

**DCP 284 Collated Consultation responses**

| <b>Company</b>  | <b>Confidential/<br/>Anonymous</b> | <b>1. Do you understand the intent of the CP?</b>  |
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| The Association for Decentralised Energy  | Non-confidential                   | Yes  |
| Good Energy Limited   | Non-confidential                   | Yes  |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential                   | Yes, we understand the wording in the 'intent' section of the CP form. However we do not agree with the arguments presented in the 'Why Change' section. |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential                   | Yes  |
| Western Power Distribution  | Non-confidential                   | yes  |
| Electricity North West Limited  | Non-confidential                   | Yes  |
| Welsh Power Group Limited   | Non-confidential                   | Yes  |
| TGC Renewables Group Limited  | Non-confidential                   | Yes  |
|   | Anonymous                          | Yes  |

| Company   | Confidential/<br>Anonymous | 2. Are you supportive of the principles of the CP?  |
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| The Association for Decentralised Energy  | Non-confidential           | Yes   |
| Good Energy Limited   | Non-confidential           | Yes   |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential           | We are supportive of cost reflective charges for distributed generators. However we do not support the arguments put forward to justify why the change achieves this principle. |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential           | No  |
| Western Power Distribution  | Non-confidential           | yes   |
| Electricity North West Limited  | Non-confidential           | Yes, specifically we support the principle of seeking to improve cost reflectivity where possible and supported by evidence.  |
| Welsh Power Group Limited   | Non-confidential           | Yes   |
| TGC Renewables Group Limited  | Non-confidential           | Yes   |
|   | Anonymous                  | No  |

| Company   | Confidential/<br>Anonymous | 3. Do you accept the interpretation of scaling provided in paragraph 5.11? Provide your rationale for your response.  |
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| The Association for Decentralised Energy  | Non-confidential           | <p>We accept the premise that scaling is applied to maintain the cost signals generated by the CDCM model, but this does not mean that the scaling element is not recovering certain costs.</p> <p>The CDCM recovers the allowed revenue of DNOs which can be broken down into several cost categories and these categories are recovered through the CDCM charges. Consequently, any costs that are not recovered through the yardstick charges, must therefore fall into scaling.</p> <p>Even where the yardstick charges include some cost elements which are not explicit within the breakdown of the allowed revenue (eg the 500MW model) these are a proxy for a one or more of the cost categories within the allowed revenue.</p>   |
| Good Energy Limited   | Non-confidential           | No. Because the target revenue recovers all costs, the scaling of CDCM costs to match the target revenue must also be recovering costs other than CDCM costs, but in a way that preserves CDCM cost differentials.  |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential           | Yes. We agree that scaling is not a means of allocating costs, but is simply a means of enabling the DNO to target allowed revenue whilst maintaining the cost signals generated by pre-scaled tariffs.   |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential           | <p>No.</p> <p>Paragraph 5.11 implies that scaling serves only to maintain differentials between tariff elements whilst enabling the DNO to target allowed revenue. We do not believe that this is the case. Accepting that distribution charges should only reflect costs, one can regard the DNO's Allowed Distribution Revenue as a cost, based upon Ofgem's assessment of necessary costs and returns at the DNO level.</p> <p>Arguably, the concept of preserving tariff differentials is flawed: it treats customer choices between consumptions at different times in a different way from customer choices to consume electricity or not to consume electricity. Thus, if the pre-scaled tariffs provide appropriate incentives, then scaling following the interpretation in paragraph 5.11 would</p> |

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|                                |                  | <p>maintain these incentives as between different kinds of electricity consumption but distort these incentives as between electricity consumption and alternatives.</p> <p>Essentially, paragraph 5.11 focusses on preserving time and locational incentives between different kinds of electricity consumption, whilst potentially distorting incentives targeting energy efficiency by other means.</p> <p>This does not seem appropriate.</p>  |
| Western Power Distribution     | Non-confidential | Yes, this was the conclusion of the DCP228 change report   |
| Electricity North West Limited | Non-confidential | <p>Yes, we fully support this view. In our view the model aims to be reflective of long run incremental costs, but also to recover the allowed revenue due to the DNO party. Scaling, referred to as ‘revenue matching’ in the methodology, is the means by which these two aims are reconciled. Scaling does not represent costs that are missing from the model.</p> <p>DNO revenue is currently based on many things including items such as incentives and correction factors. We do not consider these to be cost items (even if they are ‘penalties’). The element of DNO revenue that is based on DNO’s expenditure generally reflects RAV or historically incurred costs. We do not consider a methodology that includes historic cost elements to be cost reflective. We consider cost reflectivity to be the consideration of costs both currently incurred, and incurred in the future.</p> |
| Welsh Power Group Limited      | Non-confidential | <p>Yes we accept the interpretation of scaling provided in paragraph 5.11.</p> <p>The scaling is applied to the yardstick charges to ensure that the DNO recovers the target allowed revenue. Whilst we agree that the total allowed revenue includes elements not included within the yardstick charges we believe that scaling is intended to maintain the relative charges calculated from the charging models not to explicitly account for these other costs.</p>   |
| TGC Renewables Group Limited   | Non-confidential | <p>We accept the premise that scaling is applied to maintain the cost signals generated by the CDCM model, however our understanding of this is that this does not mean that the scaling element is not recovering certain costs.</p> <p>The CDCM recovers the allowed revenue of DNOs which can be broken down into several cost categories and these categories are recovered through the CDCM charges. Therefore we understand that any costs that are not recovered through the yardstick charges, must therefore fall into scaling.</p> <p>Even where the yardstick charges include some cost elements which are not explicit within the breakdown of the allowed revenue these are a proxy for a one or more of the cost categories within the allowed revenue.</p>  |

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|  | Anonymous | No Comment |
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| Company                                  | Confidential/<br>Anonymous | 4. Under the interpretation provided in paragraphs 5.12 and 5.13, should scaling be applied to generation in the same direction as demand (option a), the opposite direction to demand (option b) or neutral (option c)? Provide your rationale for your response.  |
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| The Association for Decentralised Energy | Non-confidential           | <p>We believe that the correct approach is to apply scaling as specified under option B for the following reasons:</p> <ul style="list-style-type: none"> <li>• Generation charges should be the inverse of the demand charges and option B would preserve this principle.</li> <li>• Ofgem found in DCP228 that “allocating the revenue shortfall or surplus across each of the unit rates on a fixed adder basis as DCP228 proposes would improve cost reflectivity by maintaining the incremental cost differential between unit rates across all tariffs and all time bands.” However, we disagree that Option A is comparable to DCP228. It is important that scaling does not create non-cost reflective distortions between different unit rates, as this would drive different behaviour. However, there is no risk of distortion in DCP284 as it considers generation and demand – generation cannot choose to become demand based on price signals. Option B is focussed instead on ensuring all users, whether generation or demand face equal and opposite cost signals, with any differences in cost impacts recovered on a fixed or capacity basis</li> <li>• The cost elements that we believe to lie within scaling relate to additional capex costs (over and above those specified in the 500MW model) and 40% of indirects. It is appropriate that embedded generation should receive a credit for the additional capex costs as they offset costs for DNOs in this area. It is not appropriate that embedded generation either receive a credit or pay a charge for the 40% of indirects that are recovered within scaling.</li> <li>• Where costs are not related to the level of demand, these are recovered via fixed or capacity type charges. Scaling is applied to unit rates only as it is considered to vary with demand.</li> </ul> <p>Option B would reduce the difference between positive demand charges and negative generation credits whereas option A would increase them. Option A would therefore encourage generation to connect behind the meter, where they can fully capture the benefit of reduced DUoS charges. Option B, on the other hand, would allow generators to capture a similar level of benefits whether connected to the DNOs network or behind the meter.</p> |

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| Good Energy Limited   | Non-confidential | <p>Option b, because this approach would effectively set the generation credits to be the negative of post-scaled demand charges (at voltages above but not including the voltage of connection). It results in a kW of demand reduction or a kW of generation at the same point on a network seeing the same reduction in use of system charges which is correct because they both have the same impact on network power flows. Option b is the only one of the three options which does not incentivise the connection of generation behind the meter. Option c maintains the existing incentive whereas Option a actually increases it.</p> <p>We would also support the consideration of introducing a generation credit floor of zero, as set out in paragraph 5.13. This is necessary to create a regime whereby a unit of generation fully mirrors a unit of demand.</p>   |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential | <p>We believe scaling should not be applied to generation (i.e. option c).</p> <p>The underlying inputs to the CDCM (e.g. the 500MW model) are used to determine the annuitized cost of a 500MW increment to the network, which is then scaled up to forecast system peak. As such, the yardstick tariffs generated by the CDCM (i.e. the pre-scaled tariffs) reflect the contribution required from customers so that the DNO can recover the cost of replacing its network and earn its rate of return over the annuity period. DNOs' allowed revenue is not calculated on this basis, and so scaling is required to enable the DNO to target allowed revenue. This scaling should be applied in a way which does not distort the pre-scaled cost signals. Generation can (under some circumstances) avoid the need for asset replacement and/or network reinforcement in the future, and the extent to which they can do so is accurately represented by the negative of the pre-scaled demand tariffs generated by the forward-looking 500MW model, i.e. the extent to which the generator can offset the need for assets to be installed. Whilst the networks are assumed to be demand dominant, it is appropriate that scaling is recovered from demand customers only.</p> <p>We see no argument why scaling should be applied in the opposite direction to demand (option b), but can see some reasoning for applying scaling in the same direction as demand (option a) in order to maintain the pre-scaled absolute differential between tariffs (as was the principle followed by DCP 228) and enable all customers to contribute to correcting the shortfall/surplus between yardstick tariffs and allowed revenue.</p> |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential | <p>We do not agree that scaling should be applied to generation. Consequently, we do not agree that either options a), b) or c) should be applied.</p>  |

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| Western Power Distribution     | Non-confidential | Option A – the purpose of revenue matching is to achieve allowed income not to allocate costs, therefore maintaining the same absolute pre-scaled differential between tariffs should be the aim. As the consultation indicates, this would reduce the level of generation credits.   |
| Electricity North West Limited | Non-confidential | <p>Applying scaling in the same direction as demand (for ENWL, reducing generation credits by adding an incremental charge) would be consistent with the treatment of demand customers. However, we are concerned that failing to pay generators the marginal benefit they provide to networks would not be in the interests of facilitating competition in the generation market (especially in terms of the efficient allocation of investment between different networks for the benefit of all customers). Furthermore, as scaling is a cost recovery method, not a cost allocation method, we do not believe it would be fundamentally appropriate to apply scaling to credits, as credits do not recover cost.</p> <p>Applying scaling in the opposite direction to demand (i.e. negative scaling increasing credits) would result in tariffs that exceed the incremental benefit provided by generators. We can see no justification for such a policy.</p> <p>On balance therefore we believe neutral scaling of generation credits (option c) would best meet the DCUSA charging objectives.</p> |
| Welsh Power Group Limited      | Non-confidential | <p>We believe the correct method to apply scaling charges is option B.</p> <p>Generation credits are currently set as the negative of pre scaled demand charges. If scaling is to be applied, which we support, it can only be done in a way that preserves this relationship. We believe that both demand and generation should be exposed to equal but opposite signals.</p> <p>Ofgem clearly signalled that scaling should be applied to generation credits ‘we see no obvious reason why DGs should be excluded from such costs.’ and ‘The proposal does not provide any justification to exclude generators from scaling...’</p>   |
| TGC Renewables Group Limited   | Non-confidential | <p>We believe that the correct approach is to apply scaling as specified under option B for the following reasons:</p> <ul style="list-style-type: none"> <li>• Generation charges should be the inverse of the demand charges and option B would preserve this principle.</li> <li>• Ofgem found in DCP228 that “allocating the revenue shortfall or surplus across each of the unit rates on a fixed adder basis as DCP228 proposes would improve cost reflectivity by maintaining the incremental cost differential between unit rates across all tariffs and all time bands.” However, we disagree that Option A is comparable to DCP228. It is important that scaling does not create non-cost reflective distortions between different unit rates, as this would drive different behaviour. However, there is no risk of distortion in DCP284 as</li> </ul>   |

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|  |           | <p>it considers generation and demand – generation cannot choose to become demand based on price signals. Option B is focussed instead on ensuring all users, whether generation or demand face equal and opposite cost signals, with any differences in cost impacts recovered on a fixed or capacity basis</p> <ul style="list-style-type: none"> <li>• The cost elements that we believe to lie within scaling relate to additional capex costs (over and above those specified in the 500MW model) and 40% of indirects. It is appropriate that embedded generation should receive a credit for the additional capex costs as they offset costs for DNOs in this area. It is not appropriate that embedded generation either receive a credit or pay a charge for the 40% of indirects that are recovered within scaling.</li> <li>• Where costs are not related to the level of demand, these are recovered via fixed or capacity type charges. Scaling is applied to unit rates only as it is considered to vary with demand.</li> </ul> <p>Option B would reduce the difference between positive demand charges and negative generation credits whereas option A would increase them. Option A would therefore encourage generation to connect behind the meter, where they can fully capture the benefit of reduced DUoS charges. Option B, on the other hand, would allow generators to capture a similar level of benefits whether connected to the DNOs network or behind the meter.</p> |
|  | Anonymous | In the absence of any more data, option A would be the preferred choice. It would be helpful if we could see some analysis of cost impacts based on actual outputs from a CDCM model with these 3 scaling scenarios applied.  |

| <b>Company</b>   | <b>Confidential/<br/>Anonymous</b> | <b>5. Do you support the view of the proposer provided in paragraphs 5.14 to 5.17 on how scaling is applied? Provide your rationale for your response.</b>   |
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| The Association for Decentralised Energy                       | Non-confidential                   | Yes we agree with this view for the reasons set out in the answer to question 4 above.   |
| Good Energy Limited  | Non-confidential                   | Yes. We believe the principles underlying paragraphs 5.14 to 5.17 to be sound but do not have a view as to whether the percentage of indirect cost affected is 40%, because we have limited knowledge of the detailed costs within the CDCM.         |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) | Non-confidential                   | No.<br><br>The CDCM is not a full cost model, and as such it is fundamentally wrong to attempt to consider costs which have not been included in the 500MW model and attempt to ‘allocate’ them through scaling. Costs which are not included in the |

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| Ltd and Northern Powergrid (Yorkshire) plc  |                  | 500MW model are intentionally excluded in order to derive appropriate forward-looking cost signals, with scaling required to ensure the DNO can target its allowed revenue. These paragraphs are a fundamental misinterpretation of the underlying principles of the CDCM.   |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc | Non-confidential | <p>In part.</p> <p>The assertions in paragraph 5.14 seem contradictory to those in paragraph 5.11. Notwithstanding that, there seems to be some confusion between capital and revenue. Depreciation and return on capital do not seem to have been considered.</p> <p>Additionally, a portion of the DNO indirect costs are incurred supporting activities for network asset construction or replacement – these are allocated to capital expenditure. The proposal doesn't take account of this allocation of indirect costs.</p> |
| Western Power Distribution  | Non-confidential | The overview provided in 5.14 is correct. In terms of whether 500MW model costs can be described as capital costs, clearly they are an assessment under a hypothetical increment of peak demand situation but they are not going to necessarily be consistent with capital spending programmes. The two things are different.  |
| Electricity North West Limited  | Non-confidential | No, we do not support this view. We do not believe that scaling is a cost recovery method. Nor do we believe that it is correct to view DNO revenue as composed entirely of cost elements.   |
| Welsh Power Group Limited   | Non-confidential | We agree with the view of the proposer   |
| TGC Renewables Group Limited  | Non-confidential | Yes we agree with this view for the reasons set out above in our answer to question 4.   |
|   | Anonymous        | No Comment   |

| Company   | Confidential/<br>Anonymous | 6. Do you agree with the definition of residual scaling provided in paragraphs 5.27 and 5.28? Provide your rationale for your response.   |
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| The Association for Decentralised Energy  | Non-confidential           | Yes, we agree with the concept of residual scaling. 40% of indirect costs are not recovered via the yardstick costs, but must be recovered, so automatically fall into scaling.   |
| Good Energy Limited   | Non-confidential           | Yes, we agree with the principle of residual scaling but do not have a view as to the cost elements involved, because we have limited knowledge of the detailed costs within the CDCM.  |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential           | <p>No.</p> <p>As per our response to question 5, it is wrong to attempt to consider costs which have not been included in scaling.</p> <p>Even if one were to accept this premise, the claim that ‘the asset can be replaced with a smaller capacity asset which is therefore cheaper’ is to misunderstand the issue of asset replacement costs being excluded from the CDCM. It is not that the cost of the replacement asset itself is excluded; it is the cost of replacing an existing asset over and above the cost of installing a new asset in unmade ground which is excluded. Replacing an existing asset with a smaller asset will not significantly influence this cost - when a trench is dug in a road to replace a large cable, regardless of whether the large cable is replaced with an equivalent size cable or with a smaller cable, the cost of digging the trench and remaking the road will be broadly the same. Generators are already remunerated for the fact that a smaller asset may be needed through their existing credits being set to the negative of pre-scaled demand charges which include the cost of assets themselves.</p> |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential           | <p>No.</p> <p>If we understand that both allowed revenue and pre-scaled revenue are estimates of the DNO costs (including return on capital) to provide the relevant distribution services, differences between the two numbers can arise from many sources, including the sharing of efficiency improvements and different asset amortisation policies, as well as the treatment of replacement costs. The proposer does not seem to offer any evidence to support the assertions in paragraphs 5.27 and 5.28 and we do not believe that the costs discussed can be as discretely labelled.</p> <p>It seems that the proposer considers that the treatment of replacement costs in the CDCM is inappropriate in a way that affects export tariffs. We are not convinced that a change to the allocation of scaling is an appropriate vehicle to address that apparent concern.</p>   |
| Western Power Distribution  | Non-confidential           | Residual scaling probably does include an element of uncaptured asset replacement costs, as that element is excluded from the CDCM methodology.   |

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| Electricity North West Limited | Non-confidential | As previously stated, we do not believe that scaling (revenue matching) is a cost reflective charge, but rather is applied to recover the allowed revenue while maintaining long run incremental cost signals.<br><br>The proposer raise concerns about the 500MW model that we believe may be better met by making changes to the 500MW model so it includes generators. This would facilitate pricing of the benefits of generation on a long run incremental cost basis. However, such a change is outside of the scope of this proposal. |
| Welsh Power Group Limited      | Non-confidential | We agree with the definition of residual scaling.  |
| TGC Renewables Group Limited   | Non-confidential | Yes, we agree with the concept of residual scaling. 40% of indirect costs are not recovered via the yardstick costs, but must be recovered, so automatically fall into scaling.  |
|                                | Anonymous        | No Comment   |

| <b>Company</b>  | <b>Confidential/<br/>Anonymous</b> | <b>7. Is the current level of capex or the 500MW model a better indication of the avoided cost of embedded generation? Provide your rationale for your response.</b>  |
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| The Association for Decentralised Energy  | Non-confidential                   | We believe that capex is a better proxy of the cost that is avoided by embedded generation. This is because the 500MW model is hypothetical and is therefore based on a number of assumptions. The impact of these assumptions can clearly be seen to be different across the DNOs, particularly in the UKPN London area where the 500MW expenditure is much greater than the allowance for capital expenditure under the allowed revenue. By including scaling, under option B, into the calculation of generation credits it allows the credits to reflect the actual level of ongoing expenditure across the DNOs. |
| Good Energy Limited   | Non-confidential                   | DCP 284 refers to Ofgem having identified a lack of commonality within the 500MW model between DNOs. The wide variability across DNOs in the level of scaling required supports this view and suggests that the current level of capex would be a better indication of the avoided cost of embedded generation than the 500MW model.  |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern | Non-confidential                   | We do not recognise the attempted definition of 'current level of capex'. If the proposer's intent is to allocate costs based on current capex, the price control settlement would provide the required information, but we consider this is a change which goes well beyond the scope of this CP.  |

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| Powergrid (Yorkshire) plc   |                  | The proposer also appears to confuse annual capex with 'residual scaling' – we do not recognise the suggested link between these two. 'Residual scaling' (as defined in the CP) is based on total allowed revenue which includes elements of capex, but also significant recovery of 'sunk costs' which relate to past expenditure.   |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc | Non-confidential | <p>It is not clear from the consultation document how the "current level of capex" would be defined or used to calculate generation credits.</p> <p>On the other hand, we do understand how the CDCM currently uses the 500MW model to estimate the assets that have been rendered unnecessary by embedded generation, and to provide export credits which reflect an allocation of operating costs and an annuity on this notional asset value. The annuity contains both a return on capital element and an amortisation element, and therefore includes a contribution to asset replacement costs.</p>       |
| Western Power Distribution  | Non-confidential | They are two different things – one is based on actual incurred cost and the other is based on hypothetical models. In terms of avoided cost the current level of capex would be a more definite medium term assessment of avoided cost, whereas the 500MW might provide a better long run view.  |
| Electricity North West Limited  | Non-confidential | The level of capex can vary significantly from year to year, and such investments are made on the basis of the long term benefits they bring to the network. The nature of such investments and distribution networks is that some capex expenditure would not be avoided as a result of embedded generation, while other network capex would be avoided as a result of embedded generation. Due to the nature of capex investment we believe that the long run incremental costs of the 500MW model provide a better basis for estimating the benefits of embedded generation than the current level of capex. |
| Welsh Power Group Limited   | Non-confidential | We believe that capex is a better indication of avoided cost of embedded generation since the 500MW model is a hypothetical model and not necessarily related to real world investment decisions  |
| TGC Renewables Group Limited  | Non-confidential | We believe that capex is a better proxy of the cost that is avoided by embedded generation. This is because the 500MW model is hypothetical and is therefore based on a number of assumptions. These assumptions can clearly be seen to be different across the DNOs, particularly in the UKPN London area where the 500MW expenditure is much greater than the allowance for capital expenditure under the allowed revenue. By including scaling, under option B, into the calculation of generation credits it allows the credits to reflect the actual level of ongoing expenditure across the DNOs.         |
|   | Anonymous        | No Comment  |

| Company   | Confidential/<br>Anonymous | <p><b>8. What level of scaling as generation credits should be applied?</b></p> <ul style="list-style-type: none"> <li>• 50% of scaling (in line with the initial proposal);</li> <li>• 65% scaling (in line with the Proposers assessment);</li> <li>• 0% (in line with the current DCUSA);</li> <li>• Any other value (if so please indicate what that value is); or</li> <li>• DNO specific values.</li> </ul> <p><b>Please provide a rationale for your choice.</b></p>  |
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| The Association for Decentralised Energy  | Non-confidential           | We believe that the value of 65% should be used as this value is based on historical values and is therefore a better proxy. Alternatively, the value could be calculated as a rolling average each year from a number of preceding years.   |
| Good Energy Limited   | Non-confidential           | We believe that 65% scaling as derived in Table 2 provides a reasonable basis for the level of scaling as it uses most recent historic data. However, it would be preferable for Table 2 to be repeated for one or more earlier years within the same price control period and, if the results are significantly different, use an average of 2 or 3 years. It is essential that a balance is struck between delivering an appropriate level of scaling, such as through a 3-year rolling average, and that charges are stable and predictable. Significant step-changes should be avoided, such as those which could occur with a change in price control period. |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential           | As per our answer to question 4, 0%. We do not believe any other value can be justified.   |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential           | As we do not support the concept of scaling generation credits, we see the existing level of 0% as the only appropriate value.   |

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| Western Power Distribution     | Non-confidential | The 65% figure at least seems to have a basis for it.  |
| Electricity North West Limited | Non-confidential | 0%, in line with our response to question 4.<br>If an alternative solution was selected we would favour using DNO specific values to best reflect the nature of the DNO's network.   |
| Welsh Power Group Limited      | Non-confidential | We believe the principle of scaling should be applied to generation credits but see no reason why an average value should be used. Since each DNO calculates their own charges and scaling factors a DNO specific value should be used. We believe the DNO specific scaling factor to be applied to generating credits should be the same as that applied to demand charges. |
| TGC Renewables Group Limited   | Non-confidential | We believe that the value of 65% should be used as this value is based on historical values and is therefore a better proxy. Alternatively, the value could be calculated as a rolling average each year from a number of preceding years.   |
|                                | Anonymous        | It would be helpful if we could see some analysis of cost impacts based on actual outputs from a CDCM model with these scaling scenarios applied.  |

| <b>Company</b>                           | <b>Confidential/<br/>Anonymous</b> | <b>9. Do you consider that the proposal better facilitates the DCUSA Charging Objectives? Please give supporting reasons.</b>   |
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| The Association for Decentralised Energy | Non-confidential                   | Yes, we believe that this change modification results in more cost reflective tariffs for generation and therefore better meets charging objective 2 (by promoting competition) and charging objective 3 (by resulting in charges that more closely reflect the costs of DNOs).   |
| Good Energy Limited                      | Non-confidential                   | The proposal makes generation credits more reflective of the cost savings to DNOs from generator export on to their networks which better facilitates DCUSA Charging Objective (3). The proposal increases revenue streams for export from distribution connected generators and provides more accurate price signals which encourage more efficient dispatch and siting of generators, which better facilitates Objective (2):competition in the generation and supply of electricity. |

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| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential | No.<br><br>As our responses to question 4 and 8 suggest, we believe the status quo better facilitates the charging objectives (specifically objective 3 which would be detrimentally impacted by all other options) than any of the other options proposed.  |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential | No. The proposal as formulated would not improve cost-reflectivity or remove impediments to competition. It would have a neutral impact on practicality and transparency.<br><br>Further, it's clear that the most likely outcome of this proposal is an increase in demand DUoS charges – potentially of a significant extent in the north of Scotland area in particular – which we believe to be unjustifiable. |
| Western Power Distribution  | Non-confidential | Not clear, but on balance it does seem inconsistent to not apply some scaling to generators as with demand customers, so in that sense it would seem charging objectives 2 and 3 are better met.   |
| Electricity North West Limited  | Non-confidential | No, primarily we do not consider scaling (revenue matching) to be a cost allocation method.  |
| Welsh Power Group Limited   | Non-confidential | Yes. We believe the application of scaling to generation tariffs will introduce more cost reflective tariffs maintaining the relative differentials calculated from the yardstick charges.   |
| TGC Renewables Group Limited  | Non-confidential | Yes, we believe that this change modification results in more cost reflective tariffs for generation and therefore better meets charging objective 2 (by promoting competition) and charging objective 3 (by resulting in charges that more closely reflect the costs of DNOs).  |
|   | Anonymous        | No Comment   |

| Company   | Confidential/<br>Anonymous | 10. Are you supportive of the proposed implementation date of 1 April 2019?   |
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| The Association for Decentralised Energy  | Non-confidential           | Yes   |
| Good Energy Limited   | Non-confidential           | Yes   |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential           | Not applicable – we are not supportive of the CP.   |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential           | We do not support implementation of this CP so do not support the proposed implementation date.   |
| Western Power Distribution  | Non-confidential           | Yes, if it were approved  |
| Electricity North West Limited  | Non-confidential           | Yes, this is an appropriate date as charges for this period have not yet been issued.   |
| Welsh Power Group Limited   | Non-confidential           | Yes   |
| TGC Renewables Group Limited  | Non-confidential           | Yes   |
|   | Anonymous                  | If the proposed changes are going to have a significant negative impact on tariffs for our customers then we wouldn't be supportive of such an early implementation if the modification was approved. |

| Company   | Confidential/<br>Anonymous | 11. Do you have any other comments on the DCP 284?   |
|---|----------------------------|--|
| The Association for Decentralised Energy  | Non-confidential           | No   |
| Good Energy Limited   | Non-confidential           | No   |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential           | <p>Whilst we do not agree with the proposers interpretation of scaling, if we were to accept the premise then some areas will need more attention.</p> <p>Paragraph 5.30 of the consultation document explains that indirect costs do not vary with demand. This being the case, we do not see why generators should be exempted from the scaling applied to demand customers for the 40% of indirects which the proposer identifies as ‘costs recovered through scaling’.</p> <p>Generators are receiving credits for the 60% of indirects which are included in pre-scaled tariffs. Under the proposers argument this is not appropriate (the proposer acknowledges that indirect costs “are not avoidable by embedded generation”), in which case, under the proposer’s view, scaling should be used to reverse the benefit already awarded to generators for the 60% of indirect costs included in yardstick tariffs.</p> <p>For the avoidance of doubt, we do not support the arguments put forward here for ‘back-calculating’ a removal of indirect costs from generation credits, but merely point out one of many flaws in the arguments put forward by the proposer.</p> |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential           | <p>We note that paragraph 5.25 states that ‘distribution networks continue to be demand dominated and embedded generation is contributing to reducing the size of the networks’. We do not agree that this statement is universally true and note the significant numbers of exporting GSPs in the north of Scotland, the growth of generation-dominated areas in some regions and the extent of network reinforcements being undertaken to accommodate generation rather than demand. It does not seem at all appropriate in such circumstances to increase the levels of generation credits.</p>   |
| Western Power Distribution  | Non-confidential           |  |
| Electricity North West Limited  | Non-confidential           | No   |

|                              |                  |   |
|------------------------------|------------------|---|
| Welsh Power Group Limited    | Non-confidential | No  |
| TGC Renewables Group Limited | Non-confidential | No  |
|                              | Anonymous        | If we could get a better handle of what the size of the impact of this change might be on end consumers then that would allow us to understand and manage this change better. |

| <b>Company</b>  | <b>Confidential/<br/>Anonymous</b> | <b>12. Are you aware of any wider industry developments that may impact upon or be impacted by this CP?</b>  |
|---|------------------------------------|--|
| The Association for Decentralised Energy  | Non-confidential                   | The CDCM review may impact on this proposed change   |
| Good Energy Limited   | Non-confidential                   | The ongoing review of the CDCM and EDCM including any relevant outcomes from the current workshops.  |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential                   | <p>The CDCM review is progressing, and may lead to a fundamental change to the underlying costing model to ensure that generation is taken into account. This being the case, a model which more appropriately reflects the benefits distributed generation brings to DNO networks is likely to be used. With the CDCM review looking to implement changes as early as April 2020, this DCP may only be in place for a single year, causing potentially significant tariff disturbance for no benefit.</p> <p>In addition there has been a lot of debate about the issue around whether CDCM generators should receive credits if there are contributing to the issue of exporting GSPs. There has been a lot of work already carried out to look at this and it remains an issue that needs to be addressed, should this become more prevalent.</p> |
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc               | Non-confidential                   | <p>Primarily, DCP283, which would also increase CDCM generation export credits.</p> <p>Potentially, there may be an element of double counting between DCP284 asset replacement costs and DCP283 contribution factors.</p>   |

|                                |                  |  |
|--------------------------------|------------------|--|
| Western Power Distribution     | Non-confidential | There is the CDCM/EDCM review currently taking place and also Ofgem/BEIS call for evidence on flexibility.   |
| Electricity North West Limited | Non-confidential | CDCM-EDCM Review, Ofgem Smart, Flexible Energy System work and DNO DSO transition work could all impact on this area. While we do not believe these activities should prevent urgent changes been undertaken, we would urge all parties to consider this wider context before progressing change requests. |
| Welsh Power Group Limited      | Non-confidential | No   |
| TGC Renewables Group Limited   | Non-confidential | The CDCM review may impact on this proposed change   |
|                                | Anonymous        | One of the possible outcomes of this modification is that it will provide greater benefits for embedded generators. Could this add to the issues (distortion of the market and removal of level playing field with other generators) that live CUSC modifications like CMP 264/265 are trying to avoid?    |

| <b>Company</b>  | <b>Confidential/<br/>Anonymous</b> | <b>13. Are there any alternative solutions or unintended consequences that should be considered by the Working Group?</b> |
|---|------------------------------------|---|
| The Association for Decentralised Energy  | Non-confidential                   | No.   |
| Good Energy Limited   | Non-confidential                   | We are not aware of any alternative solutions.  |
| Northern Powergrid on behalf of Northern Powergrid (Northeast) Ltd and Northern Powergrid (Yorkshire) plc | Non-confidential                   | No.   |

|   |                  |  |
|---|------------------|--|
| Southern Electric Power Distribution plc and Scottish Hydro Electric Power Distribution plc | Non-confidential | <p>The single largest concern is the potential negative impacts (i.e. increased DUoS costs) for CDCM demand customers which would result from implementation of this CP. We believe that this would be particularly significant in our north of Scotland DSA.</p> <p>In the period whilst the CDCM review is under way, we do not consider it appropriate to increase levels of generation credits, particularly those associated with intermittent generation which are of questionable validity.</p> |
| Western Power Distribution  | Non-confidential |  |
| Electricity North West Limited  | Non-confidential | No   |
| Welsh Power Group Limited   | Non-confidential | No   |
| TGC Renewables Group Limited  | Non-confidential | No.  |
|   | Anonymous        | No   |