distortions rather than fairness. We also note that this distortion highlights the advantage for Smaller Distributed Generators who, like interconnectors, do not currently pay balancing services charges whereas larger generators do. Lastly, We disagree that residual charges are there to compensate generators for differences in the forward looking charges. We are reviewing the forward looking charging for all network users in the Access project, and we will consider the implications of these charges for competition between GB and interconnected generation as part of this work. We have considered this when taking our final decision on the TCR.

4.31. In general, consultation respondents agreed with the view that both partial and full reform would reduce distortions. Some did not agree that the distortions which result from the current system of Embedded Benefits were harmful, suggesting that these 'benefits' were necessary for some types of generation to be economic. Some argued that the residual charge was providing important revenue streams to renewable generators.

4.32. This assertion is not consistent with the wider systems analysis we have undertaken, which shows that the current system of Embedded Benefits is providing revenue streams to all generators, and that by removing these, consumer benefits would be realised. We do

¹⁰¹ <u>https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter - charging_arrangments_for_embedded_generation.pdf</u>
not consider that Embedded Benefits reflect cost savings to the network and they distort competition as we have described above. Our analysis indicates that replacing these payments with targeted payments to bring forward new low carbon generators can deliver the same level of decarbonisation at lower costs to consumers.

4.33. Our view is that, in principle, all generation should face network charges which reflect the costs that they impose on the system. If specific types of generation technology require additional support, to meet renewables targets for example, our view is this should be through explicit subsidy, not through distortions in network charges. Our wider systems modelling supports this position.

4.34. We have applied the TCR principles to Embedded Benefits in the same way as we have to residual charge reform. A revised principles-based assessment, which includes the taskforce findings, other feedback and work undertaken since the minded-to consultation is included later in this chapter (Table 10).

Wider systems analysis

4.35. We commissioned consultants to conduct a wider systems analysis to model the potential changes to the electricity system as a whole, considering different potential energy futures, without and with our reforms in place. Respondents generally supported the rigorous approach we took to the wider systems analysis, although there were some specific issues raised which are discussed below. Chapter 5 provides a more detailed commentary on the wider systems analysis, its assumptions and the initial and subsequent modelling undertaken by our consultants.

Impact on renewable generators

4.36. Some responses to the minded-to consultation were particularly concerned about how the modelling represented the impact of the Embedded Benefit reforms on renewable generators. Some stakeholders were concerned about how the model determines the amount of renewable generation in the generation capacity mix. In the modelling published with our minded-to consultation, the renewable deployment was set as an exogenous assumption using two of National Grid's Future Energy Scenarios, following the approach recommended by our consultants.¹⁰² This modelling recognised that reform of the nonlocational Embedded Benefits would impact revenues of grid connected generation, and assumed that the Government's CfD support payments for new build generators would adjust to maintain the renewable buildout in the reform scenarios.¹⁰³ Some stakeholders said that the proposed reforms would lead to less renewable generation being built, which would reduce potential consumer savings and increase carbon emissions making them contrary to Ofgem's objectives.

4.37. We do not agree with this view. We have considered our principal objective and statutory duties in the round. Our principal objective is to protect the interests of current and future energy consumers, including their interests taken as a whole in relation to the reduction of greenhouse gases, and in the security of the supply of gas and electricity to them.¹⁰⁴ Maintaining distortive network charges in order to provide support to low carbon generators is an inefficient and expensive approach to supporting decarbonisation of the energy system.

4.38. The wider systems analysis indicates that our decision (comprising reform of residual charges and Embedded Benefits) will reduce carbon emissions overall. Our modelling does indicate that changes to Embedded Benefits on their own (under partial reform) might increase carbon emissions by up to 1% (depending on the Future Energy Scenario used). It should be noted that the outcome of the modelling is affected by emissions from increased GB domestic generation which is at the expense of interconnectors importing electricity from other countries. This is because carbon accounting is carried out for the country in which the power is generated, and there is no value associated with imported power. Further information regarding carbon emissions can be found in Chapter 5.

4.39. Removing the distortions in the current charging regime to provide a more level playing field for all generation provides savings for consumers. With targeted support,

¹⁰² Information on National Grid's Future Energy Scenarios is available here: <u>http://fes.nationalgrid.com/fes-document/.</u>

¹⁰³ The Future Energy Scenarios provide potential future energy landscapes. They have differing capacity mixes, rates of decentralisation and consumer engagement amongst other features. More information can be found at the website <u>http://fes.nationalgrid.com/.</u>

¹⁰⁴ As set out in the section 3A to 3E of the Electricity Act 1989 and the section 149 of the Equality Act 2010.

rather than implicit subsidy through charges, we consider that decarbonisation can be implemented at a lower cost to consumers.

4.40. Aurora undertook analysis of the TCR proposals, which concluded that the implementation of full reform would impede unsubsidised renewable deployment by two to five years.¹⁰⁵ Again, further information on our assessment of this analysis can be found in chapter 5.

4.41. Oxera were commissioned by a small group of stakeholders to provide analysis of our proposals. This analysis considers what would happen if the number of new onshore wind and solar generators was reduced to zero, which we consider to be unrealistically low levels. They suggest this would significantly affect the government's ability to meet its legally binding carbon targets by reducing the viability of these technologies. Further information on this analysis can be found in Chapter 5.

4.42. We think it is difficult to draw meaningful conclusions from Oxera's analysis, which shows a 100% reduction in onshore wind and solar build, since:

- Evidence provided through consultation responses does not indicate we should expect to see such a significant reduction in investment in these technologies.
- Our behavioural assessment indicates investment in small-scale renewable generation is not always solely driven by profit.
- Aurora has subsequently published analysis which indicates that combined solar and storage installations are becoming investable without subsidy.¹⁰⁶

4.43. Prudent investors will be aware that changes to network charges are possible either through the open governance process or Ofgem-led reviews. Investors, and the generation businesses they invest in, will also be aware of the previous Embedded Benefits decision and our plans to undertake further reforms. Many important factors influence these decisions, such as the speed of levelised cost reductions, and we consider it likely that the TCR reforms will be less significant than the other drivers of investment in theonshore wind and solar industry.

 ¹⁰⁵ <u>https://www.auroraer.com/wp-content/uploads/2019/05/Aurora-TCR-Public-Report-May-2019.pdf</u>
 ¹⁰⁶ <u>https://www.auroraer.com/insight/economics-merchant-solar-battery-colocation/</u>

4.44. Notwithstanding our view that 100% reductions in these renewable technologies is unlikely, we have carefully reviewed this additional information and, following discussions with our consultants, they have undertaken an assessment to understand how sensitive our consumer benefits are to a reduction in onshore wind and solar buildout.

4.45. Importantly, the modelling assumed that successive governments will act over time to ensure they meet decarbonisation targets. This is in line with normal practice for impact assessments by government departments. So, in our model, CfD strike prices change to ensure the level of renewable buildout needed to meet the Future Energy Scenarios still occurs. The government stated after we published our minded to consultation, that AR3 (the 2019 CfD auction round) would not provide funding for onshore wind or solar technologies and we wanted to test our consumer benefits case against the continuation of this policy. As such, we have examined a relatively unlikely sensitivity analysis in which we consider if our consumer benefits would be robust to a 50% reduction in the level of new unsubsidised onshore wind and solar generation, which is replaced by CfD-supported offshore wind. This would reduce the consumer benefit, because the total subsidies to offshore wind are assumed to be more expensive. However, a substantial consumer benefit would remain with an NPV ranging from £1.9bn to £3.5bn (combined consumer benefits from residual charges and full Embedded Benefit reform).

4.46. We published this supplementary analysis on 3 September 2019, alongside some further analysis on our residual charge proposals. We received 50 responses, of which about 20 commented on the renewable sensitivity analysis. There were mixed views on whether the rate of reduction of solar and onshore wind was appropriate, with some believing the 50% rate was too high and others believing it was too low. More of the respondents suggested that a 50% reduction remained too low and suggested that we did not fully recognise the impacts of these reforms. Those who thought the rate was too low suggested that our proposals would damage the progress made towards decarbonisation because in their view, onshore wind provides the lowest cost renewable generation.

4.47. We disagree with the view that the TCR decision will result in UK failing to meet decarbonisation targets for the electricity system. We believe that the 50% reduction was a reasonable sensitivity test to undertake, as set out in our consultation.¹⁰⁷ The 50% sensitivity tests the loss of revenue associated with the full balancing services charging

¹⁰⁷ <u>https://www.ofgem.gov.uk/system/files/docs/2019/09/wider_system_modelling_-</u> <u>renewable_sensitivites_-2019-08-30.pdf</u>

reform scenario – representing a loss of £5/MWh of revenue for smaller distributed generation. When considering the extent of the potential reduction in onshore wind and solar, we have considered two key variables: the financeability of current unsubsidised renewable investment and various bodies' forecasts for expected falls in technology costs. Some of whose estimates (including those of the Solar Trade Association) show levelised costs of energy falling significantly beyond this £5/MWh loss of revenue in coming years.¹⁰⁸

4.48. This analysis is designed to test the robustness of our analytical assessment to what we consider to be a reasonable sensitivity to undertake. The analysis was also undertaken before the results of the last CfD auction were published.¹⁰⁹ This auction resulted in offshore wind and remote island wind strike prices of ~£40 per MWh, considerably lower than those used in our sensitivity analysis of £57.50 per MWh. This might suggest that the loss of consumer benefits is likely to be smaller than that described in our sensitivity analysis.

4.49. The Future Energy Scenarios have a range of implicit assumptions built into them about subsidies for renewable technologies. Given this, our consultants continue to advise that this is the correct approach for assessing wider system impacts, given that they explicitly show the change in subsidies needed to result in the equivalent buildout of different renewable technologies.

4.50. There was concern from some stakeholders that strike prices would need to increase to cover existing and new generators' lost revenues, following these reforms, as there was potential for generators to try to renegotiate their CfD contracts. As we stated in our minded-to consultation, we expect generators bidding in to future CfD rounds to adjust their bids accordingly, and we expect generators who already hold CfD contracts to have taken account of the potential for changes to network charges over time but we do not expect those with existing renewable support to be able to renegotiate their subsidy arrangements.¹¹⁰

¹⁰⁸ <u>https://www.solar-trade.org.uk/cost-of-uk-large-scale-solar-could-drop-below-40mwh-by-2030/</u>
¹⁰⁹<u>https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/fil
<u>e/832924/Contracts_for_Difference_CfD_Allocation_Round_3_Results.pdf</u></u>

¹¹⁰ There are small adjustments made to strike prices annually. These are explained in the guidance released by the Low Carbon Contracts Company. This includes a Balancing Settlement Charge Adjustment. More information is available at

https://www.lowcarboncontracts.uk/sites/default/files/Strike%20Price%20Adjustment%20guide%20fi nal%20JR.pdf

4.51. Merchant renewable generators, who are currently unable to bid for CfD contracts, have presented concerns about these reforms because they cannot recoup lost revenue through CfD contracts or the Capacity Market, but we have not seen any evidence that changes our view of the benefit to consumers and the system as a whole.

4.52. Some stakeholders raised concerns about these reforms having a negative impact on investor confidence, with stakeholders suggesting that their expected rates of return would be significantly reduced, citing reductions of 3% or more, or that income would be reduced by up to £8 per MWh.

4.53. Whilst the wider systems analysis has inbuilt assumptions which consider standard commercial practices and take these into account, we have separately examined the question of investment in generation.¹¹¹ In particular, we have considered:

- Required rates of return the minimum rate acceptable to an investor to put money into a project (the hurdle rate).
- Expected rate of return the amount of return an investor expects to receive from a project invested in.
- Actual rate of return the amount of return an investor realises on their investment.

4.54. The required rate of return is linked largely to the risk, whether perceived or real, associated with any investment. In simple terms, the greater the risk, the higher the required rate of return. We have acknowledged that there is a period of uncertainty whilst the TCR and Access and forward looking charges SCRs are underway. We have said that whilst we cannot provide certainty of the outcomes of future decisions, we can offer regulatory certainty as far as possible regarding this decision, and we believe that this decision will reinforce predictability.

4.55. We undertook some high-level financial modelling which estimates rates of return and calculated the potential reduction in actual rates of return as shown in Table 9. For both setting the Transmission Generator Residual to zero, and the removal of Smaller Distributed Generators' ability to receive benefits from offsetting a Supplier's demand and reducing their balancing services charges, the impact is (in aggregate) just under 1%.

¹¹¹ See the Quantitative analysis chapter for more information regarding the model and the assumptions within it.

Reform option	Potential reduction in revenue per MWh	Likely reduction in actual rate of return
Transmission Generator Residual set to zero (subject to compliance with EU Regulation 838/2010)	£2.30	0.8%
Partial Reform (TGR to zero (subject to compliance) plus removal of the ability to offset Suppliers' balancing services charges)	£2.50	0.9%
Full Reform (TGR to zero (subject to compliance) plus Partial Reform (as above) plus removal of the exemption from Smaller Distributed Generators for paying balancing services)	£5.00	1.8%

Table 9 Estimated potential decrease in rate of return for generation under reform options

4.56. Some stakeholders raised concerns that uncertainty about network changes is causing required rates of return to increase. Whilst uncertainty is a factor in most investment decisions and we acknowledge there is uncertainty around network charges as there are two ongoing SCRs network charges will always be subject to potential change because they are subject to open governance under industry codes. As such, we would expect that business and investment cases would have taken account of potential changes.

4.57. We recognise that, by removing these distortions, income at some sites will be reduced. However, our role is to consider these changes across the system as a whole, and what best facilitates our principal objective. Even if this income has been used for business and investment cases, there has been clear and consistent signalling of these reforms since our review of Embedded Benefits in 2016.¹¹²

4.58. In our minded to decision we said:

¹¹² <u>https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_</u> <u>charging_arrangments_for_embedded_generation.pdf</u>

During our assessment of Embedded Benefits last year (part of CMP264/5), we considered the likelihood that changes to system and network charging arrangements would lead to a subsequent increase in the cost of capital across the industry. We have considered the same issues as part of the TCR and we do not consider any increase in cost of capital to be likely, as potential for change in charging arrangements is well established. [...] This is because changes in charges should be factored in, with regulatory reviews being well established. We also do not expect there to be any increase in risk across the industry. Non-discriminatory arrangements, such as those we are proposing, are more conducive to a stable, neutral investment environment where investments are focused on creating value that is aligned with system benefits, and not solely on avoiding residual charges. We consider that any impacts on investment are proportionate and justified by the consumer and system benefits.

4.59. We still consider this to be the case and have not received any evidence to change this view. We are satisfied that costs will not increase significantly or erode the expected consumer benefits significantly. The potential for these changes, both setting the Transmission Generation Residual to zero (subject to compliance with the EU Regulation 838/2010) and removing the Embedded Benefits related to balancing services charges, have been signalled for a considerable length of time.¹¹³ We would expect that prudent investors are expecting or anticipating that such changes could be introduced, and will have factored them into their decision making.

Interactions with the Capacity Market

4.60. On 15 November 2018, the General Court of the Court of Justice of the European Union annulled the European Commission's state aid approval for the Capacity Market in Great Britain. Whilst we understood that the Government expected the reinstatement of the Capacity Market (as is now the case), we thought it useful and prudent to model a scenario without the Capacity Market in place, to test the sensitivity of our projected impacts to this unlikely outcome. This modelling showed that the reforms would continue to deliver

¹¹³ The EU Regulation 838/2010 refers to European regulation 838/2010 which states that 'Annual average transmission charges paid by producers in each Member State shall be within the ranges set out....', for which Ireland, Great Britain and Northern Ireland is the range from 0 to 2.50 EUR/MWh. In Great Britain, 'producers' are the larger generators - transmission-connected and larger distribution-connected generators (above 100 MW) - but excludes Smaller Distribution Generators (which are currently treated as negative demand for the purposes of transmission charging).

substantial consumer benefit even if a Capacity Market was not in place. The Capacity Market has since been reinstated.

4.61. We published an open letter in June 2019 including this analysis.¹¹⁴ Consultees generally agreed it was a prudent exercise, and agreed with our assumptions. Of the 11 respondents two stated that they agreed that our proposals were still beneficial using a scenario where the Capacity Market was no longer in place. Three respondents stated they did not think that the analysis showed that our reforms were still beneficial to consumers in the same scenario. The other respondents did not express a view regarding outcomes.

Interactions with Balancing Services Charges Taskforce

4.62. Many stakeholders agreed that we should wait for the Balancing Services Charges Taskforce to report its findings before we made a final decision on the TCR. We said we would do this in the minded-to consultation and we have taken the taskforce findings into account in our decision.

4.63. in our open letter published in June 2019, we provided an opportunity for stakeholders to comment on the findings of the taskforce and how they should be considered within the context of our final decision. There were 19 respondents to this letter. None of the respondents raised objections to the taskforce findings being used to inform the SCR. Eight respondents said this should lead us to select the partial reform option, some of whom suggested this should be treated like the residual charge.

4.64. As set out above, when we consulted on the findings of the taskforce, generally respondents indicated that, as balancing services were concluded to be cost recovery charges by the taskforce, we should implement partial reform.

4.65. This is because during the SCR we have said that residual charges, which are costrecovery charges, should be paid by final demand consumers only and set out the reasons for this, in the TCR working paper published in 2017.¹¹⁵ This stems from our conclusion that distortions to the effects of the cost-reflective signals can be reduced by placing residual charges onto demand users only.

¹¹⁴ https://www.ofgem.gov.uk/system/files/docs/2019/06/tcr consultation june19 final.pdf ¹¹⁵ https://www.ofgem.gov.uk/system/files/docs/2017/11/tcr working paper nov17 final.pdf

4.66. We also provided an opportunity for stakeholders to comment on the findings of the first taskforce and how residual charges are used to ensure that the network companies can recover their allowed revenues set through RIIO price controls. Once forward-looking charges have been levied, the remainder of the allowed revenue is collected, and are hence considered cost recovery charges. Balancing services charges allow the ESO to recover its costs for balancing the system. The Balancing Services Charges Taskforce concluded that useful forward-looking signals could not be sent through balancing services charges and they should be treated as cost-recovery charges. We accept this view and recognise that by launching the second taskforce to apply the TCR principles to balancing services charges, it is possible that a recommendation is made that liability for these charges may be placed onto demand consumers only. If liability for balancing services charges were implemented for all generators, then subsequently removed by a resulting modification from the second taskforce it would cause volatility of charges for both generation and consumers.

4.67. The further implications of launching the second taskforce on the two Embedded Benefits related to balancing services charges are:

- the second taskforce may conclude that balancing services charges should be recovered in the same or similar manner to the new transmission and distribution residual charges being implemented by this decision. This is because the first taskforce concluded that balancing services charges are cost-recovery charges, the same type of charge as residual charges. This could mean that balancing services charges are recovered entirely from final demand consumers and on a fixed or similar basis. If this was to occur, both the Embedded Benefits associated with balancing charges would be addressed, as payments in relation to avoided Supplier charges would no longer be likely, and no form of generation would be liable for balancing services charges.
- however, it is not yet certain that this will be the conclusion. We will consider any
 modifications that come forward on the basis of the second taskforce on their merits
 and do not presume an outcome at this stage. Therefore, at this stage, we need to
 consider what is the most appropriate course of action given that it is possible, but not
 certain, that the second taskforce may lead to changes which would address both of
 these Embedded Benefits. It is also not yet certain what the implementation date will be
 for any changes coming out of the second taskforce. We have asked the taskforce to
 consider the best interests of all market participants when assessing the
 implementation of any changes.

- having considered this situation carefully, we have concluded ther is meritto bringing forward the necessary changes under the TCR direction to remove the payments to generators related to reduction of balancing charges on suppliers, as this change is relatively straightforward to implement and these payments add directly to consumer bills. Also, it is very unlikely that the second taskforce will re-introduce payments to generators, due to the conclusions of the first task force that these should be treated as cost recovery charges. Hence the removal of payments related to balancing charges is not likely to be reversed by subsequent changes arising from the second taskforce.
- however, the changes required to levy balancing charges on Smaller Distributed Generators and to consider the treatment of on-site generators is a much more complex undertaking. In addition, it is quite possible that changes coming from the second taskforce may result in balancing services charges being removed from all generators. Hence requiring Smaller Distributed Generators to pay balancing charges when we can envision an outcome that no generators will pay these charges, could cause charging volatility.

4.68. As such, we have concluded that we should implement partial reform through this SCR as a first part of a stepped change, noting that further work is being undertaken to determine how balancing services charges should be designed. In our view, the alternative of implementing full reform could potentially cause significant disruption, volatility of charges and unnecessary implementation costs.

4.69. In order to do this, we are asking the ESO to launch a second Balancing Services Charges Taskforce with the aim of determining who should pay for, and the design of, balancing services charges in line with the TCR principles. We have also asked the taskforce to consider the implementation any changes within a timeframe which balances the interests of all market participants.

4.70. We expect the taskforce to report its findings early in 2020 and that the ESO will raise modifications to provide for implementation of any resulting changes to balancing services charges.

Principles-based assessment: the decision

4.71. We have considered the application of the TCR principles to reforming the remaining non-locational Embedded Benefits in the context of ensuring that we meet our principal

objective and statutory duties.¹¹⁶ The revised application of our principles-based assessment to the two options we considered which takes the additional information discussed into account is shown in Table 10 below.

 $^{^{\}rm 116}$ As set out in the section 3A to 3E of the Electricity Act 1989 and the section 149 of the Equality Act 2010

Table 10 Revised principles-based assessment for reform of Embedded Benefits

	Criteria				
Options	Reducing harmful distortions	Fairness to end consumers	Proportionality and practical considerations		
			Practical considerations & delivery risk	Proportionality: disruption to market participants (excluding consumers)	Proportionality: Short term distributional impact for consumers
A - 2021 - Full Reform	Provides the greatest consistency in charging across all domestic generators, but leaves an outstanding distortion between interconnectors and generators because interconnectors do not pay balancing services charges . This outcome (of greater charge alignment) could be considered contradictory to the reasoning that residual charges and therefore cost recovery charges, should be levied on final demand only, given the Balancing Services Charges Taskforce concluded that balancing services charges should be treated as cost-recovery charges.	Full consumer benefit realised through decision being made now.	Delivery in 2021 allows sufficient time for implementation. However, the outcome of the second taskforce might require some reforms to be altered – reversal of Smaller Distributed Generation paying balancing services charges – therefore potentially complex changes for short term implementation	Quickest reduction in inefficient investment, and there would have been significant notice of change. This may result in a short period of additional charges for Smaller Distributed Generators which may be subsequently removed (depending on the outcome of the second taskforce). This could present a significant disruption to some industry participants, with arrangements in place for only a short period of time. This potentially leads to volatility of charges	All consumers see reduced bills quickly. If balancing services charges are [subsequently] passed on to final demand consumers (being a potential outcome of the second taskforce) this would be likely to increase bills which may lead to greater volatility of charges.

	Criteria				
Options	Reducing harmful distortions	Proportionality and practical considerations			
			Practical considerations & delivery risk	Proportionality: disruption to market participants (excluding consumers)	Proportionality: Short term distributional impact for consumers
B - 2021 - Partial Reform	Removes most of the distortions between smaller and larger generators (but less than full reform). Removes the distortion from Transmission Generation Residual and suppliers reducing balancing services payments through reducing net demand, but leaves in place one of the harmful distortions (Embedded Benefit 3) between generators which we expect to be addressed through a second taskforce Provides a clearer path to removing distortion between interconnectors and domestic generators if the outcome of the taskforce results in all GB domestic generation not being liable for balancing services charges. Most stable outcome given the findings of the first taskforce and further work can be undertaken (as required) should the outcome of the second taskforce not address any remaining distortion.	60-70% of the consumer benefit realised through decision being made now.	Delivery in 2021 allows sufficient time for implementation. Potentially avoids duplication of system changes (depending on the outcome of the second taskforce). It is unlikely that any changes to Embedded Benefit 2 would be reversed by the taskforce but a greater likelihood that charges imposed on Smaller Distributed Generation would be reversed.	Potentially a more gradual reduction in inefficient investment, but there has been significant notice of change No change to the <i>status quo</i> for liability for balancing services charges for generators for a short period whilst the second taskforce undertakes its work. Allows adjustment time for suppliers and generators with respect to any balancing services charges changes recommended by the second taskforce	All consumers see reduced bills quickly but less reduction than under full reform, although this is a step change (The next steps would depend on the outcome of the second taskforce) Potentially mitigates volatility of charges for consumers if result of the second taskforce is to shift all balancing services charges to consumers.

Related Matters

Maintaining compliance with EU regulation 838/2010

4.72. One concern raised by some stakeholders was compliance with European Regulation 838/2010 (Guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging). This states that 'Annual average transmission charges paid by producers in each Member State shall be within the ranges set out...', for which Ireland, Great Britain and Northern Ireland is the range from 0 to 2.50 EUR/MWh.¹¹⁷ In Great Britain, 'producers' are the larger generators - transmission-connected and larger distribution-connected generators (above 100 MW) but excludes Smaller Distribution Generators (which are currently treated as negative demand for the purposes of transmission charging).

4.73. Maintaining compliance with this 'EU cap and floor' has been achieved through a combination of charges and credits for larger generators who are liable for transmission generation charges. The credits have been paid to generators through the Transmission Generation Residual charge.

4.74. As noted above, stakeholders raised questions around how compliance with the cap and floor will be maintained if the Transmission Generation Residual is set to zero and is not available as a mechanism to achieve compliance. Questions were also raised as to what kind of reconciliation process would exist to ensure payments are correct for all generators.

4.75. There is a wider context around this issue. In May 2018, Ofgem made a decision related to how compliance with the cap and floor is determined through CMP261, and this decision was appealed to the Competition and Markets Authority (CMA).¹¹⁸ The CMA upheld Ofgem's decision on CMP261.¹¹⁹

¹¹⁷ https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32010R0838&from=EN ¹¹⁸ https://www.ofgem.gov.uk/system/files/docs/2018/05/cmp261_update_letter_3_may.pdf ¹¹⁹ https://assets.publishing.service.gov.uk/media/5a95295de5274a5b849d3ad0/EDF-SEE-decisionand-order.pdf

4.76. There is currently a Connection and Use of System Code (CUSC) modification at workgroup stage considering EU Regulation 838/2010 which is likely to be impacted by this decision. The CMP317 modification was raised in response to CMP261 and the CMA ruling, which provided some guidance as to how the 'connection exclusion' should be correctly interpreted.¹²⁰

4.77. The CMA ruling, confirmed Ofgem's decision on CMP261 and means that the CUSC is not currently aligned with the correct interpretation of which assets should be included in the 'connection exclusion' for the purposes of the EU cap and floor. The ESO, which has proposed the modification to ensure the CUSC calculates generation charges in accordance with the interpretation of the EU Regulation 838/2010 reflected in CMP261, has included an adjustment mechanism to ensure compliance in the proposal. The industry code working group will also evaluate whether there might be a need for, and consider the design of, any reconciliation should there be a breach of the lower or upper limit of the charging range. Subject to our final decision on this modification, we expect that this would allow the Transmission Generation Residual to be set to zero, resulting in the correct charges and achieving compliance with the EU Regulation 838/2010. We accept that a negative adjustment charge may be required in the future to ensure compliance with the Regulation.

4.78. We said in the minded-to consultation that the ESO is developing a modification which would implement the correct post-CMP261 definition of the EU Regulation 838/2010 range, and would allow us to direct that our policy position of no residuals charged to generation is met.¹²¹ Subject to our final decision on this modification, we currently expect that the correct interpretation of the EU Regulation 838/2010 will be in place in the CUSC by April 2021 in order for the Transmission Generation Residual to be set to zero on this date. If that is not the case, we expect the TCR proposal and subsequent modification to implement the TCR decision to include an appropriate adjustment charge to ensure compliance with the CMP261 interpretation of the Regulation.

¹²⁰ The connection exclusion determines which charges are excluded from the calculation of average generation charges.

¹²¹<u>https://www.ofgem.gov.uk/system/files/docs/2018/11/targeted charging review minded to deci</u> sion and draft impact assessment.pdf

4.79. For the avoidance of doubt, we consider that the CUSC is compliant with EU Regulation 838/2010 except for the interpretation of the 'exclusion connection' which needs to have the correct interpretation, in accordance with the CMA appeal regarding CMP261. We think that generators should face transmission charges for:

- off-shore local charges,
- on-shore local charges (less those which fall into the 'Connection Exclusion'), and
- wider locational charges.

For compliance with the EU Regulation 838/2010 we expect these annual average transmission charges paid by producers to not to exceed €2.50/MWh or fall below €0/MWh. We accept that an 'adjustment charge' may be necessary to rectify this.

Small Generator Discount

4.80. The Small Generator Discount is a scheme which seeks to level the playing field between generators (under 100MW) connected to the 132kV transmission network in Scotland and generators (under 100MW) connected to the 132kV distribution network in England and Wales. A disparity arises because such generators in Scotland connected at 132kV are liable for transmission charges whereas such generators in England and Wales connected at the same voltage are liable for distribution charges. Therefore, Smaller Distributed Generators in England and Wales would be eligible for Embedded Benefits related to transmission charges, whereas similar generators in Scotland are not.

4.81. The scheme was introduced in 2005 with the BETTA changes, and was designed to compensate Smaller Generators in Scotland for the Embedded Benefits related to transmission *residual* charges their counterparts in England and Wales received (for the Transmission Demand Residual and Transmission Generation Residual charges).¹²²

¹²² BETTA stands for British Electricity and Transmission Arrangements, introduced in 2005 which were new arrangements for electricity trading in GB. Further information can be found at https://www.ofgem.gov.uk/sites/default/files/docs/2005/02/9549-2605.pdf The decision to implement a discount can be found at https://www.ofgem.gov.uk/sites/default/files/docs/2005/02/9549-2605.pdf The decision to implement a discount can be found at https://www.ofgem.gov.uk/ofgem-publications/54716/9798-5905.pdf

4.82. The Smaller Generator Discount was extended until 2021 whilst the TCR was considering the related issues. We consider that the reforms we are proposing will mean the distortions that the Smaller Generator Discount is designed to compensate for (the transmission *residual* charges) will be removed.¹²³

4.83. There is a distortion which might remain (subject to the outcome of the second Balancing Services Charges Taskforce) between Smaller Distributed Generators connected to the 132KV network in Scotland compared to England and Wales. This is because those in Scotland will remain liable for balancing services charges but those in England and Wales will continue not to be. Whilst implementing full reform would have removed this distortion between all domestic generators, under partial reform it will remain at least until the further work on balancing services charges has been undertaken and any changes implemented.

4.84. We consider that the taskforce is best placed to consider the reform of balancing services charges. We expect the outcome of the taskforce to address this remaining distortion. (For the avoidance of doubt, the Small Generator Discount was introduced to compensate for differences in the charging methodologies for transmission *residual* charges only, and was not designed to compensate for any differences in balancing services charges.)

Final decision and next steps

4.85. We consulted on full or partial reform of Embedded Benefits with a preferred option of full reform. We also said that we would take the findings of the first Balancing Services Charges Taskforce into account.

4.86. We considered three remaining embedded benefits and potential reforms through the SCR:

¹²³ Both the Transmission Demand Residual and Transmission Generation Residual for which the Small Generator Discount was set up to provide compensation would no longer hold any value as Embedded Benefits and therefore the scheme should no longer continue to provide a discount.

- Embedded Benefit 1. Set the Transmission Generation Residual to zero. (subject to compliance with EU regulation 838/2010)¹²⁴
- Embedded Benefit 2. Smaller Distributed Generators would not be able to offset suppliers' liability for balancing services charges (and get paid for doing so). This leads to the same gross metering of a supplier's customer demand now in place for the Transmission Demand Residual following our 2017 decision on Embedded Benefits (CMP264/5)
- Embedded Benefit 3. Smaller Distributed Generators would be liable to pay balancing services charges

4.87. Full reform would include making changes to Embedded Benefits 1, 2 and 3, whereas partial reform includes making changes to Embedded Benefits 1 and 2. The conclusions of the taskforce that balancing services charges are cost-recovery charges has informed the change from our preferred option of full reform to making a final decision of partial reform. Currently balancing services charges are recovered from both generation and demand consumers. However, as a cost-recovery charge the reasoned thinking we set out in the working paper, published in November 2017, suggests cost recovery charges should be levied on final demand consumers only.

4.88. As we have agreed that balancing services charges should be treated as cost recovery charges we think, to be consistent in our approach to charging, further consideration should be given to them. Hence our decision to launch a second Balancing Services Charges Taskforce to apply the principles of the TCR to balancing services charges.

¹²⁴ The EU cap and floor refer to European regulation 838/2010 which states that 'Annual average transmission charges paid by producers in each Member State shall be within the ranges set out.....', for which Ireland, Great Britain and Northern Ireland is the range from 0 to 2.50 EUR/MWh. In Great Britain, 'producers' are the larger generators - transmission-connected and larger distribution-connected generators (above 100 MW) - but excludes Smaller Distribution Generators (which are currently treated as negative demand for the purposes of transmission charging).

4.89. This means that the aims of full reform - a reduction in harmful distortions across the three Embedded Benefits we identified as needing reform - is still the final expected objective, but that this will be reached through a three-step process:

- The implementation of partial reform in 2021, to deliver the benefits to consumers by removing the two Embedded Benefits (the Transmission Generation Residual which will be set to zero (subject to compliance with EU Regulation 838/2010), and the offsetting of suppliers' balancing services charges by reducing the Suppliers net imports at the Grid Supply Point) which cause harmful distortions.
- The launch of a second taskforce to consider the application of the TCR principles to balancing services charges (as part of which), consideration will be given to the third Embedded Benefit, the exemption of Smaller Distributed Generators from balancing services charges,
- The second taskforce's work and resulting modifications should delivery reforms to balancing services charges. We expect that this will include addressing the third Embedded Benefit.

4.90. Whilst this decision leaves in place one of the three identified distortions, we expect this to be short term and that the taskforce will determine an implementation time for appropriate changes which balances the interests of all market participants. Further to this, we do not think it is proportionate to implement full reform, which would introduce new charges with significant implementation requirements, and the potential for volatility, while the taskforce undertakes its work. There is a real possibility that any changes made through this SCR would be short term, (subject, of course, to the outcome of the second taskforce itself). It is possible that the taskforce's findings may be implemented, at the same time as the TCR reforms and, if not, are expected to be shortly thereafter, taking the best interests of all market participants into account.

4.91. Our principles-based assessment, which reflects all of the evidence we have been provided with, and supporting wider systems analysis work have led us to decide to implement partial Embedded Benefit reform from April 2021. Our wider systems analysis

suggests there will be consumer savings of between £3.3 and 4.1bn (NVP).¹²⁵ We published a letter in May 2019 explaining the reasons for removing 2020 from the implementation options we consulted on and included the statement `...we consulted on reform of the Embedded Benefits arrangements coming into effect in April 2020 or April 2021. We are now ruling out making these changes in April 2020 and our current preferred implementation date for Embedded Benefits reforms is April 2021'.¹²⁶

4.92. There is further explanation regarding implementation times in Chapter 6, Implementation timing.

4.93. To recap, partial reform includes the first two changes outlined in our 'minded to' decision, which lead to:

- setting the Transmission Generation Residual to zero, subject to maintaining compliance with EU Regulation 838/2010;¹²⁷ and
- charging suppliers' balancing services charges using gross demand measured at the Grid Supply Point, having the effect of removing the Embedded Benefit that enables the offsetting of Suppliers' net power imports and reduction of liability for balancing services charges. This will remove payments from Suppliers to Smaller Distributed Generators for this service;

but excludes:

• requiring Smaller Distributed Generation to pay balancing services charges.

¹²⁵ See Chapter 5, Quantifying the benefits

¹²⁶ <u>https://www.ofgem.gov.uk/system/files/docs/2019/05/may_charging_open_letter_final_21-may.pdf</u>

¹²⁷ The EU cap and floor refer to European regulation 838/2010 which states that 'Annual average transmission charges paid by producers in each Member State shall be within the ranges set out....', for which Ireland, Great Britain and Northern Ireland is the range from 0 to 2.50 EUR/MWh. In Great Britain, 'producers' are the larger generators - transmission-connected and larger distribution-connected generators (above 100 MW) - but excludes Smaller Distribution Generators (which are currently treated as negative demand for the purposes of transmission charging).

4.94. We do not think that there is any reason we should not implement reforms to the transmission Generation Residual and Embedded Benefit 2, as described earlier, whilst the taskforce undertakes its work. This Embedded Benefit is directly impacting consumer bills and making this change will deliver significant consumer savings. Although this Embedded Benefit it might also be addressed through the taskforce findings, The change from measuring gross to net imports at the Grid Supply Point is a straightforward change which we think is in the best interests of consumers and is unlikely to be altered by the outcome of the second taskforce.

4.95. Implementation of the third Embedded Benefit, as described above, would be more complex and because it might be in place for only a short time, it could be disruptive and lead to volatility of charges. We expect that the second taskforce, using the TCR principles, to result in a solution that applies to, and levels the playing field across all generation and considers the best interests of all market participants. If the taskforce conclusions do not do this then we will need to consider what other options are available for us to address Embedded Benefit 3, which we still consider to be a distortion which should be addressed. summarises the changes which will be made and when they will be implemented.

Embedded Benefit	Description	Estimated Size (2020/21)	Impact on Smaller Distributed Generation	Impact on on-site generation
Transmission Demand Residual	Smaller Distributed Generation can receive payments from suppliers and the ESO. On-site generators can receive the same payments when exporting and save demand users the same charges	This will have been phased out by 2020.	Phased out between 2018 and 2020 (Previous code decision - CMP 264/265).	Phased out for exporting on-site generation by CMP 264/265. Remainder addressed by proposed reform of Transmission and Distribution residual charges in TCR.
Transmission Generation Residual	Smaller Distributed Generation does not pay or receive the generation residual.	£279m per year cost to consumers.	Addressed by TCR decision to set the TGR to zero, subject to compliance with	Addressed by TCR decision, to set the TGR to zero which will be implemented in 2021.

Table 11 Summary of changes to be implemented to 'non-locational' Embedded Benefits

	Neither does on-site		838/2010, which will be	
	generation. Larger		implemented in 2021	
	generation receives a			
	credit for this charge			
Balancing	By reducing a supplier's	£109m per	Addressed by TCR	Addressed by TCR
services	net demand, Smaller	year additional	decision, to set	decision, to set balancing
charges:	Distributed Generation	to consumers.	balancing services	services charges based on
payments	receive payments for		charges on gross	gross imports at the Grid
from	reducing balancing		imports at the Grid	Supply Point, which will
suppliers	services charges for		Supply Point, which will	be implemented in 2021
	suppliers.		be implemented in	for exporting on-site
	On-site generators		2021.	generation.
	receive the same			Non-exporting on-site
	payments when			generation will be
	exporting and save			addressed in future if
	demand users the same			balancing services
	charges.			charges are levied on a
				similar basis to
				Transmission and
				Distribution residual
				charges. ¹²⁸
Balancing	Smaller Distributed	£100 to £150m	This distortion will be	This distortion will be
services	Generation and	per year	addressed by the	addressed by a second
charges:	exporting on-site	additional cost	second Balancing	Balancing Services
avoided	generation currently	to consumers.	Services Charges	Charges Taskforce which
charges	does not pay generation		Taskforce which will	will consider who should
	balancing services		consider who should	pay and the design of the
	charges		pay and the design of	charge.
			the charge.	

4.96. The second Balancing Services Charges Taskforce will determine how the TCR principles of:

- reducing harmful distortions,
- fairness, and

¹²⁸ If balancing services charges were levied on final demand on the same basis as the proposed Transmission Generation and Demand Residual charges as the conclusion of the Balancing Services Charges Taskforce would suggest, then the current balancing services charges benefits to on-site generation would be removed. • proportionality and practical considerations

should apply to balancing services charges. There is further information regarding in the open letter launching the second Balancing Services Charges Taskforce published alongside this document.

5. Quantifying the benefits

Chapter summary

This section provides an overview of key quantitative work to support our principlesbased assessment. It sets out key assumptions and results from our modelling work. This analytical work has been carried out consistent with our published Impact Assessment guidance. We have considered feedback from our stakeholders and have undertaken supplementary analysis where appropriate. We recognise that dynamic modelling in a complex system is inherently uncertain and that there are limitations to our approach (and any others).

Introduction to our quantitative work

5.1. As we have undertaken the TCR, our decision-making has primarily been driven by the principles we consulted on at the start of the process, which align with our principal objective and statutory duties. This decision-making has been supported by both quantitative and qualitative analysis. We believe the GB charging regime should be principles-based and predictable with clearly set out rules and objectives. We have carried out modelling to gain insight into the potential savings to both the system and consumers that could be achieved under our proposals and to understand the effect of our proposals.

5.2. This supporting analysis has been carried out in line with our impact assessment guidance, which was published in 2016 and is based on the government's overall approach to appraisal. The guidance sets out our approach to considering the impact of proposals, including monetised aggregate cost-benefit analysis, distributional effects and hard-to-monetise, strategic and sustainability aspects.¹²⁹

¹²⁹<u>https://www.ofgem.gov.uk/publications-and-updates/impact-assessment-guidance</u>

5.3. When we consulted on the decision we were minded to take, we published an independent assessment of some key impacts of our proposed reforms. This work was carried out by expert consultants from Frontier Economics and Lane Clark & Peacock (LCP), and comprised analysis of the distributional and wider systems impacts of our proposed changes to residual charges along with analysis of the wider systems impacts of reform to non-locational Embedded Benefits.¹³⁰

5.4. The distributional impact assessment included a static bill impact analysis setting out the effect of reforms on representative domestic, commercial and industrial consumers.¹³¹ This informed an assessment of potential effects on the behaviour of network users. The wider systems analysis assessed whether the reforms would benefit consumers overall when compared to the existing arrangements. This was based on whole system modelling to 2040. Outputs included the implications for the costs of operating the electricity system and costs to consumers.

5.5. The impacts on network costs are highly location specific, so to model these impacts would require assumptions on the location of newly connecting generation, plant closures or disconnected sites into the future, as well as estimates of the network costs relating to specific sites. We did not think it was proportionate to undertake this exercise for the TCR reforms, which are not designed to send signals to inform network usage. This is consistent with our previous work on Embedded Benefits.¹³² Note that analysis for our Access and Forward-Looking Charges project will include assessment of the impacts of those reforms on network costs.

5.6. A final Impact Assessment has been published with this document.¹³³ This presents the results of the analysis in a format consistent with other Ofgem Impact Assessments. It is a substantially updated version of the draft Impact Assessment of the minded-to TCR policy published on 28 November 2018. The final Impact Assessment includes separate

¹³⁰ <u>https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-minded-decision-and-draft-impact-assessment</u>

¹³¹ Public sector and charitable sector organisations can also match their use with a relevant representative user group.

¹³² https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-consultation-cmp264and-cmp265-minded-decision-and-draft-impact-assessment

¹³³ This supplants the draft Impact Assessment which was published with our minded-to consultation.

summaries of the impact assessments of reforms to residual charges and to Embedded Benefits, along with an overview of the impact of the combined reforms.

5.7. As with any modelling, particularly modelling of a complex nature looking at multiyear impacts, there is a need to use caution when drawing conclusions. The uncertain nature of assumptions such as future demand and commodity prices means that modelling outputs should be treated as indicative. However, this work has provided us with valuable insight as to the anticipated magnitude and direction of impacts and has helped to inform our principles-based assessment.

5.8. We have monetised costs and benefits wherever possible to provide a common metric for evaluation. Where this has not been possible or proportionate, relevant factors have still formed part of our appraisal. An example is that, for the purpose of this quantitative assessment, we assume savings are passed through fully to end consumers. We are aware that this assumption may not fully hold in practice, especially in the near term, and have considered this when making our principles-based assessment.

5.9. The objectives of the TCR SCR are to consider reform for residual charges and nonlocational Embedded Benefits. Delivering an outcome that is fairer and reduces distortions to efficient price signals is clearly in the interests of consumers. This quantitative work supports our assessment of fairness and the level of benefits that can be achieved. As the various aspects of our reform package will have differing impacts on the different generator groups, we have considered the combined impact of the reforms. Overall the package of reforms delivers significant consumer benefits.

5.10. All elements of the TCR SCR are closely linked, involving distortions which affect recovery of residual (or cost recovery) elements of electricity network charges. We signalled these reforms as a package and have assessed them as a package. The first stage of our work assessed the impacts of reform to residual charges, the second stage assessed the impacts of reform to non-locational Embedded Benefits. The same aggregate results would have been produced by assessing our proposed changes to Embedded Benefits first and then reform to residual charges. The benefits attributed to each area of change would however differ as a consequence of the sequencing.

5.11. Our reforms to Embedded Benefits on their own would increase the relative benefit of on-site generation that does not export, creating an incentive for more consumers and organisations to install it, even when it does not lead to any network benefits and is hence not the best outcome for GB consumers as a whole. This is mitigated by the reforms to residual charges, which reduce distortions that favour more generation on-site. Similar distortions may be mitigated by further reform to balancing services charges following the recommendations of the Balancing Services Charges Taskforce. More information on how those recommendations will be taken forward can be found in the letter published alongside this document launching a second Balancing Services Charges Taskforce.

5.12. We are confident that our reforms will help us to deliver decarbonisation of the energy system at lower cost to consumers in the longer term by removing distortions to effective price signals. We have formally assessed the carbon impacts of these changes in line with our published impact assessment guidance and factored these into our assessment of system costs using BEIS appraisal values.¹³⁴ These are valuations of carbon emissions using BEIS published carbon values for UK public policy appraisal; BEIS provide guidance, background and rationale for their use.¹³⁵

Distributional analysis

Approach to distributional analysis

5.13. We carried out distributional analysis to support our assessment by helping us to understand better the impacts of our proposed changes to residual charges and to inform our approach to wider systems modelling. An outline of the initial distributional impacts is provided in the attached report from our consultants, and our detailed assessment of the implications for our decision making is in section 3 of this document.

5.14. The distributional analysis which informed our assessment comprised of two parts:

¹³⁴ https://www.gov.uk/government/collections/carbon-valuation--2#update-to-traded-carbon-values:-2017

 $^{^{135}\} https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gasemissions-for-appraisal$

- Static bill impact analysis this assesses the direct impact of the residual reforms on consumer bills, holding physical behaviour constant. It helps us understand the potential distributional impacts of the reforms by identifying the types of users and types of consumption patterns that are likely to pay less as a result of the changes and those that may be expected to pay more. The effect of the reforms is modelled on a range of different representative domestic, commercial and industrial profiles, informed by data in the public domain and information from network operators. These user groups are designed to represent a reasonable spread of different levels and shapes of consumption, but they are not representative of all consumers.
- Behavioural assessment given the potential impact on network bills for different types
 of users, this is an assessment of the potential for behaviour to be affected in relation
 to how and when customers use the network, choose to invest in on-site generation or
 storage, as well as electric vehicles and heat pumps for domestic users.

5.15. The static analysis for our reform to residual charging illustrates how this form of fixed charges (set by segment volumes) would lead to a moderate reduction in the overall charges paid by domestic households. There would be reductions in charges for high consuming consumers, within a given segment, and increases for low consuming consumers who currently contribute less to residual charges. The distributional analysis showed how outcomes for representative consumers would differ depending on the distribution network area and helped us to understand those parties that would initially pay more and those that would initially pay less from the changes.

5.16. The detailed behavioural assessment explored how these changes in charges might drive changes in consumer behaviour. The main result from this is that the anticipated changes to usage from the reforms are relatively small, with the most significant impacts expected for users with on-site generation. The impacts for investment and dispatch incentives were explored in the wider systems modelling.

5.17. Some respondents have raised a concern that reform of residual charges may result in some consumers disconnecting from the grid. Consumers that are more likely to disconnect are those who have long-term site commitments or ownership, have invested significantly in a specific site, and have access to low cost fuel feedstocks or distributed energy resource, or have access to surplus generation from legacy or co-located activity (see annex 6 of our minded-to consultation). We consider that the overall risk of disconnection is low as the value of being connected to the grid goes beyond providing a source of supply and the cost of replacing the utility achieved from a grid connection is often prohibitively high.

5.18. Comments from stakeholders about our distributional analysis were broadly supportive of our approach. However, there was concern about the presence of generation-only sites and sites with multiple meters, at the extra high voltage level of distribution networks that could significantly affect the distributional analysis for extra high voltage segments. We recognise these concerns, but feel confident that the analysis that was carried out provided adequate insight for our initial principles-based assessment. In the refined analysis published in section 3 and in Annexes 2 and 3 of this document, our consultants have adjusted the EHV dataset to remove sites considered likely to be pure generators, in order to produce more realistic charges. However it has not been possible to accurately identify pure generation sites and possible generation sites have not been removed from the data at other voltage levels (e.g. HV sites).

5.19. Following feedback from stakeholders on our minded-to consultation, we consulted on two refined proposals for non-domestic consumers on 3 September 2019:¹³⁶

- **Refined fixed charge**: where total allowed residual revenue would first be apportioned between voltage levels, on the basis of net volumes, as set out in the November 2018 minded-to consultation; and
- **Hybrid fixed-agreed capacity**: where domestic segment boundaries would be set in terms of agreed capacity levels for users at higher voltages where this data is widely available, and net volume levels at Low Voltage (LV). This is in place of segmenting these users on the basis of the line-loss factor classes (as set out in the minded-to consultation).

¹³⁶ https://www.ofgem.gov.uk/publications-and-updates/future-charging-and-access-programme-consultation-refined-residual-charging-banding-targeted-charging-review

5.20. An illustration of our approach to applying these criteria in the context of an example distribution region was set out in the annex to the September letter. A full outline of illustrative distributional effects for each distribution region is included in Annex 3 of this decision.

5.21. In the September letter, we indicated that the refined band thresholds should be applied on a consistent basis across GB, proposing to set and allocate users to bands on a historic basis and update them periodically in line with price controls.

5.22. Feedback from respondents highlighted the importance of a clear definition of generation and demand for residual charging purposes. Although we proposed a methodology for removing generation sites from the data at extra high voltage level to produce illustrative charges, Chapter 3 sets out that we think the industry-led work groups and later consultation phases of the SCR are best suited to working through the detail of this issue and proposing definitions of generation and demand for the purpose of residual charging.

5.23. Following feedback from stakeholders, we undertook a further detailed assessment of three final leading options for non-domestic banding:

- a refined banded fixed charge, and
- a hybrid fixed-agreed capacity charge.
- 5.24. As a result of this assessment we have decided to implement the further refined fixed charge, whereby:
 - applicable residual charges for each licensed area are allocated to the different voltage levels, according to the total net consumption volumes of all users at each voltage level,
 - users connected at each voltage level are then segmented further into four bands based on percentiles (40th, 70th & 85th) of the user population at each voltage level. The residual charges for each voltage level are allocated to these four customer bands based on total net consumption levels for all consumers in each band, and

 residual charges for each customer band are then divided equally among all users in that band - all users in a band (within each of the 14 distribution areas) pay the same fixed charge.

5.25. Revised distributional analysis reflecting our decision on this further refined fixed charge is set out in Annexes 2 and 3. It shows the static bill impacts of the reformed approach to residual charging. Updated estimates of the charges for each of the final options are provided and compared to updated estimates for the options set out in our minded-to consultation.

5.26. The charges and bill impacts estimated should be considered illustrative and are intended to provide an indication of the expected impacts. The static bill impact analysis uses both data from publicly available sources and data provided by network operators, however many simplifications and assumptions were necessary. The data available does not allow the estimation of the exact charges that could be expected if the options are implemented.

Long-term distributional analysis

5.27. We also commissioned some long-term distributional analysis to explore further how the bill impact of network charging reform for low-consuming domestic consumers who don't have access to on-site generation and storage technology could be affected by changes in potential future scenarios. Noting the future technology mix and distribution is highly uncertain, the technology combinations seen in the scenarios they considered were not found to significantly affect the scale of impacts on these low using consumers. The additional analysis is published alongside this decision.

5.28. Detailed distributional analysis of consumer effects was not carried out for the Embedded Benefits reforms as all consumers will benefit from these reforms and the primary distributional impacts are on different types of generators.

Wider systems modelling

Approach to wider systems modelling

5.29. Wider systems modelling has been used to examine the implications of reforms to demand residual charges at both transmission and distribution level. The level of consumer and/or system benefits under the reforms are compared to current arrangements. The focus of the wider systems modelling is to assess how reforms would change the incentives to benefit from savings in residual charges, and how this affects the system under different potential future scenarios.

5.30. This wider systems analysis provided a quantitative assessment of the impacts of removing the incentives to save on transmission and distribution residual charging, broadly mapping to the reform options we consulted on. This assessment looked at the likely impact on consumer and system costs, energy market dynamics (including wholesale and Capacity Market), generating technologies and their operation (load factors, investment in technologies and fuel mix) up to 2040. The modelling we have undertaken used LCP's EnVision model. EnVision is a fully integrated model of the GB power market which models the build out and closure of generation and the various market interactions.

5.31. Due to the level of uncertainty of future market outcomes, we decided to carry out our analysis using two of National Grid's 2018 Future Energy scenarios (FES).¹³⁷ These scenarios are used by National Grid and the wider industry to consider what different possible visions of the future might look like and the consequences of changes to the system under these different futures. For consistency we retained the same two scenarios from our minded-to decision in our final decision. To recap, the scenarios were one which predicts the least change from the current position (a), and the one representing most change (b), as more fully described below:

- a) Steady Progression (SP), representing a world where there is a slow move to renewables and generation remains mainly centralised; and
- b) Community Renewables (CR), where there is a rapid renewable generation uptake and an increased decentralisation of those assets.

¹³⁷ Information on National Grid's FES scenarios is available here: http://fes.nationalgrid.com/fes-document/.

5.32. We also carried out sensitivity analysis based on lower and higher levels of residual charges, reflecting uncertainty in the overall size of the residual charges over the longer term.

5.33. We then applied these changes to two scenarios for the reform of residual charges, which we can compare to the 'baseline' of the current position (where the existing arrangements remain in place). In the first reform scenario (called 'full reform – incentive completely removed'), these changes are applied to all on-site generation technologies. In the second reform scenario (called 'partial reform – mitigated incentives'), these changes are applied only to on-site generators that can be used to respond to enable triad avoidance, largely gas and diesel reciprocating engines. The latter is consistent with an option (eg net volumetric charging or some ex-post charging options) where baseload generation continues to allow avoidance of residual charges, but on-site generation that is designed to respond for short periods does not.¹³⁸

5.34. The system modelling for the reform scenarios were mapped back to the charging options under consideration. The shortlisted charging options all reduce incentives for on-site thermal generation and solar with onsite storage, and so are consistent with the 'Full Reform' scenario where the incentives for on-site generation are removed completely.¹³⁹

Overview of the results of the wider systems modelling

5.35. Our wider systems modelling indicates a strong long-term case for reform of both residual charges and non-locational Embedded Benefits. A similar modelling framework was used to quantify the aggregated costs and benefits for residual reform and Embedded Benefits, and benefits from these reforms are additive. The numbers quoted are based on modelling work that has been carefully undertaken but outputs are inevitably sensitive to the assumptions used. The key results are:

¹³⁸ See section 5.2 of the Frontier / LCP 'Distributional and wider system impacts of reform to residual charges' report published alongside our minded-to consultation https://www.ofgem.gov.uk/system/files/docs/2018/11/distributional_and_wider_system_impacts_of_ reform_to_residual_charges.pdf

- Our residual reforms are projected to result in £0.5bn to £1.6bn of projected consumer benefits.¹⁴⁰ The system benefits are even larger, ranging from £1.0bn to £3.2bn.¹⁴¹ These include the range of benefits if the overall level of residual charges increases or decreases by 50%.¹⁴²
- The reforms to non-locational Embedded Benefits are projected to bring net consumer benefits to 2040 in the range of £3.3bn to £4.1bn. The projected impacts indicated that there would not be a significant impact on system costs, with the effect ranging from no change to a net cost of £0.3bn.
- The sum of the two elements of reform are £3.8bn to £5.3bn of consumer benefits and £0.8bn to £2.9bn of system benefits. Again, this includes the residual charge sensitivity calculations.

5.36. The sensitivity analysis indicates significant benefit to reform, including under scenarios where the overall amount to be recovered from residual charges is smaller or larger than currently forecast. This provides us with reassurance that this reform would bring benefits even if the allowed revenues were to change significantly in RIIO2 or if changes arising from the Electricity Network Access Project were to increase or decrease the proportion of charges recovered by forward-looking and residual charges.

5.37. An overview of the costs and benefits of the package of TCR reforms is presented in Table 12.

¹⁴⁰ 'Consumer Benefits' here reflects a reduction in Consumer Costs which are the costs faced by consumers via their electricity bills. This includes wholesale energy costs, network charges, renewable subsidies, Capacity Market payments and any other charges passed on by suppliers, such as the triad avoidance payments made to on-site generation.

¹⁴¹ System Costs represent the actual resource cost of running the system. This includes, fuel costs, variable and fixed operational and maintenance costs, capital costs, carbon costs (priced at appraisal value) and the cost to society of any expected energy unserved.

¹⁴² This is the change increasing or decreasing by 50% between 2020 and 2030 remaining flat in real terms thereafter.

Reform	Future	Consumer	System	System
	Energy	benefits	benefits	benefits
	Scenario		(central	(high carbon
			carbon	appraisal
			appraisal	sensitivity)
			value)	
Residual	Steady	0.5	1.0	1.8
Reforms	Progression			
	Community	1.2	3.2	6.1
	Renewables			
	High Residual	1.6	1.0	1.9
	(based on			
	Steady			
	Progression)			
	Low Residual	0.5	0.8	1.3
	(based on			
	Steady			
	Progression)			
Embedded	Steady	3.3	0.0	0.0
Benefits	Progression			
(`partial'	Community	4.1	-0.3	-0.4
BSUoS	Renewables			
reform)				

Table 12 Overview of projected benefits of TCR reforms £bn, NPV 3.5%, 2019-2040

5.38. The impacts on carbon emissions were assessed and monetised, and a separate breakdown of monetised carbon emissions under the different scenarios and sensitivities is included in the Impact Assessment published alongside this document. The combined effect of the reforms is a net reduction in carbon emissions as generation shifts to more efficient CCGT plant and increased interconnection imports.¹⁴³ Note that no carbon emissions are attributed to interconnector imports, and there are some increased carbon

¹⁴³ Combined Cycle Gas Turbine plant
emissions from increased electricity export from GB to other countries, as carbon emissions are reported on a territorial production basis. This partly explains the small increase under the Embedded Benefits reforms, as the modelling indicates a rise in domestic generation at the expense of interconnector imports. This is because interconnectors are exempt from balancing services charges and their competitive advantage is reduced by our reforms.

- 5.39. The wider systems modelling that is set out in our consultants' reports also examines the impact of our proposed changes on the following key aspects:
- the economics of on-site generation,
- changes to the capacity mix,
- Capacity Market clearing prices,
- Loss of Load Expectation (LOLE), and
- wholesale prices.

5.40. The indicated consumer benefits should correspond to a decrease in producer surplus (i.e. a decrease in net revenue for generators), if there are no system costs savings. We have published analysis setting out the main direct impacts of the TCR reforms on different generator groups, indicating how different elements of the TCR affect the various types of generation. It does not take account of second order impacts such as changes in wholesale prices. A high level overview of the findings is available in Figure 8.

Figure 8 Projected overall impacts on generator groups (NPV, £bn to 2040)¹⁴⁴



5.41. Concerns were raised by some stakeholders about several aspects of our approach to the modelling and the assumptions used. These are outlined in the summary of responses published along with this decision. Some of these stakeholder concerns reflect limitations inherent in available modelling techniques and the information that can be used.

5.42. However, some stakeholders highlighted the implications for renewable generators of our reforms to address the remaining non-locational Embedded Benefits, and the impact of the suspension of the Capacity Market on the robustness of our modelling. We have undertaken some additional analytical work to address these points and this is outlined in the following sections.

Capacity Market suspension and our quantitative assessment

5.43. In November 2018, the Capacity Market was suspended. We then modelled a scenario without the Capacity Market in place, to test the sensitivity of our impact

¹⁴⁴ Note that in this chart CM refers to Capacity Market, RO to Renewable Obligation, CfD to Contracts for Difference and FiT to Feed in Tariffs.

assessment to it not being reinstated. The analysis assessed the combined impact of residual reforms with TGR and full BSUoS reform under the Steady Progression FES scenario. The results of the sensitivity modelling showed positive consumer benefits from reforms.¹⁴⁵ They also showed positive system benefits, but lower than in the original modelling.

5.44. We made our consultants' report and backing data available for stakeholders to consider. Respondents generally agreed that this was a prudent exercise, and with the assumptions used. Two respondents expressed clear agreement that our reforms are robust to a no Capacity Market scenario and three stated their disagreement. In our view, the results indicated that benefits of the combined residual and non-locational Embedded Benefits TCR reforms are robust to an energy-only market, in that they would still be expected to deliver significant consumer and system benefits.

5.45. On 24 October 2019, the European Commission announced its decision that the GB Capacity Market scheme is compatible with EU State aid rules. The following day, the Business Secretary, Andrea Leadsom, wrote to the Electricity Systems Operator confirming that the Capacity Market was to be resumed.¹⁴⁶

Reform to non-locational embedded benefits and renewable generation

5.46. In the modelling published with our minded-to consultation, renewable deployment was fixed as an exogenous assumption based on the two FES scenarios following the approach recommended by our independent consultants. They recognised that reform of the remaining non-locational Embedded Benefits would impact revenues of grid connected

 $^{^{145}}$ The results of this sensitivity analysis showed a consumer benefit of £4.8bn in Net Present Value (NPV) over the period to 2040 (at a similar level to our modelling of residual reforms combined with TGR and full BSUoS reform with the Capacity Market in place). Full reform was the basis for the sensitivity due to the timing of when this sensitivity was commissioned, it means that the results are not directly comparable with the headline projections in this decision document.

https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/8 42238/Trigger_Letter_-_NGESO_SIGNED.pdf

generation, and assumed that the Government's Contracts for Difference (CfD) support payments would adjust to maintain renewable deployment in the reform scenarios.

5.47. A number of respondents expressed concerns that renewable generation uptake could be materially affected by the reforms. Particular concern was raised about the compatibility of the build assumptions in our modelling with the renewables subsidy framework.

5.48. Some industry parties commissioned Oxera to carry out analysis on the reforms to remaining non-locational Embedded Benefits.¹⁴⁷ They applied an extreme assumption that, as a result of the reforms, no further onshore wind and solar PV would be built. Analysis by Aurora suggested a more modest though still significant impact that investment in subsidy-free renewables could be set back by 2-5 years following reforms.¹⁴⁸ Oxera argued that it would be reasonable to consider undertaking an additional sensitivity analysis to test the robustness of projected impacts on consumer and system costs from our proposed reforms to Embedded Benefits.

5.49. In recent months, BEIS confirmed that there will be no funding for onshore wind and solar PV in the 2019 CfD funding round. We asked our consultants to consider the potential impact, should this policy continue, on the system and consumer benefits previously estimated. This new sensitivity was modelled against the background of the same FES background scenarios that were used previously. The FES scenarios are not consistent with a policy of subsidy-free onshore wind and solar PV, and the work should be treated as an illustrative sensitivity analysis.¹⁴⁹

¹⁴⁷ Commissioned by Innogy, RES, Scottish Power and Vattenfall. Available here: <u>https://www.oxera.com/wp-content/uploads/2018/01/Ofgem%E2%80%99s-Targeted-Charging-Review-A-review-by-Oxera.pdf.</u>

¹⁴⁸ Aurora's analysis is available here: https://www.auroraer.com/wp-

content/uploads/2019/05/Aurora-TCR-Public-Report-May-2019.pdf.

¹⁴⁹ To ensure internal consistency of the modelled scenarios, the support levels assumed in the counterfactual of our previous analysis for onshore wind and solar are maintained and compared to higher support costs implied as a result of the replacement with offshore wind capacity in the reform scenario. This is inconsistent with the idea that they are subsidy free but is considered appropriate given that our focus is on the incremental impact of the switch from onshore wind and solar PV to more expensive offshore wind.

5.50. Our consultants, Frontier/LCP, tested the benefits case previously presented against a large reduction in onshore wind and solar PV investment of 50% to the levels set out in the FES scenarios. This should not be considered a prediction but rather an illustration of how the benefits case for our reforms changes in response to this assumption.

5.51. It is assumed that the government would maintain the level of renewable outputs assumed in the relevant FES scenario by continuing to support offshore wind.¹⁵⁰ This means that the analysis assesses the impact on system and consumer benefits of replacing currently cheaper onshore wind and solar technologies with more renewables (currently expensive offshore wind technology). As a result, changes in consumer and system costs relative to our previous analysis are linked closely to the differences in (the assumed) cost between onshore wind and solar PV compared to offshore wind.

5.52. The results of our modelling show that, in a scenario with subsidy-free onshore wind and solar PV, consumer benefits are lower but still very large, ranging from £1.9bn -£3.5bn. The increase in projected system costs to £1.0bn - £4.1bn reflects the assumption that support payments are used to incentivise replacement of onshore wind and solar PV with more expensive offshore wind.¹⁵¹ The range of benefits quoted are for the Embedded Benefit full reform scenario, using Steady progression and Community Renewables FES.

5.53. The system and consumer cost impacts are summarised in the table below. The results from the previous analysis are shown for comparison. These additional outputs have been factored in to our principle-based assessment and decision. A full breakdown is available in the consultants' report which was published with our September 2019 consultation.¹⁵²

¹⁵⁰ Carbon targets are legally binding and government has recently legislated to achieve net zero carbon by 2050: https://researchbriefings.parliament.uk/ResearchBriefing/Summary/CBP-8590. ¹⁵¹ This analysis does also not take account that the hurdle rate associated with an unsupported technology is typically higher than for the same project under the CfD regime. This in turn increases the levelised (per unit lifetime cost of ownership) for these technologies and if taken into account would reduce the difference in levelised cost between unsupported onshore wind and solar PV and CfD supported offshore wind.

¹⁵² <u>https://www.ofgem.gov.uk/publications-and-updates/future-charging-and-access-programme-consultation-refined-residual-charging-banding-targeted-charging-review</u>

Future Energy Scenario	Consumer benefits	System benefits (central carbon appraisal value)	<i>Of which, value of carbon emissions</i>
Steady Progression partial BSUoS	4.5	0.0	-0.2
reform – Central case			
Community Renewables partial	6.0	-0.3	-0.4
BSUoS reform – Central case			
Steady Progression partial BSUoS	3.5	-1.0	-0.4
reform – Renewable sensitivity			
Community Renewables partial	1.9	-4.5	-1.1
BSUoS reform – Renewable			
sensitivity			

 Table 13 Renewable sensitivities & total benefits (£bn, 3.5% NPV)

5.54. About 20 stakeholders commented on this additional renewable sensitivity analysis. There were mixed views on the assumed decline in solar and onshore wind build, some arguing that 50% is too high and others that it is too low. More respondents suggested that a 50% reduction is too low, meaning the impact of these reforms is not fully captured and our reforms would affect the ability to meet decarbonisation targets. A fuller breakdown of the stakeholder feedback is published alongside this document.

5.55. We believe that this sensitivity analysis using an illustrative 50% reduction assumption indicates that our benefits case is robust to a reduction in onshore wind and solar PV. The implications for decarbonisation are set out in the following paragraphs.

Our support for decarbonisation

5.56. We see this decision as helping decarbonise the energy system at lower costs to consumers, in line with our principal objective and statutory duties. The TCR package of reforms is expected to reduce both carbon emissions and costs to consumers, and hence support decarbonisation at lower cost to consumers. The projected effects of the reforms on GB carbon emissions are set out in the chart below. These reductions arise since our

modelling indicates an increase in generation from more efficient CCGT plant and increased interconnection imports (for which no CO2 emissions are attributed).



Figure 9 Projected CO2 emissions in millions of tonnes, with alternative FES scenario

5.57. Some stakeholders expressed concern that projected reductions in distribution connected generation under our Embedded Benefits reforms will affect decarbonisation. Figure 9 above illustrates the anticipated reductions in carbon emissions as a result of the TCR reforms. In any case, there is no justification to support particular types of generation through inefficient price signals. We have assumed that the government continues to take the necessary action to ensure that carbon targets are met.

5.58. We agree that regulation (to the extent practicable) should be predictable in order to provide a stable regulatory framework for the energy sector, helping to keep costs low for consumers. In this regard, we have been clear that our network charging framework should evolve over time as the system changes. Reforms can be initiated both through Ofgem reviews and industry open governance. Delivering good long-term outcomes for consumers is best achieved by allowing efficient price signals to drive behavioural response so that the system works well, and ensuring residual charges do not create harmful distortions to these signals and are fair.

6. Implementation Timing

Chapter summary

This chapter outlines the arrangements for the implementation of our reforms to residual charges and `non-locational' Embedded Benefits. It addresses the issues raised by stakeholders in response to our minded-to consultation and explains how we have reached our final decision.

We have decided to implement residual reforms in 2021 for transmission charges, and 2022 for distribution charges, and reform to the remaining non-locational Embedded Benefits in 2021.

Background

6.1. We have approached our assessment of the implementation arrangements of the reforms in a similar way to the reforms themselves, using the three TCR principles to consider how the timing and method of implementation contribute to:

- reducing harmful distortions,
- fairness, and
- proportionality and practical considerations.

6.2. Our assessment of the options for implementing these reforms takes into account the additional information provided through the consultation responses and stakeholder feedback when making this final decision. We have also taken into account the wider systems analysis, which provides information about the potential consumer and system benefits and costs of different implementation timings and scenarios. These have been carried out for residual charges and Embedded Benefits.

The minded-to position

6.3. In our minded-to consultation, published in November 2018, we consulted on two leading options for implementation of changes to residual charges:

- full implementation in April 2021, and
- phased implementation from April 2021 with changes fully implemented by April 2023.

6.4. On 21 May 2019, we issued an open letter updating stakeholders which indicated that implementation in 2023 would also be considered alongside implementation in 2021 and phasing of the changes between 2021 and 2023.¹⁵³

6.5. For the remaining Embedded Benefits, the minded-to consultation presented two leading options for implementation of reforms – April 2020 or April 2021. We also considered phasing these reforms between 2021 and 2023. In the open letter in May 2019 we said:

"We have taken the decision to remove the option of implementing the other embedded benefits element of reform in April 2020, to allow time to consult on further analysis... Our current preferred option is to implement either partial or full reform in April 2021, subject to consulting on this further analysis."¹⁵⁴

6.6. We removed the option of implementation in 2020 to allow for the additional time taken for modelling sensitivities to be run, which considered the interactions between our reforms and the Capacity Market, given its unexpected suspension. Whilst the Capacity Market has now been reinstated, we considered it sensible to test out our reforms against this unexpected scenario to ensure that potential consumer benefits remained robust in the event that the Capacity Market was not reinstated. This meant that under the TCR principle of proportionality and practical considerations, it would not be possible to implement Embedded Benefit reforms in 2020 because there would not be enough time to follow standard industry processes before the implementation date. As a result, April 2021 became the preferred option.

Summary of responses to the minded-to consultation

 ¹⁵³ https://www.ofgem.gov.uk/system/files/docs/2019/05/may_charging_open_letter_final_21may.pdf
 ¹⁵⁴ Ibid.

Residual Charges

6.7. Most respondents to the consultation preferred later implementation options. This reflected concerns around significant changes to charges, the practical challenges of implementing reforms, and a desire to link the changes to the work being undertaken through the Access and forward-looking charges SCR.¹⁵⁵

6.8. A number of DNOs highlighted the challenges of implementing our reforms to distribution residual charges in 2021. A number of respondents highlighted similar concerns, suggesting that derogating against the 15 months' notice period for distribution charges could more than offset the benefits derived from implementing in 2021. This was partly due to the time it would take to implement the changes, and partly because suppliers noted they have fixed contracts with their customers reaching out to 2022.

6.9. Stakeholder responses to the minded-to consultation suggested that transitional arrangements (implementing these changes over more than one year) could result in complex charging arrangements, citing the fundamental change to the charging structures that the residual reforms could create. However, a number of stakeholders supported earlier implementation of transmission residual reform in 2021, suggesting this would quickly remove the largest distortion, and then changes to distribution residual charges could be implemented in 2022 in line with standard industry timelines.

6.10. A number of respondents to our September 2019 open letter also indicated their preference for later implementation options.

6.11. In our assessment, we considered that a long transition, with changes only fully implemented by 2023, could result in a significant loss of consumer benefits, and that incremental changes over more than one year would also increase complexity for consumers. However, phased implementation could soften the distributional impacts of the reforms and help with predictability of charges for end consumers. The option to reform transmission residual charges in 2021 and distribution residual charges in 2022 falls within

¹⁵⁵ <u>https://www.ofgem.gov.uk/publications-and-updates/access-and-forward-looking-charges-</u> significant-code-review-summer-2019-working-paper

the range of implementation timeframes we consulted on. As such, we have also considered the merits of this option alongside our three leading implementation options and have also considered implementation across both transmission and distribution in 2022.

6.12. Some respondents to the minded-to consultation thought we should align implementation of residual reform with reforms introduced through the Access and forward-looking charging SCR, in April 2023. They suggested such alignment would provide greater transparency and forecastability of charges for market participants, and provide a holistic implementation plan which coincides with new RIIO price controls. There were suggestions that the reforms to residual charges would dampen useful signals for some users on the network, if implemented before improved signals are introduced through the Access and forward-looking charging reforms. Some stakeholders suggested residual reform would have a detrimental effect on revenue streams for flexibility providers, and that coordination with Access reforms would avoid stalling the emergence of flexibility providers.

6.13. While we recognise aligning with the reforms to Access and forward-looking charges would allow market participants more time to adjust to changes and see the combined impact of both sets of reform, it would lead to the slowest removal of harmful distortions, and reduce benefits for consumers overall. These reforms have been signalled for some time, since 2016, and we expect that prudent investors and market participants will be aware of these changes and will have factored them into their forward planning.

Embedded Benefits

6.14. Those industry participants who gave a preference said we should consider later implementation periods for reforms to Embedded Benefits. A number of participants also argued that reform to Embedded Benefits should be delayed until 2023.

6.15. Consumer groups, on the other hand, advocated faster implementation timings to ensure savings from reforms were passed through to consumers as soon as possible. A number of generators, especially those who held CfD contracts, advocated grandfathering or long transitional arrangements, arguing that our sustainability duty meant we should protect renewable generators from adverse impacts of charging reform.

Our Decision

Residual Charges

Implementation	Change	Fairness	Reducing	Proportionality and practical considerations		
Options	in		harmful			
	consumer		distortions	Practical	Proportionality	Proportionality
	cost			considerations	 disruption to 	– short term
	(from			and delivery	market	distributional
	2021)			risk	participants	impacts for
					(excluding	consumers
					consumers)	
2021	0	Overall	Harmful	New residual	Quickest	Option results in
		benefits	distortions	charging	reduction in	significant
		implemented	quickly reduced	structures	inefficient	distributional
		quickly and	but the rapid	implemented	investment.	impacts to
		simply.	implementation	two years ahead		consumers, with
		Significant	may limit	of Access and		a reduced notice
		changes in a	immediate	forward-looking		period.
		short time	realisation of	charging		
		period.	benefits as	reforms that		
		Reduced	there may be	could result in		
		charging	insufficient time	duplication of		
		predictability	to pass benefits	industry		
		compared to	on to	processes.		
		other	consumers.	Tight timeline to		
		options.		deliver		
				distribution		
				charging		
				changes.		
Phased between	+£60m	Consumer	Harmful	New residual	Generators and	Distributional
2021 to 2023		benefits	distortion is	charging	investors have a	impacts
		phased over	removed	structures	three-year	softened by
		time.	moderately	implemented	period to adjust	phasing but
		Changes are	quickly.	incrementally	behaviour with	longer delay for
		implemented		over three years	sight of changes	full consumer
		incrementally		ahead of access	to access	benefits to
		which		and forward-	reform. There	materialise.
		increases		looking charging	may be some	
		complexity		reforms with	inefficient	
		for users.		some	investment.	
				inefficiency of		
				industry		
				changes.		
				Provides limited		
				contingency for		
				industry		

				modification process for distribution charging changes.		
2021 for Transmission and 2022 for Distribution	+£25m	Benefits phased in over two years, moderately quickly. Changes are introduced under standard industry timelines, with standard notice periods, with strong predictability.	Biggest distortions from transmission residual charges are removed quickly, and distribution residual charging changes following a year later.	Results in residual charging structures coming in two years ahead of Access and forward-looking charging reforms, with some potential inefficiency of industry changes. Modifications progress under standard timetables.	Some additional time for generators and investors to adjust behaviour, with expected loss of Triad revenues from 2021.	Distributional impact softened by phasing. Largest benefit realised in 2021, but with some delay to realising full benefits.
2022	+£75m	Benefits implemented in a single year, yet there is no firm basis for selecting 2022. Introducing all changes in a given year is simpler for users to understand.	Distortions removed moderately quickly, but biggest distortion (from transmission residual charges) remains in place for an additional year.	Results in residual charging structures coming in one year ahead of reform of Access and forward- looking charging with some potential inefficiency of industry changes.	Additional time for generators and investors to adjust behaviour.	Users who gain from reforms face long delay before implementation.
2023	+£140m	Significant delay to benefits. Introducing all changes in a given year is simpler for users to understand.	Slowest removal of harmful distortion, although modelled system benefits are robust to delay in implementation.	Ample time for implementation with the same timescale as Access and forward-looking charging reform.	More likely that investors invest in inefficient technology, but many stakeholders would prefer TCR and Access and forward- looking charges SCRs are	Softens distributional impact on low users consumers, but those gaining from these reforms face long delay before implementation.

		implemented together.	

6.16.

6.17. Table 14 outlines our quantitative and qualitative assessment of the different implementation options, focusing on our principles of reducing harmful distortions, fairness and proportionality and practical considerations, including potential impacts for consumers and market participants.

6.18. We have decided that reform to transmission residual charges should be implemented in 2021 and distribution residual charges in 2022. We consider this strikes an appropriate balance between addressing the largest distortions quickly to deliver consumer benefits, while softening the distributional impacts on consumers and maintaining strong predictability in the charging regime (by following the standard industry timelines for implementation). This approach also provides high levels of confidence for timely delivery.

Embedded Benefits

6.19. In a similar way to assessing the implementation of the residual charges reform, we have assessed the timing for implementation of Embedded Benefit reform against the TCR principles. We considered the implementation options to ensure we took into account issues such as better alignment with the Access and forward-looking charges review. The results of this assessment are shown in Table 15.

6.20. We think there has been sufficient time for both investors and market participants to anticipate these potential changes. We consider that the potential benefit to consumers from these changes being made earlier outweighs the reasons for delaying the implementation of these reforms. Having considered all responses and evidence submitted, we remain of the view that the preferred implementation option is April 2021, and will implement partial reform of Embedded Benefits in April 2021.

6.21. We realise that there is still some discrepancy remaining between larger and smaller generation, with respect to the former being liable for balancing services charges and the latter not. As a result, we are launching a second Balancing Services Charges Taskforce which we expect to provide conclusions regarding necessary changes to balancing services charges and implementation timing which are in the best interests of all market participants.

Implementation	Change in	Fairness	Reducing harmful	Proportionality and practical considerations			
Options	consumer		distortions				
	cost (from			Practical considerations and	Proportionality – disruption to	Proportionality – short	
	2021)			delivery risk	market participants (excluding	term distributional	
					consumers)	impacts for consumers	
2021	0	Overall benefits implemented	Harmful distortions quickly	New residual charging structures	Quickest reduction in inefficient	Option results in	
		quickly and simply.	reduced but the rapid	implemented two years ahead of	investment.	significant distributional	
		Significant changes in a short	implementation may limit	Access and forward-looking charging		impacts to consumers,	
		time period. Reduced charging	immediate realisation of	reforms that could result in duplication		with a reduced notice	
		predictability compared to other	benefits as there may be	of industry processes.		period.	
		options.	insufficient time to pass	Tight timeline to deliver distribution			
			benefits on to consumers.	charging changes.			
Phased between	+£60m	Consumer benefits phased over	Harmful distortion is	New residual charging structures	Generators and investors have a	Distributional impacts	
2021 to 2023		time.	removed moderately	implemented incrementally over three	three-year period to adjust	softened by phasing but	
		Changes are implemented	quickly.	years ahead of access and forward-	behaviour with sight of changes to	longer delay for full	
		incrementally which increases		looking charging reforms with some	access reform. There may be	consumer benefits to	
		complexity for users.		inefficiency of industry changes.	some inefficient investment.	materialise.	
				Provides limited contingency for			
				industry modification process for			
				distribution charging changes.			
2021 for	+£25m	Benefits phased in over two	Biggest distortions from	Results in residual charging structures	Some additional time for	Distributional impact	
Transmission and		years, moderately quickly.	transmission residual	coming in two years ahead of Access	generators and investors to adjust	softened by phasing.	
2022 for Distribution		Changes are introduced under	charges are removed	and forward-looking charging reforms,	behaviour, with expected loss of	Largest benefit realised in	
		standard industry timelines,	quickly, and distribution	with some potential inefficiency of	Triad revenues from 2021.	2021, but with some	
		with standard notice periods,	residual charging changes	industry changes.		delay to realising full	
		with strong predictability.	following a year later.	Modifications progress under standard		benefits.	
				timetables.			

Table 14 Assessment of residual reform implementation options

+£75m	Benefits implemented in a	Distortions removed	Results in residual charging structures	Additional time for generators and	Users who gain from
	single year, yet there is no firm	moderately quickly, but	coming in one year ahead of reform of	investors to adjust behaviour.	reforms face long delay
	basis for selecting 2022.	biggest distortion (from	Access and forward-looking charging		before implementation.
	Introducing all changes in a	transmission residual	with some potential inefficiency of		
	given year is simpler for users	charges) remains in place	industry changes.		
	to understand.	for an additional year.			
+£140m	Significant delay to benefits.	Slowest removal of	Ample time for implementation with	More likely that investors invest in	Softens distributional
	Introducing all changes in a	harmful distortion,	the same timescale as Access and	inefficient technology, but many	impact on low users
	given year is simpler for users	although modelled system	forward-looking charging reform.	stakeholders would prefer TCR and	consumers, but those
	to understand.	benefits are robust to		Access and forward-looking	gaining from these
		delay in implementation.		charges SCRs are implemented	reforms face long delay
				together.	before implementation.
	+£75m +£140m	+£75m Benefits implemented in a single year, yet there is no firm basis for selecting 2022. Introducing all changes in a given year is simpler for users to understand. +£140m Significant delay to benefits. Introducing all changes in a given year is simpler for users to understand.	+£75mBenefits implemented in a single year, yet there is no firm basis for selecting 2022. Introducing all changes in a 	+£75mBenefits implemented in a single year, yet there is no firm basis for selecting 2022. Introducing all changes in a given year is simpler for users to understand.Distortions removed moderately quickly, but biggest distortion (from charges) remains in place for an additional year.Results in residual charging structures coming in one year ahead of reform of Access and forward-looking charging with some potential inefficiency of industry changes.+£140mSignificant delay to benefits. Introducing all changes in a given year is simpler for users to understand.Slowest removal of harmful distortion, although modelled system benefits are robust to delay in implementation.Ample time for implementation with the same timescale as Access and forward-looking charging reform.	+£75mBenefits implemented in a single year, yet there is no firm basis for selecting 2022. Introducing all changes in a given year is simpler for users to understand.Distortions removed moderately quickly, but biggest distortion (from transmission residual charges) remains in place for an additional year.Results in residual charging structures coming in one year ahead of reform of Access and forward-looking charging with some potential inefficiency of industry changes.Additional time for generators and investors to adjust behaviour.+£140mSignificant delay to benefits. Introducing all changes in a given year is simpler for users to understand.Slowest removal of harmful distortion, although modelled system benefits are robust to delay in implementation.Ample time for implementation with the same timescale as Access and forward-looking charging reform.More likely that investors invest in inefficient technology, but many stakeholders would prefer TCR and Access and forward-looking charges SCRs are implemented together.

Options	Change in consumer	Fairness	Reducing harmful distortions	Proportionality and practical considerations				
	cost (from 2020)	Fairness applies to demand only		Practical considerations and delivery risk	Proportionality: disruption to market participants (excluding consumers)	Proportionality: Short term Distributional impact for consumers		
A - 2021	+£500m	N/A	Harmful distortions removed quickly.	Delivery in 2021 allows ample time for implementation.	Quickest reduction in inefficient investment, but there has been significant notice of change.	Consumers see reduced bills quickly, although dependant on supplier pass-through.		
B - 2021- 2023 phased	+£1bn	N/A	Significant reduction in benefits case although harmful distortion is eventually reduced.	Delivery in 2021 allows ample time for implementation. Phasing may add complexity to process of implementation.	Additional time for generators and investors to adjust behaviour but this has been signalled since at least 2016.	Longer delay for full benefits to materialise.		
E – 2023	+£1.5bn	N/A	Slowest removal of harmful distortions with significant reduction in the benefits case.	Ample time for implementation.	More likely that investors invest in inefficient technology. But many would prefer TCR and Access and forward-looking charging reforms to be implemented together.	Long delay for full benefits to materialise and reduced benefit which is not proportional to the long- signalled change.		

Table 15 Assessment of 'non-locational' Embedded Benefit reform implementation options

7. Conclusion and next steps

Chapter summary

This section provides a high level summary of the conclusions of the TCR (in respect of residual charges and non-locational Embedded Benefits), the changes to our approach since the minded-to consultation and the next steps to be taken.

Summary of the reforms to be implemented

Residual Charges

- 7.1. Our final decision on Residual Charges reform is:
- Fixed charges: to be levied on final demand consumers only and will be implemented for transmission charges in 2021 and for distribution charges in 2022. This includes:
 - for transmission charges, charges for non-domestic consumers will use a series of fixed charging bands set for all of GB.
 - for distribution charges, domestic consumers will pay a single residual charge set for each licensed area, and non-domestic consumers will be charged on the basis of a set of fixed charging bands also set for each distribution area.
 - the series of fixed charging bands will be published at a national level and shall be set for each Distribution Network Area.
 - transmission-connected consumers shall pay transmission residual charges, and distribution-connected consumers shall pay both transmission and distribution residual charges.

 reviewing and revising (as appropriate) of these charging bands and their boundaries so that the outcome of such reviews can be implemented alongside the commencement of each new electricity transmission price control.

Embedded Benefits

- 7.2. Our final decision on 'non-locational' Embedded Benefits is:
- "Partial" reform: to be implemented in 2021. This comprises:
 - setting the Transmission Generation Residual to zero (subject to compliance with the €0 €2.50/MWh range set out in EU Regulation 838/2019),¹⁵⁶ and
 - charging balancing services charges for demand on the basis of gross demand at the Grid Supply Point so that suppliers cannot reduce their liability for balancing services charges by contracting with Smaller Distributed Generators (and exporting on-site generation).

• A second Balancing Services Charges Taskforce is being launched to determine:

- who should pay balancing services charges; and
- how balancing services charges should be recovered.

7.3. The second Balancing Services Charges Taskforce will build on the work of the first taskforce. The latter concluded that "It is not feasible to charge any of the components of

¹⁵⁶ The EU cap and floor refers to European regulation 838/2010 which states that 'Annual average transmission charges paid by producers in each Member State shall be within the ranges set out....', for which Ireland, Great Britain and Northern Ireland is the range from 0 to 2.50 EUR/MWh. In Great Britain, 'producers' are the larger generators - transmission-connected and larger distribution-connected generators (above 100 MW) - but excludes Smaller Distribution Generators (which are currently treated as negative demand for the purposes of transmission charging).

BSUoS in a more cost-reflective and forward-looking manner that would effectively influence user behaviour that would help the system and/or lower costs to customers. Therefore, the costs included within BSUoS should all be treated on a cost-recovery basis".¹⁵⁷

7.4. The second taskforce will use the aims and principles applied during the TCR to make recommendations for future liability, and design of balancing services charges.

7.5. The conclusions of the second taskforce must be submitted to Ofgem by the end of June 2020 for our consideration. Ofgem will then make a decision on whether to accept the recommendations and the next steps to be undertaken.

Changes since the minded-to consultation

Residual Charges

7.6. Our minded-to consultation proposed that different groups of non-domestic consumers would pay different fixed residual charges, depending on the voltage level they are connected to and their Line Loss Factor Class. For domestic consumers, we proposed that consumers with Economy 7 meters should pay higher residual charges than those without these meters.

7.7. Following consideration of responses to the minded-to consultation, and our June and September consultations we have decided to implement banding by agreed capacity, where these agreements are in place, or by net volumes where they are not, for nondomestic consumers. For domestic consumers we have decided to implement only one fixed charge for domestic users, rather than differentiating between those with Economy 7 meters and those without.

7.8. We have taken a great deal of care in reaching this decision, particularly considering vulnerable consumers and the breadth of consumers who are present in some of the user groups, such as small business and commercial users who are connected to the low voltage

¹⁵⁷ <u>http://chargingfutures.com/media/1348/balancing-services-charges-task-force-final-report.pdf</u>

network. We propose that the banding and the charging boundaries should be reviewed so that the outcome of such reviews can be implemented alongside the commencement of each new electricity transmission price control.

Embedded Benefits

- 7.9. The minded-to consultation proposed implementing 'full reform' as our leading option. This option included the following changes:
 - setting the Transmission Generation Residual to zero;
 - charging balancing services charges for demand on a gross basis at the Grid Supply Point so that suppliers cannot reduce their liability for balancing services charges by contracting with Smaller Distributed Generators (and exporting on-site generation); and
 - charging Smaller Distributed Generators balancing services charges in the same way as larger generators.

7.10. Since we published our minded-to consultation, the Balancing Services Charges Taskforce, which was launched at the same time, concluded that balancing services charges should be treated as a cost-recovery charge, as it was found not to be feasible to charge any of the components of balancing services charges in a more cost-reflective and forwardlooking manner.

7.11. We accept this conclusion and do not therefore think that it is appropriate for us to impose this charge on Smaller Distributed Generators at this time.

Next Steps

7.12. We have issued detailed directions alongside this decision in order that modifications to the relevant industry codes can be raised to give effect to the terms of decision. We expect these proposed modifications to be considered through workgroups over the next few months before coming back to code panels to be assessed, and submitted to the Authority in good time to allow implementation according to the timelines referred to above.

7.13. We expect the relevant licensees to work together to:

- ensure consistency of the resulting code modifications and resulting arrangements across the relevant industry codes.
- to present a detailed plan to ensure modifications reach the Authority in good time to make a decision which facilitates implementation in the timelines set out in this decision.
- to take steps to ensure potential issues which could prevent implementation along the timelines set out in these directions are raised in a timely manner with Ofgem, and a process for resolving potential issues in in place.

7.14. We will follow the progress of the modifications and the taskforce to make sure that progress is timely and that the changes will be ready to be implemented for: Embedded Benefits in 2021, transmission residual charges in 2021 and distribution residual charges in 2022.

7.15. In order to facilitate the implementation of our proposals under this decision and the accompanying directions, we may consider using our powers under the 'Duty to Cooperate' electricity licence conditions.¹⁵⁸ This could include requiring licence holders to undertake any reasonable requests in relation to planning, project assurance and/or coordination/systems integration in order to give full effect to the conclusions of our SCR. In addition, the Authority may also issue a 'backstop direction', for example, where development of the modification proposal under the standard industry code process is not meeting the expected policy direction or timescales for implementation.

 $^{^{158}}$ SLC C19 of the electricity transmission licence, SLC 20.10 to 20.12 of the electricity distribution licence and SLC 11.11 to SLC 11.13 of the electricity supply licence.