

DCUSA DCP 123 Consultation Responses – Collated Comments

Question One	Do you understand the intent of the DCP 123?	
	Responses	Working Group Comments
British Gas	Yes. The intent of the change proposal is to determine a more cost reflective and less distortive approach to scaling. This should ensure that final charges are not excessive for any tariff element.	The working group noted that all respondents understood the intent of the CP.
GTC	Yes	
IPNL	Yes	
Northern Powergrid	Yes	
Npower	Yes	
Scottish Power	Yes, we understand the intent of the change. The current application of scaling to the red/day time band only does not reflect the true costs relating to this period and could therefore be considered to be not cost reflective.	
SP Distribution/SP Manweb	Yes we understand the intent of DCP 123.	
Southern Electric Power Distribution and Scottish Hydro Electric Power Distraction.	Yes	
SSE Energy Supply	Yes	
UKPN	Yes	
Western Power	Yes	
Question Two	Are you supportive of the principles of DCP 123?	
	Responses	Working Group Comments
British Gas	Yes. In our view, by applying scaling to the peak time band	Noted

	<p>consumption only, the current CDCM is distorting the economic cost signals provided by the pre-scaled tariff rates, and is also likely to be producing excessive charges in the red timeband.</p> <p>However we do not believe that both options resolve these issues. Option 1 scaling (% multiplier) is fundamentally flawed because it does not maintain the economic cost signals provided by the pre-scaled tariff rates. Option 1 scaling also does not solve the issue of excessive charges in the red timeband. We are not supportive of option 1.</p>	
GTC	<p>We understand the issues that arise from applying scaling factors to the red band. However, we believe the fundamental flaw is more to do with the amount of allowed revenue that needs to be scaled rather than the method of scaling.</p> <p>We believe this arises from fundamental flaws in the CDCM in that it fails to model significant elements of costs incurred in managing and operating the distribution system. Two of these components are the costs for the replacement of assets and the costs of excavation and reinstatement. Additionally, assets are depreciated over a much shorter time period than the asset life.</p> <p>We believe a more appropriate enduring solution will be to include total costs in 500MW model.</p> <p>Notwithstanding the above, we are only support the principle if the changed way of scaling can clearly be shown to be more cost reflective.</p>	<p>The Working Group noted that the CDCM does not model certain costs but agreed that this is a fundamental approach rather than a flaw of the model.</p> <p>The Working Group noted that the DCMF MIG is reviewing the treatment of asset replacement.</p>
IPNL	We are not convinced that the case for adopting this particular proposal has been made.	Noted
Northern Powergrid	Yes	Noted

Npower	Yes	Noted
Scottish Power	Yes, we are supportive of the principles of DCP 123 to improve the costs reflectivity of charges.	Noted
SP Distribution/SP Manweb	Yes we are supportive of the principles of DCP 123.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	Yes	Noted
SSE Energy Supply	Yes. However we are concerned about the accompanying one-off changes to domestic prices, SME prices and HH customer prices in non peak periods.	The Working Group noted that any change made to scaling is likely to result in a step change. The hope is that going forward the change to scaling will reduce volatility.
UKPN	Yes	Noted
Western Power	Yes	Noted
Question Three	Do you consider that the proposal better facilitates the DCUSA Objectives? Please provide supporting information.	
	Responses	Working Group Comments
The Working Group noted that a significant proportion of the responses to question three mentioned that the Change Proposal better reflects the pre-scaling cost signals. The group discussed this and agreed that the cost message related to incremental costs.		
It was noted that Option 2 places all of the scaling onto the unit rates. It was asked whether the service models should be affected by the scaling.		
British Gas	<p>We do not believe that option 1 scaling (% multiplier) better meets CDCM and general objectives.</p> <p>We believe option 2 scaling (fixed p/kWh) better meets CDCM and general objectives 1, 2 and 3.</p> <p>Option 2 scaling better meets CDCM objective 1 by producing final charges which maintain the economic cost signals contained in the pre-scaled tariffs calculated by the model. By not distorting the economic cost signals between the tariffs and voltage levels the final tariffs will provide customers with the correct time of day cost message and so facilitate the</p>	Noted.

	<p>development, maintenance and operation of efficient, co-ordinated, and economical distribution networks.</p> <p>Option 2 scaling better meets CDCM objective 2 by reducing the volatility of DUoS tariffs (after the one-off step change on implementation). It does this because the amount of revenue recovered from scaling is spread over a much larger volume of units thereby reducing the risk of DNO forecast error and therefore over or under recovery of allowed revenue. Less volatile tariffs will support competition in the supply of electricity, especially if the volatility is not predictable. Also, by significantly reducing the cost exposure to the very narrow red timeband option 2 will also support competition in the supply of electricity by reducing the risk that suppliers carry in forecasting their customers consumption in this timeband. Whilst large suppliers may be better protected against significant changes in individual customers consumption profiles, smaller suppliers are likely to be less protected and therefore option 2 scaling will also better meet CDCM objective 2 for this reason.</p> <p>Option 2 scaling better meets CDCM objective 3 by applying a fixed adder (p/kWh) to the pre-scaled tariffs, thereby maintaining the differential in the economic cost signals contained in the pre-scaled tariffs and improving the cost reflectivity of final tariffs versus the current method of scaling (and also versus option 1 scaling).</p> <p>We do not believe that option 1 scaling (% multiplier) better meets the DCUSA objectives.</p> <p>Whilst option 1 scaling will also reduce the volatility of DUoS tariffs and will slightly reduce the distortion to the cost signals between tariffs contained in the red timeband, it will</p>	
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	<p>increase the distortion between tariffs in the other timebands and therefore it can not be shown to better meet CDCM and general objectives 1 and 3. For a time of day signal to be effective, the absolute difference between timebands and tariffs needs to be maintained. Option 1 scaling is flawed because it significantly distorts the time of day signals contained in the pre-scaled tariffs. This is likely to lead to the development, maintenance and operation of inefficient and uneconomical distribution networks.</p> <p>We also have significant concerns that option 1 scaling still causes a large and potentially excessive amount of scaling to be recovered in the red timeband tariff and in one instance (SHEPD LV UMS) it even causes more scaling to be recovered in the red time band compared to the current scaling method.</p>	
GTC	<p>Whether the CP satisfies the objective will depend on the solution proposed and whether the solution can be demonstrated to be better than the status quo – something which has yet to be demonstrated.</p> <p>Our logical conclusion is that only Option 1 can be demonstrated as better meeting the objectives. Even so we believe Option 1 is only attempting to mask a greater issue with the CDCM: That is the level allowed revenue that needs to be scaled.</p> <p>To allocate the “unallocated revenue” to one tariff component or another creates the illusion that there is an understanding as to which costs this revenue relates and which customer level or network tier the costs relate.</p>	Noted

	<p>If it cannot be demonstrated to what these costs relate we believe the only way to scale CDCM outputs to match allowed revenue is through the application of a simple scaler; i.e. a scaler that applies equally to all tariff components.</p> <p>Whilst we agree that the applying the scaler to the red time band is (and always has been) unreflective of costs we note that this an approach originally approved by Ofgem. Therefore in putting forward alternative options it needs to demonstrate why the original thinking was incorrect and why the proposed options are more cost reflective. The consultation only expresses a view (in paragraph 3.3):</p> <p>“It is the view of the Working Group that either of the proposed approaches would result in an improved scaling approach when compared to the baseline.”</p> <p>As the only supporting evidence for the change.</p>	
IPNL	We believe the proposed Option 2 will have an adverse effect on IDNO revenues (see below) so will not be neutral in its effects on competition (CDCM objective 2)	Noted
Northern Powergrid	We agree with the change proposal that the proposal better meets CDCM Objective 3 by not forcing unallocated allowed revenue (i.e. the scaling amount) into one time band and so the unit costs in those peak time bands (day or Red unit rates) will better reflect the underlying cost message driven from the methodology pre-scaling.	Noted
Npower	Against the third CDCM objective, the change proposal better meets the objective by spreading unallocated costs across all charge elements rather than into one time band as such day or Red unit rates will better reflect the underlying cost message.	Noted
Scottish Power	Both options presented within the change proposal represent an improvement on the baseline. Currently all scaling is	Noted

	<p>applied to the day/ red time band and as such may inflate the costs being incurred during this period.</p> <p>The change proposal therefore facilitates CDCM Objective (c) as it more accurately reflects the costs incurred, or reasonably expected to be incurred, by the DNO Party.</p>	
SP Distribution/SP Manweb	We believe that the proposal better facilitates both the DCUSA CDCM and general objectives.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	<p>Yes.</p> <p>Approval of this Proposal should improve the DNO's ability to meet obligations under CDCM Objective 3.</p>	Noted
SSE Energy Supply	<p>Yes.</p> <p>The proposal meets Objective 3 of the CDCM by producing more cost reflective prices.</p>	Noted
UKPN	Yes	Noted
Western Power	Yes, both options seem to better meet the CDCM objectives.	Noted
Question Four	Are there any alternative solutions or matters that should be considered by the Working Group?	
	Responses	Working Group Comments
British Gas	We do not think so. A benefit of both options, regardless of whether we agree with their principles, is that they are simple and transparent and so will be easily understood by customers. Any alternative solutions are likely to reduce the transparency and increase the complexity of the calculation.	Noted
GTC	<p>A paper on the scaling in the red period was submitted to MIG on the 14 November 2011. This set out some proposals and also provided a draft change proposal. We believe this should be considered as part of the working group's assessment.</p> <p>If option 2 is considered reasonable then we think it is equally justifiable to apply a scaler that applies only to the fixed scale</p>	The Working Group noted that the MIG paper formed the basis of DCP 123.

	<p>element. Why would this option be any more or less cost reflective.</p> <p>In carrying out the analysis the impact on IDNOs needs to be considered. If an options squeeze the margins available to IDNOs then it needs to be demonstrated why this is cost reflective.</p> <p>The development of option 2 appears to organise the principle of the CDCM methodology (schedule 16 of DCUSA, paragraphs 73 to 86). In these paragraphs the methodology explains that:</p> <ul style="list-style-type: none">• network costs associated with the lower network tiers are allocated to the standing charge components• “other expenditure allocated to the HV and LV network levels is included in the fixed charge.” <p>This being the case, then option 2 results in scaling costs being applied only to the higher network tiers. There is no evidence that the CDCM network model under recovers costs from the higher network tiers. We believe, intuitively, that unallocated revenues are much more likely to relate to customer costs at HV and LV.</p> <p>We believe option 2 will distort the cost reflectivity. We note the consultation refers to maintaining the “economic cost differential”. We believe that this can only be justified where it is reflective of costs. To maintain the differential for its own sake without any justification on how it makes charge more cost reflective could distort charges and be in breach of competition law.</p>	
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IPNL	<p>If we understand the effects of the proposal correctly then;</p> <ul style="list-style-type: none"> • for a DNO there will be no effect on the total amount of DUoS income received i.e. they will still get their regulatory allowance but will recover it in a slightly different way. • Less of this regulatory allowance will be recovered from day/red units and more will be recovered from night/amber units and particularly green units. • The options include varying assumptions on MPAN and capacity charges. <p>We would make the following observations;</p> <ul style="list-style-type: none"> • We do not consider that the case for justifying the proposed change has been adequately made. It is not in our view sufficient to say it is 'believed' that the current method is 'distorting' or that the red unit produced 'may be' excessive'. There needs to be quantification of these claims. • The illustrative tariffs provided in the RFI suggest that red unit rates will increase as a result of implementation of either option in several DNO areas rather than reduce so the issue is not just of charges that are too high but presumably also ones that are too low • Most IDNOs operate networks consisting of new housing developments so most of their DUOS income charges are derived from day unit charges (rate 1) and the residual from MPAN charges. We have analysed the impact on our total annual revenue at the portfolio level of options 1 and 2. Whereas option 1 is broadly neutral in its effects option 2 will REDUCE our annual income. Indeed 	<p>The Working Group agreed that margin squeeze is an important consideration.</p> <p>It was noted that there is a certain amount of margin that IDNOs receive and this has been validated by Ofgem, in approving the CDCM. The group noted that if the scaling solution reduces this margin Ofgem may not be able to approve the proposal.</p> <p>It was suggested that there is a fundamental problem in trying to calculate the IDNO discounts on a total cost basis rather than a tariff basis. It was noted that this sits outside the scope of DCP 123.</p>
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	<p>revenue from domestic unrestricted customers under Option 2 will be reduced by about 5%. We conclude that Option 2 is therefore not neutral in its effects on IDNO revenues.</p> <ul style="list-style-type: none"> • We believe the methodology as applied in Option 2 is producing anomalies; <p>a) in some areas import tariffs are returning negative values (LPN) i.e. customers will be paid to use the network not charged for it</p> <p>b) in some areas the green tariffs are higher than the amber tariffs (WPD S West)</p>	
Northern Powergrid	Consideration needs to be given to any knock-on impacts of the proposal. For example, the annual review pack will need to be updated to reflect any changes to the methodology.	Noted
Npower	No	Noted
Scottish Power	None that we are aware of.	Noted
SP Distribution/SP Manweb	None at this time.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	<p>N/A</p> <p>Adjusting the revenue matching mechanism appears to be the most efficient means of better achieving CDCM Objective 3.</p>	Noted
SSE Energy Supply	The proposal needs to avoid large changes to customer prices.	Noted
UKPN	No, we believe that there are two possible options for the revision of how scaling is applied within the CDCM, which is across all elements of the charge (option 1 of this DCP) or just across all unit rates (option 2), and do not believe that the working group should be looking at any further options at this time.	Noted

Western Power	No	
Question Five	Are you aware of any wider industry developments that may impact upon or be impacted by this CP? If so, please give details, and comment on whether the benefit of the change may outweigh the potential impact and whether the duration of the change is likely to be limited.	
	Responses	Working Group Comments
British Gas	<p>The are a number of current change proposals affecting CDCM charges:</p> <p>DCP 130 (removing the discrepancy between NHH and HH UMS)</p> <p>DCP 131 (15 months notice for distribution timebands)</p> <p>DCP 133 (500 MW common network model for CDCM input)</p> <p>DCP 125 (limiting changes to DUoS tariffs to 20% in one year)</p> <p>DCP 103 (DUoS charges for sub 100kW HH settled sites)</p> <p>DCP 136 (Notice Period for Asset Related Changes)</p> <p>Since this change proposal amends the method of scaling tariffs to match allowed revenue, it will have an interaction with all CDCM change proposals that affect the calculation of charges. It is important therefore that a method of scaling is adopted that is capable of being justified on its own merits on a stand alone basis and which will not need to be amended each time a CDCM change is implemented.</p>	The Working Group noted the DCPs listed by British Gas.
GTC	We believe further work is required to the CDCM to consider a more complete inclusion of the costs incurred in owning and operating a distribution system. For example:	The Working Group noted that there are costs not included in the CDCM but agreed that this is not a flaw in the model as the CDCM is an incremental cost model rather than a total cost model.

	<ul style="list-style-type: none"> The inclusion of replacement costs. The proper treatment of excavation and reinforcement costs. The appropriate asset life to be used (perhaps based on a weighted average of the life of DNO assets rather than assuming that they are all new with a finite life of 40 years). Treatment of customer costs that are not network related (i.e. they are driven by customer numbers rather than demand). 	It was noted that asset replacement is currently under consideration by the DCMF MIG.
IPNL	No	Noted
Northern Powergrid	No	Noted
Npower	No	Noted
Scottish Power	None that we are aware of.	Noted
SP Distribution/SP Manweb	No we are not aware of any wider industry developments that may impact upon or be impacted by this CP.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	The current MIG review of NHH / HH volumes and forecasts is lagging this Proposal. That proposal is being developed using current CDCM assumptions.	Noted
SSE Energy Supply	The impact on domestic customer prices should be considered in conjunction with the Retail Market Review proposals.	Noted
UKPN	There is currently an open action as part of the MIG to review the issue of the treatment of Asset Replacement within the CDCM. Although I understand MIG is awaiting on feedback from Ofgem on this matter, as this area was excluded as a cost input when the CDCM was being developed at the express instruction of Ofgem and is recovered as a component of scaling.	Noted
Western Power	This change proposal is specifically looking at the application	The Working Group agreed that there are a number of other

	of revenue matching (scaling). The amount of revenue matching required may be impacted on by other DCUSA working groups such as the 500MW group. This would in turn alter the impact of DCP123.	issues that may have a wider impact and noted that these will need to be considered by the group. It was also noted that DCP 123 will need to stand on its own merits.
Question Six	Are you supportive of the proposed implementation date of 1 April 2013?	
	Responses	Working Group Comments
The Working Group noted that with regards to the implementation date, the general consensus was that April 13 is the preferable date but if not this date then April 2014, rather than a mid-year change. It was noted that the impact on prices must be considered.		
British Gas	Yes – the current method of scaling in the CDCM is distorting the economic signals provided from the pre-scaled tariffs and is likely to be producing excessive charges in the red time band, it should be addressed as soon as practicable.	Noted
GTC	N/A	
IPNL	No.	Noted
Northern Powergrid	Yes	Noted
Npower	No Suppliers price customers on 1,2 and 3 year contracts any change to the CDCM can cause price shocks for consumers and windfall gains and losses for suppliers. Therefore in the interest of managing tariff volatility we request a minimum of 15 months notice of any change.	The group noted that this was a fair point, which it will need to give consideration to.
Scottish Power	We are supportive of the proposed implementation date of 1 April 2013. If this cannot be met we agree that the next implementation date should be 1 April 2014. We do not support a mid-year implementation date if the proposed date cannot be met as this will provide extra complexity in charges.	The Working Group agreed that that DCP 123 should not be implemented mid-year.
SP Distribution/SP Manweb	Yes we are supportive of the proposed implementation date.	Noted
Southern Electric Power Distribution and Scottish Hydro	Yes – notwithstanding the impact of the NHH / HH review referred to in our previous question response.	Noted

Electric Power Distraction.		
SSE Energy Supply	Yes, but every effort should be made to minimise the impact on price changes at that date.	Noted
UKPN	Yes, both options are an improvement on the current scaling option in our opinion and so the chosen option should replace the current solution at the first opportunity, which we would agree should be possible for 1 April 2013.	Noted
Western Power	Yes	Noted
Question Seven	Do you agree that both options put forward by the Working Group are better than the baseline?	
	Responses	Working Group Comments
British Gas	<p>Option 2 scaling (fixed p/kWh) is better than the baseline. We note that the working group has not identified any disadvantages with this option. Option 2 scaling:</p> <p>maintains the economic cost differentials between tariffs and voltage levels and therefore is better than the baseline which does not;</p> <p>will result in tariffs that are less volatile after any step change on implementation;</p> <p>is transparent and simple to understand;</p> <p>removes the potential for excessive tariff rates in any particular tariff rate;</p> <p>has previously been stated as a preferred scaling option by Ofgem; and,</p> <p>is based on principles that make it likely to be an enduring solution.</p> <p>It is not conclusive whether or not Option 1 scaling (%)</p>	Noted

	<p>multiplier) is better than the baseline. It is simpler to understand and more transparent than the baseline, but it is fundamentally flawed since it distorts the economic cost differentials within and between tariffs and voltage levels and so will not lead to efficient decisions by customers and therefore will not lead to the development of efficient and economical networks. Furthermore, we do not believe that having identified such a serious issue as potentially excessive charging in the red timeband, that an approach that only partially reduces such excessive charges (and has the potential to make them worse) should be implemented.</p>	
GTC	<p>We believe this consultation fails to demonstrate that the either option better meets the objectives:</p> <p>“That compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)</p> <p>That compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business”</p> <p>As a consequence we are unable to comment on whether either of these options is better than the current baseline. Also as proposer of DCP094 an DCP097 we note that Ofgem’s reasoning for rejecting these proposals was because of insufficient evidence to demonstrate that the change proposals better met the objectives. In respect of DCP094</p>	Noted

	<p>Ofgem commented:</p> <p>“The Workgroup have not provided sufficient evidence for the Authority to assess whether DCP094 will better facilitate the achievement of the Charging Objectives of the DCUSA”;</p> <p>and</p> <p>“In our view, the analysis and discussion carried out by the Workgroup has not been sufficient for us to reach a decision in respect of the relative cost reflectivity of charges under the current arrangements and under the proposal. The Authority may only approve a proposal to modify the CDCM if it is sure that the proposal will better achieve the Charging Objectives. We are in this case unable to say whether the modification better achieves the Charging Objectives and as such we are unable to direct the implementation of the proposal.”</p> <p>No. We support option 1 only. This is because that given an absence of an understanding of what costs the unrecovered revenue relates to it would be inappropriate to skew costs to one element or another.</p> <p>We see no cost based evidence to demonstrate that option 2 is better than the status quo in delivering charges that are cost reflective.</p> <p>No analysis has been undertaken as to whether either of the options distorts competition</p>	
IPNL	We do not think that a detailed rationale has been provided for the change so it is hard to say whether there is an improvement against the base line i.e. there is no quantification of ‘excessive’.	Noted
Northern Powergrid	Yes	Noted

Npower	Yes	Noted
Scottish Power	Yes, both options are an improvement on the current baseline.	Noted
SP Distribution/SP Manweb	Yes we agree that both options put forward by the Working Group are better than the baseline.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	Yes – both seem to provide reasonable solutions to perceived shortcomings in cost reflective pricing in the CDCM model.	Noted
SSE Energy Supply	Yes, apart from the large increases in some price components.	Noted
UKPN	Yes	Noted
Western Power	yes	Noted
Question Eight	Do you have a preference for Option 1 or Option 2? Please give supporting reasons.	
	Responses	Working Group Comments
British Gas	<p>Option 2 is our strong preference – we do not support option 1:</p> <p>As we point out above, Option 2 scaling maintains the economic cost differentials between tariffs and voltage levels. It will therefore provide users with the correct time of day cost signals and facilitate the development, maintenance and operation of efficient, co-ordinated, and economical distribution networks. Both the baseline and option 1 scaling distort the cost differentials between tariffs and voltage levels and are likely to lead to inefficient and uneconomical distribution networks. We note that Ofgem have previously stated that a p/kWh adder was a preferred option for the CDCM and that a fixed multiplier (option 1 scaling) would distort the cost signals that customers see.</p> <p>We also are not supportive of option 1 scaling because it will continue to produce charges in the red timeband that could</p>	<p>It was noted that figures provided by British Gas had been derived by taking the RFIs and calculating what the maximum impact of scaling was on each.</p> <p>It was noted that some of the numbers are very large, with Option 1 still putting a large amount of scaling onto the red timeband. The group noted that it was difficult to test whether it was an excessive amount.</p>

be deemed to be excessive. The figures below show the impact of scaling on the red timeband charges under the current method, under option 1 scaling and under option 2 scaling. Whilst option 1 scaling in most cases reduces the impact of scaling on the red timeband charge it can be seen that the impact of scaling on the red timeband is still large and could be deemed to be excessive in a number of DNO areas. Conversely, the impact on red timeband charges of option 2 scaling is much more benign in every instance.

Maximum impact of scaling on red time band tariffs			
DNO	Current (p/kWh)	Option 1 Scaling (p/kWh)	Option 2 Scaling (p/kWh)
UKPN-SPN	4.61	3.68	0.36
UKPN-LPN	-1.59	-1.36	-0.15
UKPN-EPN	-0.24	-0.21	-0.02
SPM	3.69	2.70	0.48
SPD	6.16	4.36	0.66
WPD-SWALEC	15.47	11.87	1.04
WPD-SWEB	25.61	17.21	1.04
WPD-WEST	6.33	4.27	0.33
WEPD-EAST	4.77	3.29	0.22
SHEPD	7.48	7.82	1.44
SEPD	9.41	5.46	0.59
NPG YORKSHIRE	8.42	5.72	0.58
NPG NORTHERN	11.07	4.80	0.78
ENW	6.88	5.04	0.39

GTC	Schedule 16 of DCUSA indicates that network costs of lower network tiers are funded through standing charges. To apply	Noted
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	<p>the scaling factor to unit charges only shifts the allocation of these costs to the kWh component shifts the allocation of these costs upstream.</p> <p>However, the costs are not identified as being solely related to upstream.</p>	
IPNL	We cannot support Option 2 – it is not revenue neutral on IDNOs and the illustrative tariffs, we believe, contain anomalies.	Noted
Northern Powergrid	<p>Yes Option 1 to take the pre-scaled tariff prices and then either raise or reduce each of these individual prices by the same percentage such that allowed income is achieved.</p> <p>We believe that this option preserves the pre-scaling relative differentials between unit rates and the fixed elements within tariffs. Because of the way that the revenue allowances are profiled throughout the price control review period the current method of revenue reconciliation distorts the underlying pre-scaled cost signal more and more each year as allowances increase (i.e. there is more scaling). The preferred option would maintain the underlying pre-scaled cost signals whatever the allowances.</p> <p>In addition this approach will potentially make the tariffs less volatile as it also has the added benefit of reducing the amount of revenue recovered from the unit element of the charges, which is most susceptible to environmental and economic influence. Hence it means that levels of under/over-recovery should be more predictable.</p> <p>This greater stability and predictability is a desirable outcome, especially given the number of recent change proposals the have been brought forward to try and improve the stability, transparency and predictability of the charges.</p>	Noted

Npower	Preference for option 1 as it would increase tariff stability by reducing the proportion of revenue recovered through consumption charges which are most susceptible to environmental and economic influence.	Noted
Scottish Power	<p>We prefer Option 2.</p> <p>The addition or subtraction of a fixed pence/ kWh amount across all unit rates (as opposed to just one particular time band) will reduce the possibility of under recovery and make tariffs less volatile.</p> <p>Applying a fixed adder across all unit rates, as opposed to only one, also gives customers more opportunity to influence their charges as they may be better placed to react to price signals at different points in the day.</p>	Noted
SP Distribution/SP Manweb	Our preference is Option 1 as it maintains the price message, is less volatile and more predictable.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	The fact that the Working Group did not determine any disadvantages arising from Option 2 suggests that it is preferable. The loss of the cost differential between tariffs and voltage levels (Option 1) may result in significant tariff disturbances in some DNO Areas in the first year of implementation.	Noted
SSE Energy Supply	<p>No, there is no clear choice between the two.</p> <p>Both options have their pros and cons. The increase in domestic standing charges under Option 1 is undesirable.</p>	Noted
UKPN	Although we believe that both options are an improvement over the current scaling solution, we note that as some of the revenue which is looking to be recovered through scaling relates to costs which are essentially fixed. Therefore a proportion of the scaling should be recovered through the	Noted

	fixed charge component and as such we believe that option 1 is the correct way to deal with scaling.	
Western Power	It is finely balanced. The first option should give more predictable revenue streams since fixed charges are also scaled; all things being equal this should imply less under/over recoveries from one year to the next and so would reduce price volatility. Option 2 would have more of an impact on high Red unit rates by spreading the scaling only over unit consumptions. On balance option 1 is likely to reduce price volatility going forward and so that is the preferred option.	The Working Group agreed that both options will reduce volatility but that option 1 will still have a significant proportion of scaling in the red time bands.
	It is the view of the Working Group that Option 1 maintains the relative differential between fixed and variable elements within a tariff, whereas option 2 maintains the differential between tariffs and voltage levels. Which differential do you think it important to maintain when scaling tariffs to allowed revenue? Please give supporting reasons.	
	Responses	Working Group Comments
British Gas	<p>As explained above, in scaling the cost reflective (pre-scaled) tariffs to recover allowed revenue, it is important to maintain the differential between tariffs and voltage levels. This preserves the cost reflectivity of tariffs and will facilitate the correct economic outcomes. Option 2 scaling delivers this.</p> <p>The working group have provided no rationale as to why maintaining the relative differential between fixed and variable elements within a tariff is desirable. We do not see this as desirable as it distorts the time of day cost signals contained in the pre-scaled tariffs and therefore will not facilitate economically efficient decision making by customers, leading to the development of inefficient and uneconomical distribution networks. This approach can also lead to potentially excessive charges in the red timeband.</p>	Noted
GTC	Preserving the economic cost differential between tariffs should only be	Noted
IPNL	N/A	
Northern Powergrid	We believe that maintaining the relative differential between	Noted

	<p>the charging elements and the pre-scaled allocation between customer groups is more important to maintain than the differential between tariffs.</p> <p>As stated above the approach will potentially make the tariffs less volatile as it also has the added benefit of reducing the amount of revenue recovered from the unit element of the charges, which is most susceptible to environmental and economic influence. Hence it means that levels of under/over-recovery should be more predictable.</p> <p>This greater stability and predictability is a desirable outcome, especially given the number of recent change proposals that have been submitted to try and improve the stability, transparency and predictability of the charges.</p>	
Npower	N/A	
Scottish Power	We believe it is more important to preserve the differential between tariffs and voltage levels, rather than the fixed and variable elements within a tariff. This maintains the reflection of costs incurred at the different voltage levels.	Noted
SP Distribution/SP Manweb	Maintaining the relative differential between fixed and variable elements, due to the increased predictability.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	Both should be considered important, as they determine, to a greater or lesser extent, year-on-year tariff volatility. The impacts of Options 1 and 2 would have to be modelled for our DNO Areas before a definitive preference can be expressed.	Noted
SSE Energy Supply	Both differentials are important.	Noted
UKPN	Both areas are important and should be maintained where possible, although using the current charging model it would not be possible to retain both through the modification of the arrangements for scaling. However we do strongly believe	Noted

	that any option for scaling should be looking to recover costs that would be expected to be picked up as part of the fixed charge, and thus should apply to both fixed and unit elements of the charge.	
Western Power	Either differential would seem appropriate.	Noted
Question 10	The elements included within scaling could be changed, however, the Working Group felt that this was outside of the scope of this CP but could be considered at a later date, under a different change proposal. Do you agree?	
	Responses	Working Group Comments
British Gas	<p>We believe this question is flawed. An important principle of scaling is that it does not contain any 'elements' but rather it simply seeks to scale charges to recover allowed revenue in a way that maintains or minimises the distortion of the cost signals between tariffs and voltage levels contained in the pre-scaled tariffs.</p> <p>It is important that scaling does not try to allocate costs as it will undoubtedly not allocate them in a cost reflective manner and so lead to final charges that are not cost reflective. Furthermore, any attempt to allocate costs using scaling is likely that mean that any future change to the cost allocation and modelling within the CDCM will also require consequential changes to the scaling approach. This is not appropriate – the method of scaling should be able to be justified on a stand alone basis.</p>	Noted
GTC	<p>We don't understand the question. One of the issues is that scaling that it is ill defined as to what "elements" or cost components the scaler seeks to recover.</p> <p>We believe a wider review of the CDCM is required to consider</p> <ul style="list-style-type: none"> • The inclusion of replacement costs • The proper treatment of excavation and 	Noted

	<p>reinforcement costs</p> <ul style="list-style-type: none"> The appropriate asset life to be used (perhaps based on a weighted average of the life of DNO assets rather than assuming that they are all new with a finite life of 40 years) Treatment of customer costs that are not network related (i.e. they are driven by customer numbers rather than demand). <p>However, we agree that is out of scope of this CP</p>	
IPNL	N/A	
Northern Powergrid	Yes	Noted
Npower	Yes	Noted
Scottish Power	We agree that the elements included within revenue scaling are outside the scope of this change.	Noted
SP Distribution/SP Manweb	Yes we agree, the MIG are reviewing the amount of scaling and whether replacement costs should be included.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	Yes	Noted
SSE Energy Supply	Yes.	Noted
UKPN	Yes, please see earlier comments in relation to Asset Replacement.	Noted
Western Power	Yes	Noted
Question 11	Do you have any further comments on DCP 123?	
	Responses	Working Group Comments
British Gas	The working group have not been able to identify any disadvantages with option 2 scaling and it seems clear to us that the advantages identified in option 2 scaling are more robust than those identified for option 1 scaling.	Noted

	As we explain above, option 1 scaling is fundamentally flawed and can still produce potentially excessive charges in the red timeband. We believe the workgroup should focus on the implementation of option 2 to expedite progress.	
GTC	N/A	
IPNL	N/A	
Northern Powergrid	Consideration needs to be given to any knock-on impacts of the proposal. For example, the annual review pack will need to be updated to reflect any changes to the methodology.	Noted
Npower	No	Noted
Scottish Power	No further comments.	Noted
SP Distribution/SP Manweb	No further comments.	Noted
Southern Electric Power Distribution and Scottish Hydro Electric Power Distribution.	No	Noted
SSE Energy Supply	The reduction of excessive peak unit rate charges for Half Hourly customers is desirable. However the accompanying disturbance to other price levels is unwelcome.	Noted
UKPN	No	Noted
Western Power	No	Noted