Northern Powergrid's response to Ofgem's Consultation on a Targeted Charging Review (TCR)

KEY POINTS

- Northern Powergrid welcomes this review which is needed given rapid changes in the structure of the energy market and in how market participants use energy networks.
- The current charging regime requires change in order to send signals that more accurately reflect costs of how the system is now being used. This is needed to drive efficient development of a smarter, more flexible electricity system and to recover prior investment appropriately. In making the changes there is an opportunity to deliver additional benefits such as transparency for customers.
- The more significant issues are at the transmission level where 'residual' charging represents about 80% of transmission charges. This raises concerns over the cost-reflectivity of the current methodology and these issues should be addressed most urgently.
- Changes are required to deal with the market distortion created by behind the meter generation and the potential for 'free riders', which Ofgem also recognises.
  - The issue is particularly of concern due to the majority weighting of distribution revenue recovery via variable unit charges (currently about 80%) which leads to those without generation paying for an undue proportion of network costs.
- The consultation concentrates on the 'residual' element of network charges rather than a wider holistic review of the charging methodologies which we consider necessary.
- We disagree with Ofgem's proposed solution to distribution charges and favour solutions that 'fix at source' the issues identified with charges as opposed to dealing with the consequences of charges that are insufficiently cost-reflective such that there is a high level of 'residual'.
  - Our preferred solution seeks to generate a greater proportion of the charges from the underlying cost-reflective methodology that then reduces the amount of 'residual'.
- Transparency and volatility are important objectives that need to be balanced with the competing aims but come behind cost-reflectivity as the primary driver of change.
- Ofgem's proposed treatment of distribution charging for storage has the potential to introduce positive discrimination in favour of storage technologies, rather than levelling the playing field.
  - If charges in each element of the value chain are cost-reflective, flexibility providers which offer the best value will naturally become prominent in the market.
- We welcome the proposal to set up a Charging Coordination Group (CCG) to oversee the charging work currently being undertaken by the industry.
  - This needs to be led by Ofgem to give strategic direction with support from the industry, to ensure all the good work already carried out by the charging review groups is taken into account and not duplicated.
  - Careful consideration should be given to addressing these issues though working with the CCG, which could save time whilst also delivering improved solutions.

Part 1 – Executive summary

1. Northern Powergrid welcomes the opportunity to respond to Ofgem's consultation on the Targeted Charging Review (TCR) and we are supportive of the work being undertaken to ensure that appropriate charging structures are in place that send efficient and effective cost signals to customers as we transition to a smarter, flexible energy system.

2. The consultation appears to be very narrow in its scope, focussing only on the 'residual' elements of network charges rather than a wider holistic review of charging methodologies, which we consider to be necessary. We note Ofgem's consideration that the forward-looking network charges are part of a broader issue to be taken forward in its joint work on a smart flexible energy system with the Department for Business, Energy & Industrial Strategy (BEIS), and Ofgem's own strategic view of the market and regulatory arrangements. Our responses to this consultation build on our views set out in our earlier response to the call for evidence.

3. We have focused our response on the distribution use of system (DUoS) aspects of the consultation, although it is clear that the consultation is primarily driven from a transmission perspective. We believe that more appropriate solutions may be available to address the perceived concerns at a distribution level and hence Ofgem should be cognisant of the ongoing charging review work that is currently being undertaken in the charging governance groups.

Cost-reflective charging is a policy decision which needs careful consideration in the context of other valid charging objectives such as ability to respond and price stability and predictability

4. Network charges serve two distinct primary purposes, namely: cost-reflectivity and cost-recovery.

5. The first purpose, cost-reflectivity, is to give price signals to users of the network, so as to encourage overall efficient behaviour. From this perspective, the relevant costs to be reflected in charges are forward-looking incremental network costs (which may be materially lower than average costs). Cost-reflectivity has two dimensions:

   - In the short-term, price signals might impact consumption/generation patterns of users already connected to the network. If the network price is high (perhaps because the network is operating at capacity), network users are given a signal to reduce load; and
   - In the long-term, price signals might impact investment decisions of network users. For example, sustained higher network tariffs would provide a signal that it might be more efficient for customers to connect at a different network location or voltage.

6. The optimal degree of cost-reflectivity is a policy question. Here, there are trade-offs with other valid charging objectives, in particular:

   - Ability to respond. If other factors constrain a customer's operating or investment decisions, the customer may not be able to respond to cost-reflective pricing, meaning there will be no efficiency benefit. Equally, the more complex a tariff is, the less likely customers are to be able to respond to those price signals; and

- Stability and predictability of tariffs. Changes to the tariff design which entail large step changes relative to the status quo, or tariff methodologies which can result in volatile tariff changes year-on-year, should be avoided.

7. We believe it is important to consider a further aspect of cost-reflectivity. In addition to providing signals to avoid future costs by influencing behaviour to shift demand away from system peak, it is right to recognise that cost-reflectivity should address the impact users have on the system at present. For charges to be truly cost-reflective, they need accurately to represent the costs users impose on the network, including 'sunk costs', whilst also seeking to provide an incentive for efficient use of the network via forward-looking price signals which may ultimately defer the need for network companies to reinforce or replace assets. This view of cost-reflectivity aligns to the definition within the Council of European Energy Regulators (CEER) 'Electricity Distribution Network Tariffs: CEER Guidelines of Good Practice'[1] document.

New market models should be considered as well as traditional approaches but they must be predictable and fair

8. Cost-reflective DUoS charges are not the only way to encourage efficient outcomes in support of a smart, flexible energy system. Other instruments, such as constrained connection contracts or distribution system operator (DSO) contracts, may also deliver these outcomes - each channel could be used to send signals in relation to operation or investment. A coherent design needs to be adopted to ensure relevant price signals are sent once and once only to avoid double counting price signals, which would lead to inefficient outcomes. For this reason, the approach to network charging must be considered in parallel with the question of the DSO role – the approaches for each cannot be considered separately.

9. The second purpose of network charges is cost-recovery (i.e. to ensure that networks recover their efficiently incurred sunk investments). Ofgem's regulatory model allows customers to benefit from low financing costs because it allows networks to recover efficient past investments from customers over time.

10. It should be noted that network charging facilitates the delivery of several social and financial objectives for Government, such as the socialisation of certain costs, the provision of priority services to vulnerable customers and the management of certain legacy costs.

Outcomes must be good for consumers as a whole and not benefit one sector at the expense of material downside to another – in particular, vulnerable customers need to be protected

11. In principle, cost-recovery can be achieved by tariffs which are specified in any number of ways – for example, they could be based on a charge per connection; a fixed capacity-based charge; or charges based on peak consumption. For the purposes of establishing a charging method for cost-recovery, the question to be answered is how to divide the burden of paying for efficiently incurred sunk costs between different customer groups.

12. In designing this, again there are trade-offs across a number of objectives. Charges to recover sunk costs (over and above estimated forward-looking incremental costs) should generally:

    - be evidence-based and rational;

[1] http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2017/CEER%20DS%20WG%20Best%20Practice%20Tariffs%20GGP%20-%20%20external%20publication_final.pdf

- seek to avoid changing or distorting customer behaviour, since, by definition, customer behaviour can have no impact on legacy costs;
- share the burden of cost-recovery across different customers in an equitable way which is sustainable in the long-term – users should not be able to modify their behaviour to avoid their fair share of cost recovery for sunk costs that then have to be borne by others (the 'free rider' problem);
- ensure that vulnerable customers are protected; and
- be relatively stable and predictable over time.

More complex DUoS tariffs are unlikely to be the most appropriate solution in a smarter, more flexible future

13. In our view, introducing more complex cost-reflective tariffs in order to drive efficient behaviour is likely to have a number of challenges that may not be reconciled with all of the above. We have seen evidence from our Customer-Led Network Revolution (CLNR) study that customers struggle to understand and respond in efficient ways to overly complex network tariff structures[2]. We also observe that even today's relatively straightforward network pricing signals (i.e. the variation in tariffs depending on the time of day or week based on the Red/Amber/Green (RAG) identification) – are not usually passed through to end-users by suppliers. This further suggests that suppliers and customers are unwilling or unable to respond to more complex network charging, since the competitive market has yet to fully translate these signals into retail pricing strategies.

We favour solutions that 'fix at source' the issues identified with charges as opposed to dealing with the consequences of charges that are insufficiently cost-reflective

14. We believe the distinction Ofgem appears to draw between forward-looking and 'residual' (i.e. known as 'scaling' at the distribution level) is over-simplified and we believe at a distribution level it would be more beneficial to address the underlying cost allocation methodology as the first step in reducing the level of the 'residual' value. Ofgem suggest that elements of the 'residual' charge cannot be allocated to consumers. We believe that this is not the case and there is a need to be cognisant of the ongoing work within the industry on wider charging reviews that may reduce the level of the 'residual' charges by better allocating costs, rather than seeking to simply spread the costs they are deemed to represent over different charging elements and/or customer groups.

Transparency and minimal volatility are important objectives that need to be balanced with competing aims but come behind cost-reflectivity as a primary driver of change

15. We welcome Ofgem's recognition that cost-reflectivity can drive additional complexity, and where it is less relevant (such as for 'residual' costs which should not distort the modelled outputs) we agree that charges should be simple, predictable and therefore transparent.
16. We believe that it would be more cost-reflective if the 'residual' charges were recovered by a higher proportion of fixed rather than variable charges and we have proposed a well-supported option to address this perceived imbalance as part of the ongoing distribution charging methodology reviews. This approach seeks to better define sunk costs and forward-

[2] 'Key Learning Report : The role of industrial and commercial and distributed generation customers', available as reports CLNR-L247 from the project library: www.networkrevolution.co.uk/resources/project-library/

looking costs, and allocate these to customers in a more cost-reflective manner. There are costs that cannot be avoided by a consumer's reduced net consumption (e.g. sunk costs); these costs should be borne by all who choose to connect to the system. We consider that fixed charges are appropriate to recover sunk costs, with unit rates, which could include time of use price signals, driving the recovery of forward-looking costs to incentivise efficient behaviour. We believe that the adoption of such an approach would reduce the level of scaling (residual charges) required in DUoS charges.

17. We believe that sunk costs should be fairly allocated to customers to reflect the costs they impose on the network simply by being connected. In connecting a consumer, distribution network operators (DNOs) have invested in the network and this cost is not a function of how much a consumer chooses to use their connection once the connection has been provided.

18. We consider that the industry and ultimately consumers would benefit from a clearer distinction between:

    - forward-looking costs with appropriate time of use incentives to avoid future costs;
    - equitable backward-looking costs which could mitigate the growing 'free rider' issues and in doing so reduce volatility in charges; and
    - any 'residual' charges required to facilitate cost-recovery.

19. In the future these DUoS charges can then be combined with additional flexibility products, for those customers that want to actively participate, as we transition to a smarter, more flexible energy system and the introduction of new DSO arrangements.

20. We agree with Ofgem that under the current price control regimes, the revenue network companies are allowed to recover in a particular year are broadly fixed, with a significant proportion of these revenues reflecting costs already incurred but still to be recovered. We consider this view further supports a rationale for addressing the current balance between fixed and variable charges.

21. Reducing volatility would benefit all stakeholders, and we believe addressing the balance between fixed and variable charges better to reflect reality will help achieve this.

22. However, although a balance is required between sometimes competing objectives, it is cost-reflectivity that is the most important when setting policy and methodologies on charges, as it should ensure that there are no discriminatory or distortionary effects. It also has a significant impact on efficient future network development and the recovery of sunk costs.

23. In general, we agree with Ofgem that the challenge with regards to 'residual' charges is to find a way of setting them so that where they do influence consumer decisions, they do so with positive effects on consumers' wider interests, or at least less harmful ones. However, we believe that in order to tackle this it is necessary to give consideration to reducing the impact of 'residual' charges (i.e. the quantum of costs the residual charge is seeking to recover) rather than seeking to reallocate the current quantum of costs as they currently exist. We therefore support Ofgem's view that a more reasonable objective is to derive 'residual' charges on a basis that will reduce distortions rather than eliminate them.

There is the potential to introduce positive discrimination in favour of storage technologies, rather than levelling the playing field

24. Ofgem's proposed treatment of distribution charging for storage has the potential to introduce positive discrimination in favour of storage technologies, rather than levelling the playing field. It is important that the regulator looks at the full value chain to ensure that equitable and cost-reflective charges are in place.

25. If charges in each element of the value chain are cost reflective, flexibility providers which offer the best value will naturally become prominent in the market.

An Ofgem led Charging Coordination Group (CCG) to set the strategic direction for future charging arrangements is a useful proposal

26. We welcome the proposal to set up a CCG to oversee the charging work currently being undertaken by the industry. However, this needs to be led by Ofgem to give strategic direction with support from the industry, to ensure all the good work already carried out by the charging review groups is taken into account and not duplicated. The scope of the group also needs to be clearly defined and agreed by all parties.

27. In relation to a significant code review (SCR), careful consideration needs to be given to whether the scope of this work (i.e. 'residual' charging alone) is significant enough to require a SCR, or whether it may be better achieved by Ofgem actively participating in the ongoing industry work on charging reviews. This could save time whilst also delivering improved solutions.

28. We welcome the dialogue on these important matters and look forward to discussing the points we raise in this consultation response further.

Part 2 – Responses to consultation questions

Residual Network Charges

Q1. Do you agree that the potential for residual charges to fall increasingly on groups of consumers who are less able to take action than others who are connected to the system, is something we should address?

29. Yes, we agree that this is something which should be addressed. We do not support a position where some consumers are required to pay more as a result of others being able to reduce their charges, which may be achieved as a result of installing technologies (such as battery storage) or private network arrangements for example, but which do not benefit the network to the extent of the avoided charges.

30. The consequence of such technological changes may result in the emergence of network users who are better able to decrease their net demand by installing behind the meter on-site generation, and where this reduction does not lower the overall level of costs which use of system charges are required to recover. We are concerned that the reallocation of the burden this then represents may fall particularly on vulnerable customers who are less able to afford the investment in new low carbon technologies.

31. Ofgem needs to consider carefully the appropriateness of what has been a key principle in establishing the charging methodologies that network companies currently apply; namely cost-reflectivity.

32. Developing a more cost-reflective distribution charging methodology, such as introducing different charges within a DNO's service area for example, could potentially provide fewer opportunities for 'free riding', and in doing so potentially address some other known distortions within the industry.

33. However, this would involve additional complexities being introduced into the methodologies which are widely recognised as already being complex, but arguably do not sufficiently recognise cost-reflectivity in respect of the costs users impose on the network presently. This aspect of cost-reflectivity is arguably sacrificed to focus more on providing price signals to incentivise consumers to reduce future costs. Evidence at the distribution level suggests this has not had the desired impact (e.g. we have seen no change in customer behaviour following the introduction of the three rate R/A/G time of use tariffs despite the very sharp pricing differential).

34. We also recognise that the roll-out of smart meters could change the industry in this regard, better facilitating the ability of domestic users to respond to price signals, provided that appropriate cost signals are included in their supply tariffs.

35. Switching the focus to the costs that users impose on the network, and particularly for distribution charging, we believe that more of the 'residual' charges (known as 'scaling' at the distribution level) can be better allocated to specific consumer groups. The level of allowed revenue allocated via scaling in distribution charges is largely the product of a hypothetical incremental network model (the '500MW model'), and whereby the asset costs underlying this approach are not necessarily reflective of the costs DNOs would incur (for example they are not replacement costs). We believe the costs attributed to variable rates and time of use price signals, and those which could be reflected in fixed charges, can be allocated in a more cost-reflective and better-justified method.

36. We believe that it would be more cost-reflective if the 'residual' charges were recovered by a higher proportion of fixed rather than variable charges and we have proposed an option (well-supported in the industry working group) to address this perceived imbalance as part of the ongoing distribution charging methodology reviews. This approach seeks to better define sunk costs and forward-looking costs, and allocate these to customers in a more cost-reflective manner. There are costs that cannot be avoided by a consumer's reduced net consumption (e.g. sunk costs); these costs should be borne by all who choose to connect to the system. We think this is potentially a better way forward and aligns well to Ofgem's aims expressed throughout the consultation.

37. Figure 1 provides a high-level illustration of the potential impacts on the way that revenue is recovered should such an approach be adopted.

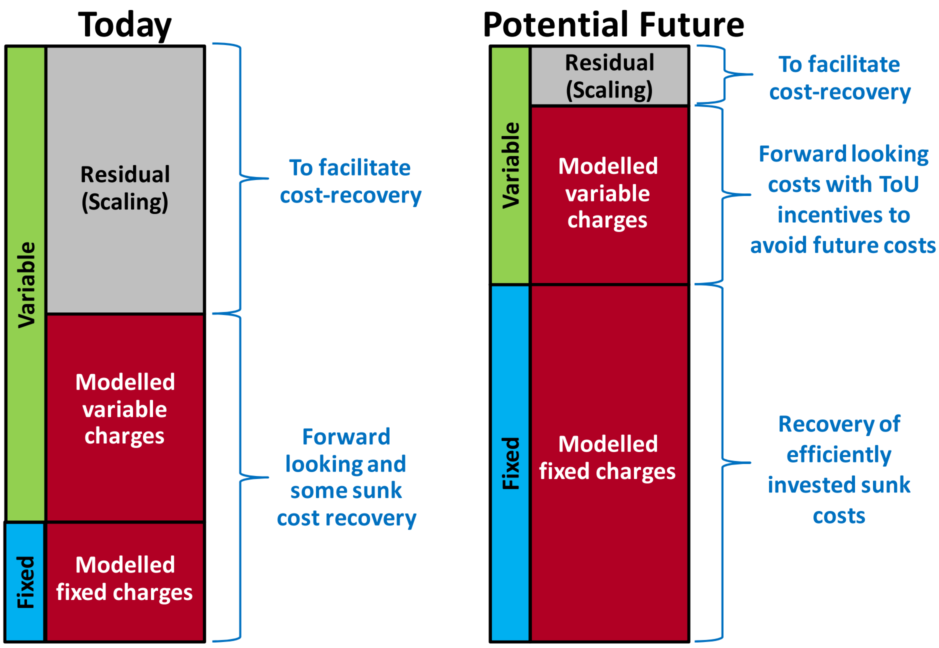

Figure 1 - Option for allocating distribution costs in a more cost-reflective and better-justified method

38. An overview of the current distribution charging methodology is provided in Part 3 of this response and potential charging arrangements are being discussed as part of the ongoing distribution charging methodology review groups, in which we are actively participating.

39. However, to fully address the problem we believe Ofgem and the industry need to look beyond the proposed scope of the TCR and this could represent a Significant Code Review (SCR) that is wider than Ofgem currently envisages.

40. Careful consideration needs to be given to whether the scope of this work (i.e. 'residual' charging) is significant enough to require a SCR, or whether it can be equally well achieved by Ofgem actively participating in the ongoing industry work on charging reviews, which could save time whilst also delivering improved solutions.

Q2. If so, why do you think, or do not think, action is needed?

41. We believe that some costs are unavoidable and should be borne by all. Charging arrangements should not create the potential for further market distortions and undue discrimination toward certain consumers; particularly the vulnerable and fuel poor. In addition, we believe that care needs to be taken with regards to retaining an appropriate balance between charges levied on domestic and non-domestic consumers.

42. We believe there is still scope to improve the current method of scaling within the CDCM and to reduce the distortions that come from applying scaling to the incremental cost signals. However, we believe this requires a fundamental review of the methodologies, as is currently being undertaken as part of the distribution charging methodologies review.

43. We propose that more of the charges should be recovered through a fixed rather than variable basis, which has been recognised as part of the ongoing distribution charging methodologies review. As previously noted, one option under consideration is to split revenue recovery between the recovery of 'sunk costs' (which is proposed to be on a fixed charge basis) and forward-looking incremental costs (which is proposed to be on a variable basis). This is likely to reduce significantly the amount of 'residual' charging required, mitigating some concerns over cost-reflectivity and ultimately fairness, and mitigating some of Ofgem's concerns.

44. The approval of a relatively new demand scaling approach detailed in DCP228 'Revenue Matching in the CDCM' (approved by Ofgem for implementation in April 2018) was an initial step but Ofgem also recognised industry views that this proposal should be subjected to wider consideration.

Q3. We are proposing to look at residual charges in a Significant Code Review. Are there any elements of residual charges that you think should be addressed more urgently? Please say why.

45. The importance of the transmission and distribution network in delivering energy to people's homes and businesses continuously needs to be recognised. The networks are an essential part of a chain which ensures security of supply.

46. We recognise the market concerns outlined in the consultation. Smaller embedded generators (EG) connected to the distribution network can secure benefits from triad avoidance that are not available to larger distribution-connected and transmission generation.

47. We agree that a significant market distortion exists at transmission level and that this should be addressed as a matter of priority, creating a level playing field for all generators and removing the risk of inefficient network development.

48. We welcome the detailed impact assessment of the two Connection and Use of System Code (CUSC) modification proposals (CMP264 and CMP265) along with the 23 workgroup alternatives that were put forward. This has highlighted the level of concern across the industry and the need to address these issues quickly and efficiently.

49. The more significant issues are at the transmission level where 'residual' charging represents about 80% of transmission charges, which raises concerns over the cost-reflectivity of the current methodology and these issues should be addressed most urgently.

50. In terms of charging for electricity distribution we do not believe the issues are as great. Significant progress is currently being made through the ongoing distribution charging methodology review. Ofgem's active participation in these forums could bring this work to a successful conclusion in terms of addressing, or considerably mitigating, the concerns raised in the consultation.

51. However, to address the concerns identified fully we believe that Ofgem and the industry need to look beyond the proposed scope of the TCR and this could represent a wider than currently envisaged SCR.

Experience in other countries

Q4. Are there elements of the approaches in other countries that you think could be appropriate for GB residual charges?

52. The examples reviewed demonstrate that there is a range of approaches to residual charges. It is not clear whether the definition of 'residual' charges in other countries aligns to Ofgem's interpretation.

53. Some other countries' approaches to charging better reflect the balance between fixed and variable costs on the distribution network, and we would welcome Ofgem's views on the most appropriate balance.

54. We believe a system that better reflects the balance between real costs incurred and charges to recover them will also support the transition towards a smarter, more flexible energy system.

55. More complex distribution tariffs are unlikely to be the most appropriate solution in a smarter, more flexible future. We agree with Ofgem that additional complexity in order to achieve better cost-reflectivity is not always the most appropriate solution.

56. There are benefits from the simplicity of charging methodologies that are based on a fixed charge mechanism, as is the case in both Nevada, USA and the Netherlands. Reducing volatility and having use of system charges that provide greater simplicity for consumers introduces the opportunity for better forecasting of network charges resulting in less variability and volatility in prices.

57. We note evidence from the Netherlands suggesting that a move to a more fixed charge basis facilitated the better forecasting of network charges and reduced revenue uncertainty, whilst also suggesting that incentives for energy efficiency remained through other volumetric elements. We welcome the stability this approach promotes, particularly now that GB DNOs are required to give 15 months' notice of changes to use of system charges.

58. We understand that a move to a more fixed charge basis may be seen to lessen incentives on users to reduce overall consumption; however we believe this approach brings significant benefits which more than outweigh this potential weakening of the incentive. Charging would be more predictable as a result of a higher level of revenue recovered on a fixed charge basis, enabling a stronger (potentially seasonal) time of use signal to be included to influence consumer behaviour. Whilst the variable rate(s) would not carry as much weighting as they do under the current methodologies, when viewed in the round this will better achieve the charging principles. It is possible that increased fixed charges could lead to increased demand due to a diminished price signal, however this depends on what price signal energy suppliers pass on to end users, and evidence within distribution charges suggests that at present the signals are not having the desired effect of influencing consumer behaviour to shift demand away from network peaks. We welcome the evidence from the Netherlands suggesting that incentives to influence behaviour have remained.

59. We recognise that there may be a need to consider transitional arrangements and the need for robust analysis in determining an appropriate solution for the GB energy system, and we consider that it will be essential to the success of implementing any changes that Ofgem and the industry ensures there is good communication to reduce any associated disruption which may result for consumers.

Q5. Are there other approaches that you know about from other jurisdictions, that you think offer relevant lessons for GB?

60. We are not currently aware of any significant additional evidence in this regard beyond the examples already detailed in the consultation.

Proposed principles for assessing options

Q6. Do you agree that our proposed principles for assessing options for residual charges are the right ones? Please suggest any specific changes, or new principles that you think should apply.

61. In addition to the three core principles covered in the consultation (namely reducing distortion; fairness; and proportionality and practical considerations), and the relevant charging code objectives (such as cost-reflectivity; facilitating competition; and reflecting the developments in the network businesses), we also believe that there are some important additional charging principles that should also be considered, namely:

- cost-recovery;
- commonality;
- transparency;
- flexibility; and
- protecting consumers by socialising certain costs.

62. It is a positive sign from Ofgem in recognising that cost-reflectivity can result in disproportionate additional complexity, and where cost-reflectivity is less relevant like for ‘residual’ charges which we consider should be recovered utilising more simple charges. We agree that charges should be easy to calculate and understand, therefore improving transparency.

63. The distribution charging principles detailed above have been discussed as part of the current distribution charging methodologies review and Energy Networks Association (ENA) transmission system operator (TSO) to DSO workstream meetings and there is broad agreement that they are the right things to consider.

Options for setting residual network charges

Q7. In future, which of these parties should pay the transmission residual charges: generators (transmission- or distribution-connected), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

64. Residual charges should be recovered fairly from users who have caused these costs (deemed to be sunk costs) to be incurred. There should be consistency in treatment across transmission and distribution to avoid distortions at the network boundaries, which can lead to inefficient dispatch of plant.

Q8. In future, which of these parties should pay the distribution residual charges: generators (transmission- or distribution-connected.), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

65. Consistency in treatment across transmission and distribution would help to avoid distortions at the network boundaries. This could become less of an issue at the distribution level if the emerging alternative methodologies result in a diminished need for and level of scaling; and

where costs which Ofgem considers are represented in 'residual' charges could be allocated on a more cost-reflective basis.

66. Scaling in distribution charges has traditionally been applied only to demand customers as historically the distribution networks have been overwhelmingly demand dominated. Generation has typically been deemed to be helpful to offset load. We do not support the application of scaling to generation unit credits, if the costs deemed to be associated with the 'residual' charge are considered to be 'sunk costs' which generators cannot reduce by exporting units onto the distribution network (as they have already been incurred).

67. We believe at a distribution level it would be more beneficial to address the underlying cost allocation methodology and this could be the first step in reducing the level of the 'residual' value, whilst simultaneously giving a more accurate means of determining the value embedded generation brings to the networks than simply valuing this at the negative of demand charges.

68. In general, costs should be recovered in a fair and cost-reflective way that encourages a safe and secure network at the least cost to consumers, and whereby some consumers are not unduly subsidising others.

Q9. Do you support any of the five options we have set out for residual charges below, and why?

69. Before considering how to allocate 'residual' charges every effort needs to be made to allocate costs on a cost-reflective basis. Where any 'residual' remains, consideration should be given to where the most likely source of inaccuracy lies and this should be the basis of cost-recovery.

70. Based on the current distribution charging methodology, where the primary focus is on deriving appropriate cost-reflective unit rates to give forward-looking costs signals, the 'residual' (which primarily represents sunk costs) should be recovered on a fixed charge basis.

71. The following table provides our initial evaluation of the advantages and disadvantages of the five options detailed in the consultation document.

Option	Advantages	Disadvantages
Option A: A charge linked to net (kWh) consumption.	• Least cost to implement as status quo for distribution. • Relatively simple.	• Increases the likelihood of behind the meter generation ('free riders'). • As a result, other consumers will pay more to compensate (including the vulnerable and fuel poor).
Option B: A fixed price charge.	• Reduce distortions. • Retain the pure forward-looking price signal generated by the cost-reflective element of charges. • Relatively simple. • Everyone would pay their fair share.	• Allocation to different types of consumer. • Diminished price signal (potential to encourage increasing demand and potentially higher charges for all due to a need for network reinforcement).
Option C: Fixed charges set by connection capacity.	• Reduce distortions. • Retain the pure forward-looking price signal generated by the cost-reflective element of charges. • Accounts for customer size. • Relatively simple.	• To be accurate, needs smart metering. • Potential to shift the burden between types of consumer.

Option	Advantages	Disadvantages
	• Everyone would pay their fair share.	
Option D: Gross kWh consumption.	• Everyone would pay their fair share.	• Relies on information being accurate and available, or deeming an appropriate value as an alternative. • Complex.
Option E: A hybrid approach.	• Should ensure that everyone would pay their fair share.	• Complex. • Lack of transparency. • Difficult to implement.

72. Given the evaluation above, and based on the current distribution charging methodology, our current preferences would be to pursue calculating the residual charges on the basis of a fixed price charge (Option B), with fixed charges set by connection capacity (Option C) representing a viable alternative.

Q10. Are there other options for residual charges that you think we should consider, and why?

73. As we said earlier, it would be beneficial to address the underlying cost allocation methodology and in doing so seek to address the balance between fixed and variable charges, and where this could be the first step in reducing the level of scaling required in DNO charges.

74. Beyond the above, there are no other options that we are aware of. The previous list of options covers the full range of possible outcomes.

Q11. Are there any options that you think we should rule out now? Please say why.

75. If the intent is to solely reallocate the existing 'residual' charge (rather than to fundamentally review the cost allocation, which we advocate), we consider that options A, D and E should be ruled out.

76. Option A is the current approach and there is clear evidence that this encourages inefficient private networks and behind the meter generation to the detriment of the generality of users.

77. Options D and E should be discarded due to their additional complexity and lack of transparency to the end user.

Benefits for small embedded generation, relative to other generation

Q12. Do you think we should do further work to analyse the potential effects of the charging arrangements for smaller EG (called 'embedded benefits')?

78. In principle we believe that all generation should be treated the same, so as not to discriminate against one particular technology, voltage or size of customer.

79. Ofgem's minded to decision on CMP264 and CMP265 goes a long way towards addressing the main issue of the transmission network use of system (TNUoS) demand residual payments.

80. By reducing some of these distortions now there is still a potential to consider the other aspects of embedded benefits as part of, or prior to, a more holistic review to encourage the efficient development of the energy system.

Q13. Do you think changes are needed to the current charging arrangements for smaller EG, and when should any such changes be implemented?

81. Where market distortions can be identified these should be addressed at the earliest opportunity in line with the appropriate governance arrangements.

82. In addition, transitional arrangements may need to be considered in order to strike a balance between preventing the further escalation of the current arrangements and the delay in implementation which is likely to reduce consumer benefits. We would therefore suggest that Ofgem should look to remove the potential for these distortions as soon as possible.

Q14. Of the embedded benefits listed in our table, do you think that any should be a higher or lower priority?

83. We recognise that Ofgem has concerns regarding the benefit that EG is able to access and we support a holistic review of some of the wider distortions in order to encourage the efficient development of the energy system. This should include an assessment of the benefits and risks to the transmission and distribution networks and the wider energy system.

84. We consider balancing services use of system (BSUoS) to be a second order concern and could be considered as part of future developments in relation to the development of local balancing and work on flexibility. We would be supportive of such an approach as local balancing and the potential move to a DSO role is something we are already considering. We therefore look forward to the next steps of the Ofgem/BEIS call for evidence on a route map to a Smart Flexible Energy System with respect to both DSO and storage.

Q15. Do you think there are other aspects of transmission or distribution network charging which put smaller EG, or any other forms of generation or demand, at a material disadvantage?

85. The consultation has identified the main areas of concern, although consideration also needs to be given to progressing this review in a manner that recognises the other market distortions that need to be tackled and seek to avoid unintended consequences.

86. We are particularly concerned that the removal of the embedded benefits may result in a stronger case for investors to exploit other distortions by building generation behind the meter, or on a private wire network, potentially creating further market distortions and inefficiency of the system. We have already seen a significant and growing interest in this type of arrangement.

Residual and BSUoS charging for storage

Q16. Do you agree with our view that storage should not pay the current demand residual charge, at either transmission or distribution level?

87. Ofgem's proposed treatment of distribution charging for storage has the potential to introduce positive discrimination in favour of storage technologies, rather than levelling the playing field. It is important that the regulator looks at the full value chain to ensure that equitable and cost-reflective charges are in place.

88. Storage should be appropriately credited where it sufficiently assists network operation, for example by deferring reinforcement. However, storage is not the only technology that may export at times of peak demand and there needs to be clear justification if it is to be valued differently from other flexibility services that could also reduce network costs. Each technology must be able to compete fairly. The starting point for changes to the charging regime is that charges should be cost-reflective.

89. If charges in each element of the value chain are cost reflective, flexibility providers which offer the best value will naturally become prominent in the market. The value from storage may be 'stacked' to realise benefits from trading in the wholesale energy market, reducing the need for network reinforcement, and providing balancing services to the SO.

90. Care needs to be taken that storage is not considered unique in each of its characteristics, for example at the distribution level there are industrial and commercial customers that can also control their import and export to provide network support at system peak. Strong rationale would be needed as to why a storage provider and an industrial customer with onsite generation should be charged differently for providing the same services. There are some unique features of fast response storage in the detail of some planned operating regimes as evidenced in the number of enhanced frequency response applications for which storage should be appropriately valued by the beneficiary of this service (i.e. the SO and not the DNO).

91. Ofgem's position appears to be primarily influenced by transmission in terms of the benefits licensed and licence-exempt generators can access. Care needs to be taken to ensure that any changes to the current charging arrangements are not introducing an undue preference in favour of one particular technology rather than providing a level playing field for all.

Q17. Do you agree with our view that storage should not pay BSUoS on both demand and generation?

92. BSUoS charges, as with all other use of system charges, should be calculated on a cost-reflective basis.

93. Care needs to be taken that storage is not considered unique in each of its characteristics. Strong rationale would be needed as to why a storage provider and an industrial customer with onsite generation should be charged differently.

Q18. Which of the BSUoS approaches describe is more likely to achieve a level playing field for storage?

94. Careful judgement needs to be applied when designing any changes to existing arrangements to ensure these are consistent with providing a level playing field for storage with other technologies.

Q19. Do you think the changes in this chapter should be made ahead of any wider changes to residual charging that may happen in future? Do you agree with our view that these changes should be implemented by industry through the standard code change process?

95. The consultation concentrates on residual charges, and we believe it would be more appropriate to consider these issues as part of a wider, holistic review of charges.

96. Any changes should be progressed under the normal governance arrangements, even if Ofgem decides to undertake a SCR.

97. Any changes should also be cognisant of the notice periods for changes to charges that are currently in place, which differ between transmission and distribution, and which are understood and valued by market participants.

Next steps and moving forward

Q20. We would welcome your thoughts on the potential make-up of a CCG. Please refer to the potential role, structure, prioritisation criteria and assessment criteria.

98. We are supportive of the creation of the CCG, as we have concerns that charging arrangements are being considered in a number of forums. As such, currently, there is the risk that work is being duplicated resulting in inefficient use of the limited valuable resource in this area and adding to the associated costs and speed of delivery.

99. Ofgem needs to lead this process and provide strategic overview and clear direction. It also needs to be actively involved in working groups to ensure that the direction of travel is appropriate, consistent and capable of approval once proposals have been fully developed.

100. We would welcome more detail on the potential terms of reference for the CCG, frequency of meetings and delivery timescales.

Q21. Do you agree with our proposed delivery model, including its scope?

101. We consider there to be a need to retain flexibility in determining an appropriate delivery model. Different methods may be appropriate at different stages of the developments. That said, option iii (Ofgem leads an end-to-end process to develop code modification(s)) undertaken in conjunction with the industry, might lead to the most effective and efficient solution, building on the good work undertaken by the industry to date.

102. There is a potential for a CCG to mitigate the need for a SCR. However, we believe that the solution to the underlying problems must be considered in a wider context than the current scope of the TCR, and a SCR would need to take this into account.

103. We agree that many charging issues are interrelated and impact all consumers to some degree, and we would welcome a process with more Ofgem control and coordination to help drive timely progress of the issues.

Q22. Do you agree that our proposed SCR process is most appropriate for taking forward the residual charging and other arrangements for smaller EG discussed in this document?

104. We have concerns that this work is too focused on a very narrow aspect of charging arrangements (i.e. 'residual' charges), and believe that the solution to the underlying problems must be considered in a wider context than the scope of the TCR, and a SCR would need to take this into account.

105. If a SCR is to be undertaken it should take a holistic review of charging arrangements that considers impacts on both demand and generation customers at all network levels.

Part 3 – Overview of the current Distribution charging methodology

106. DUoS charges apply with respect to customers connected to the distribution network; they are levied on energy suppliers and not directly invoiced to the consumer. The charges reflect the cost of development, operation and maintenance of the network, and form one component of a consumer's electricity bill where typically network costs (transmission and distribution) represent about 25% of an average domestic consumer's bill[3], as demonstrated in the figure below.

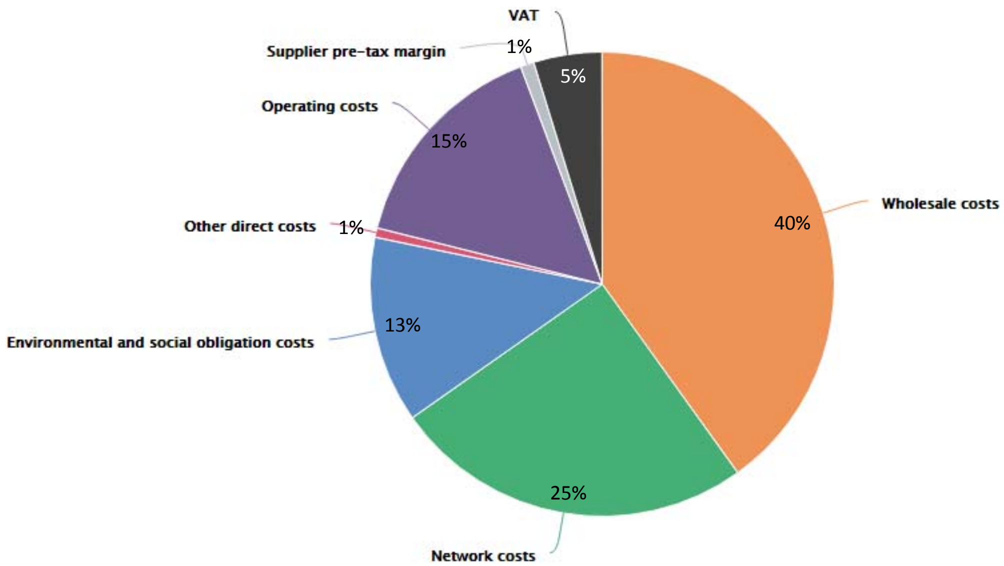

Figure 2 – Breakdown of an electricity bill

107. DNOs must comply with the rules and obligations specified in their Licence conditions and the Distribution Connection and Use of System Agreement (DCUSA). Ofgem approves the charging methodologies, and a DCUSA appointed service provider is tasked with providing spreadsheet models to facilitate the discharge of these approved methodologies.

108. DUoS charges are set to recover a DNO's Allowed Distribution Network Revenue, as defined in the Special Conditions (Charge Restriction Conditions (CRCs)) of their Licence.

109. DNOs are required to provide 15 months' notification of changes to DUoS charges as per the DCUSA, where the Licence stipulates three months'. In setting DUoS charges, DNOs are required to use two common methodologies:

- Common Distribution Charging Methodology (CDCM) – which derives average charges for low-voltage (LV) and high-voltage (HV) consumers. For Northern Powergrid's 2018/19 DUoS charges, CDCM customers are expected to contribute 97% of the targeted revenue; and

- Extra-high voltage (EHV) Distribution Charging Methodology (EDCM) – which derives site-specific charges for designated EHV sites. For Northern Powergrid's 2018/19 DUoS charges, EDCM customers are expected to contribute 3% of the targeted revenue.

[3] https://www.ofgem.gov.uk/consumers/household-gas-and-electricity-guide/understand-your-gas-and-electricity-bills

110. The CDCM has been in force since 1 April 2010, with the EDCM for demand from 1 April 2012 and for combined demand and generation from 1 April 2013. Both methodologies are subject to DCUSA open governance arrangements where any DCUSA party can propose changes.

111. The following figure provides a high-level overview of the CDCM and identifies the model input, calculation and outputs as well as clearly identifying the 'residual' (or scaling) element of the methodology which is the subject of this consultation.

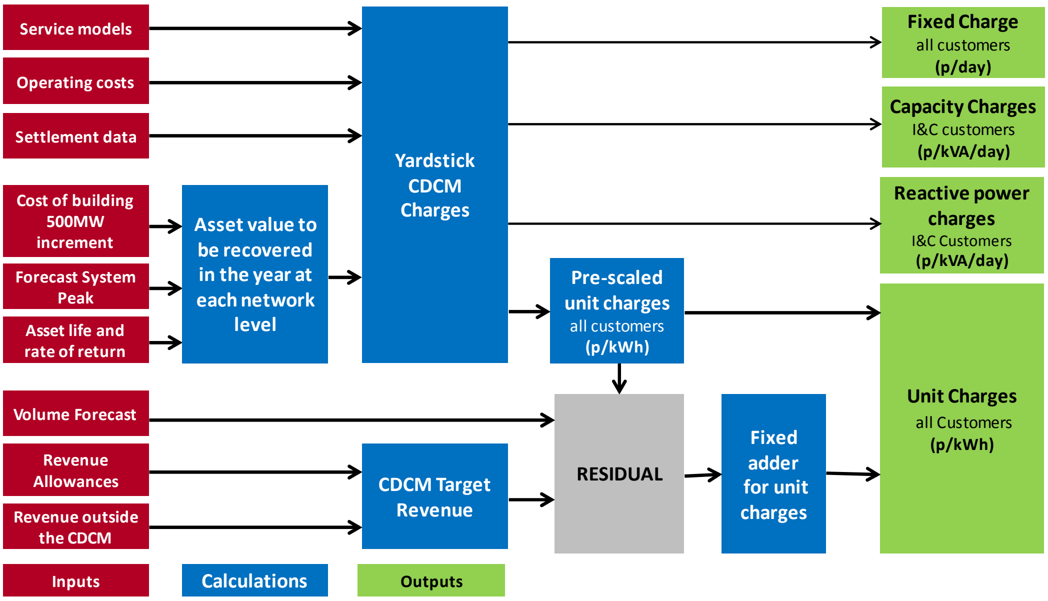

Figure 3 – Common Distribution Charging Methodology (CDCM) overview

112. The methodologies differentiate between the treatment of both demand and generation customers, where for CDCM demand customers, tariffs are structured as follows:

- Fixed charge (p/day) - For half-hourly (HH) settled customers, the charges represent the operation and maintenance costs associated with the service model assets (on the assumption that the asset itself will have been paid for at the time of connection). For non-HH (NHH) settled customers charges include these elements but also a notional capacity value, which is allocated via fixed charges (with the exception of unmetered supply customers who do not have a fixed charge; hence this element is allocated to their unit rates).

- Unit charge (p/kWh) - NHH settled customers' charges are predominantly applied on a single rate basis, but they may also be charged a different rate for off peak consumption depending on the type of meter (e.g. Economy 7 metered customers). HH settled customers' charges are applied on a time of use, RAG basis, reflecting time of system peak with the 'Red' representing peak times and therefore associated higher charges. These price signals are designed to encourage/discourage use of the network at particular times (the times are DNO-specific) and are deemed to provide an incentive for consumers to avoid future costs i.e. to mitigate the need for DNOs to reinforce/replace assets.

- Larger customers (traditionally over 100kW HH metered customers, but now including any non-domestic half hourly settled customers with current transformer (CT) metering) pay capacity charges (p/kVA/day). The capacity charge recovers the costs for assets close to the point of connection and is applied to the maximum import capacity (MIC) a customer reserves on the network. In addition, if a customer exceeds their MIC, excess capacity charges will be applied at a higher rate from April 2018 (about double for Northern Powergrid customers).

113. These larger customers also pay reactive power charges (p/kVArh). These charges are only applied where a customer's power factor is less than 0.95, whereby they are deemed to be inefficient.

114. Revenue recovery is skewed significantly in favour of variable charges, which recover about 80% of Northern Powergrid's allowed revenue, which significantly increases the potential volatility in cost-recovery.

115. The allocation of costs is primarily determined by a hypothetical 500MW model representing the costs associated with creating a new (not replaced) 500MW increment to the existing network, together with service models (representing the cost of sole use connection assets) and other operating costs. The costs are not replacement costs, which would be more expensive than calculating the cost of an incremental addition to the existing network. If replacement costs were included this would likely reduce the level of scaling required (however, it would serve to increase any negative scaling that currently occurs). Additionally, replacement costs would be significantly more expensive at LV than higher network tiers (primarily due to underground cables in built up areas at LV compared to overhead lines in rural areas at EHV), and where this differential serves largely to benefit LV consumers who are essentially cross-subsidised by higher voltages.

116. This method of allocating costs does not result in charges which would allow a DNO to recover its allowed revenue. Scaling, which Ofgem refer to as the 'residual charge' is required to facilitate cost-recovery and ensure that DUoS charges recover the targeted (allowed) revenue. Scaling is applied to the unit rates for demand customers only, and accounts for about 45% of Northern Powergrid's DUoS revenue.

117. Using this approach, in some DNO licensees pre-scaled charges are set to recover too much revenue and negative scaling is therefore required. However, typically pre-scaled charges require positive scaling to be applied.

118. Note that included in the CDCM are charges levied on Licensed Distribution Network Operators (LDNOs), whereby these charges represent the 'all the way' equivalent charges at various voltages, but discounted to reflect the transportation of electricity to consumers that do not utilise the host DNO network from the boundary between the DNO and LDNO networks.

119. For CDCM generation customers:

- HV generators, whether intermittent (e.g. wind) or non-intermittent (e.g. diesel) pay a fixed charge (p/day).
- Generation unit credits (p/kWh) vary according to the type (intermittent or non-intermittent) of generator. Generators receive credits for exporting electricity onto the distribution network regardless of whether they are intermittent or non-intermittent (note: storage is presently treated as non-intermittent). Credits are based on a single unit rate for intermittent generators or time of use RAG rates for non-intermittent generators. Credits are based on the relevant pre-scaled converse demand unit rate, and therefore there is no scaling applied to generation.

- CDCM generation customers pay reactive power charges (p/kVArh). These charges are applied only where a generator's power factor is less than 0.95 unless specifically relating to an agreement to operate this way with the SO.

120. The following figure provides a high-level overview of the EDCM and identifies the model input, calculation and outputs as well as clearly identifying the link to the CDCM charging inputs.

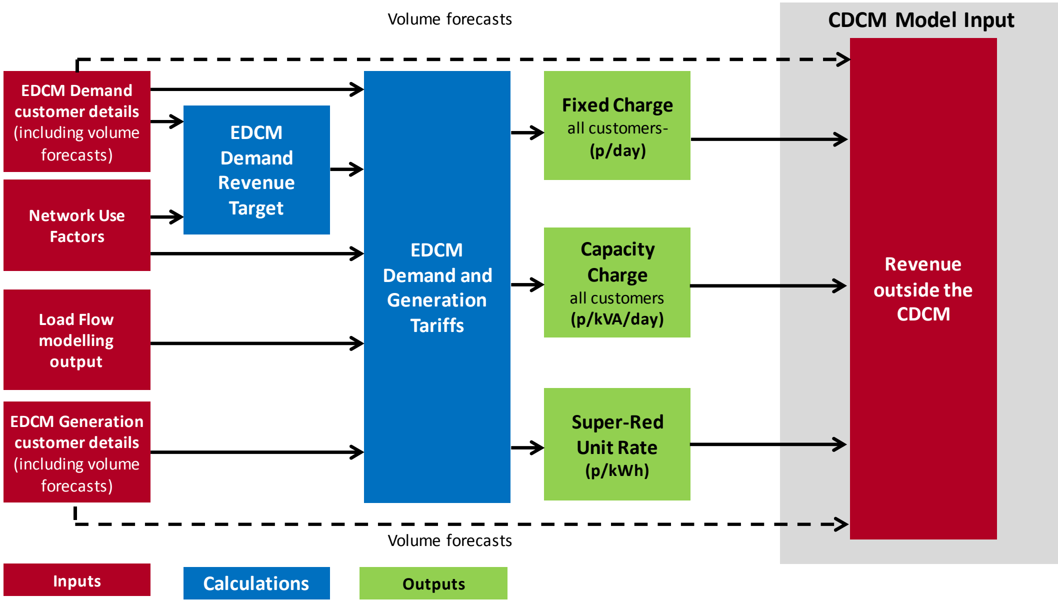

Figure 4 – Extra High Voltage Distribution Charging Methodology (EDCM) overview

121. For EDCM demand customers:

- There are two approved methodologies for calculating EDCM charges as prescribed within the DCUSA, namely Long Run Incremental Cost (LRIC) (Northern Powergrid use this approach) and Forward Cost Pricing (FCP).

- EDCM demand customers pay a fixed charge (p/day). This charge is based on sole-use assets and represents a contribution to direct operating costs and network rates.

- They also pay a capacity charge (p/kVA/day). This element is generally the largest component and is applied to the MIC agreed with the customer. The charge is based on the local (i.e. at the voltage level of connection) element of costs associated with demand-led reinforcement and also reflects (via Network Use Factors (NUFs)) network rates, direct and indirect costs, and an element of scaling (a 'residual' percentage rate applied to shared assets and to the various costs reflected in the charge). If a customer exceeds its MIC, excess capacity charges are applied at the same rate as the agreed capacity charge (no differential unlike CDCM from April 2018).

- There are no reactive power charges for EDCM demand customers.

- EDCM demand customers pay a unit charge (p/kWh). Charges are applied on a time of use basis reflecting time of system peak with only the 'Red' rate applicable, and only in the DNO-specific 'super-red' period (November to February for Northern Powergrid). This represents only a small part of the charge to these customers. This price signal is designed to encourage/discourage use of the network at particular times (the times are DNO-specific) and is deemed to provide an incentive for consumers to avoid future costs i.e. to mitigate the need for DNOs to reinforce/replace assets. The charge is based on the remote (i.e. at voltages above but not including the voltage level of connection) element of costs associated with demand-led reinforcement.

122. For EDCM generation customers:

- Pay a fixed charge (p/day). This charge is based on sole-use assets and represents a contribution to direct operating costs and network rates.
- They also pay a capacity charge (p/kVA/day). This is applied to a customer's agreed maximum export capacity (MEC) and where it reflects an element of operating and maintenance costs. If a customer exceeds its MEC, excess capacity charges are applied at the same rate as the agreed capacity charge (no differential to normal capacity charge).
- They may also receive a unit credit (p/kWh). Only non-intermittent generators are eligible to receive credits. This price signal is designed to encourage units being generated and exported onto the network at particular times (the times are DNO-specific) and is deemed to provide an incentive for consumers to avoid future costs i.e. to mitigate the need for DNOs to reinforce/replace assets. The credit is based on the remote (i.e. voltage levels above but not including the voltage level of connection) element of costs associated with demand-led reinforcement.