# DCP 443

## 'Excess Capacity'

## COLLATED CONCULTATION 02 RESPONSES WITH WORKING GROUP COMMENTS

| Company | Confidential/ Anonymous | 1. Option A – 12-Month Maximum Demand (MD) Approach<br><br>Is the 12-month excess capacity charge a strong enough price signal for Customers not to exceed their MIC? Please provide your rationale.? | Working Group Comments |
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| **British Gas**<br>[Supplier] | Non-Confidential | No comment. The input received did not assess whether a 12-month Maximum Demand approach would provide a sufficiently strong price signal. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | Yes, we consider that a 12-month excess capacity charge would provide a stronger price signal than the current arrangements and would encourage customers to review whether their agreed MIC remains appropriate.<br><br>However, we have concerns that the proposal may not sufficiently discourage persistent exceedance in all circumstances. Regarding example 5, where a customer regularly exceeds their MIC by the same level every month, the customer may simply treat the ongoing excess capacity charge as a normal cost of operation rather than seeking an increase in contracted capacity. In some circumstances, customers may have an incentive to optimise their charges by reducing MIC to access lower fixed charges, via a lower residual band, while continuing to exceed capacity. In these scenarios, the 12-month approach does not act as a disincentive to not exceed capacity. | Members discussed the risk of persistent exceedance and potential gaming following a reduction in MIC. It was clarified that reducing MIC would not automatically reduce the residual band, as a separate exceptional circumstances process would be required.<br><br>Members also noted that Option A did not introduce a differential between standard and excess capacity charge rates. A further suggestion was made to consider whether residual banding could reflect the higher of contracted capacity or actual demand; whether this fell within DCP 443 remained subject to further consideration. |

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| | | Similarly, in example 7, where a customer has recently reduced its MIC, a subsequent capacity exceedance could result in the customer operating at capacity levels similar to that used previously under a higher MIC, while potentially benefiting from lower fixed charges due to lower residual band, while still maintaining operation at their BAU capacity.<br><br>To address these potential gaming opportunities, consideration should be given to strengthening the incentive where repeated exceedances, or exceeding after reducing a MIC occurs, for example through a graduated multiplier or another mechanism that increases the cost of repeated or sustained exceedance. | |
| **NGED**<br>[DNO] | Non-Confidential | Yes. This option would provide an extreme price signal as customers would continue to face excess capacity charges based on their maximum demand over a 12-month period. The multiplier would be 12. This creates a greater incentive for customers to maintain an appropriate MIC and avoid exceeding their agreed capacity. However, the approach may increase operational complexity and be more difficult for customers to understand. | It was clarified that the identified complexity related both to implementation within the model and communicating the 12-month charging mechanism to Customers. Members noted that a similar approach had operated previously without apparent difficulties in Customer understanding. |
| **NPg**<br>[DNO] | Non-Confidential | No. We do not believe Option A is fit for purpose as it introduces a complex billing process that lacks transparency for customers. An invoice should continue to be on the basis of consumption data for the relevant billing period only. The inclusion of charges relating to units from a much earlier billing period will make invoices difficult to understand and frustrating to reconcile, as the price signal being | Members discussed the implications of erroneous peaks under the shorter MHHS correction window. It was noted that, unlike an in-month charge, Option A could continue to apply a charge arising from an erroneous peak |

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| | | sent will feel punitive by the time it is received (punitive as there is no recourse to correct; MHHS will reduce corrections to 4 months, so once the price signal is received the billing period will have been closed for 8 months). We do not agree with charging customers for breaches in MIC for extended periods after the breach.<br><br>We do not agree that Option A is a strong enough price signal. If a customer was to exceed their MIC once in the 12-month period there would be nothing incentivising them to increase their MIC/reduce their usage as they will be paying the excess charges regardless of future usage.<br><br>Also, it is unclear what would happen if a site had a peak which exceeded their MIC but this was later identified as a data error? Under MHHS we have a limited time to correct/backdate data, so if an error was identified outside of the new reconciliation periods we may not be able to correct the peak and the site would continue to receive the excess capacity charges for the 12-month period, even though the peak was due to a data error. | over the 12-month period after the settlement data could no longer be corrected. Members agreed that this issue required further consideration. |
| **SP ENW**<br>[DNO] | Non-Confidential | We do not consider it appropriate to consider the strength of price signals affecting customer behaviour directly as it is not an objective of the charging methodologies to do that, however, we do believe it is appropriate to consider cost reflectivity, which would in turn influence customer behaviour. | Noted. |

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| | | In the case of the 12-month MD Approach we cannot identify the cost reflective mechanism in this approach. We therefore do not believe it to be cost reflective. | |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | We do not consider that the options should be assessed primarily by reference to the strength of a behavioural price signal, as influencing customer behaviour is not itself an objective of the charging methodologies. The appropriate assessment is whether the charge is cost reflective, although a cost-reflective charge may in turn influence customer behaviour. For the 12-month maximum-demand approach, we cannot identify a clear cost-reflective mechanism linking a single exceedance to charges in subsequent months. We therefore do not consider Option A to be appropriately cost reflective. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We note that under this option, the standard capacity charge and 'exceeded capacity charge' remain the same but the customer's capacity charge would effectively be doubled for a year following each individual capacity breach.<br><br>Whether this is a sufficiently strong signal to deter capacity exceedance depends on how the per-annum cost of this option compares with the alternative, i.e. the customer paying for a capacity increase (which is one of the desired outcomes).<br><br>A request for a capacity increase would result in an increase in the customer's total standard capacity charge and, in some cases, in an | The request for further scenario analysis was noted for consideration when determining which options should be developed further. |

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| | | increase in their fixed charge, if the capacity increase moves the site to a higher residual band. This would vary on a case-by-case basis. One would anticipate that customers would want to limit any capacity increase to the upper boundary of their existing residual band. This may reduce but not always eliminate the customer's need to exceed their capacity.<br><br>Therefore, we would expect that Option A may provide a sufficient signal in some cases but not in others. We think some more analysis (in particular around different typical scenarios) would be helpful. Such analysis should also include a comparison with Options B and C. | |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | I think it could provide a strong enough price signal dependant on how far the capacity has been exceeded and how often the customer intends to exceed. I feel it would be a more effective method for stopping customers who rarely exceed (as it would punish them heavier by comparison) rather than those who consistently do. | It was noted that Option A could have a greater impact on infrequent exceeders than Customers who exceeded consistently. |
| **UKPN** [DNO] | Non-Confidential | Yes, prior to the introduction of the CDCM we used this approach and the volume of parties exceeding their agreed capacity was much lower than what we are seeing today. Having no real financial incentive results in some Customers not managing their connection and the associated capacity to the same degree that they would if | Members noted the previous use of a similar approach as a potential benefit, including evidence that it had operated previously and provided a stronger incentive to manage capacity. |

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| | | they faced a financial impact, we also feel that this approach is not only tried and tested (and worked previously) but is a fair and reasonable charge to levy where they do exceed.<br><br>The 12 month period aligns with the period during which changes of capacity may not be made following a previous change.<br><br>It is unclear why the working group considers this too complex for customers to understand. | The shorter window, strength of the price signal and cost reflectivity remained matters for further consideration. |
| Working Group Conclusions:<br>The Working Group considered that Option A could provide a stronger incentive to manage capacity but identified concerns around persistent exceedance, cost reflectivity, erroneous peaks under MHHS and implementation. These matters require further consideration. | | | |

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| Company | Confidential/ Anonymous | 2. Option B Differential Charge - Multiplier Approach<br><br>If this option was to be taken forwards, what do you believe the fixed multiplier should be in order to send a strong enough price signal for customers not to exceed their MIC? i.e. the excess capacity charge should be 1.5 times the capacity charge, 2 times the capacity charge etc? Please provide your rationale.? | Working Group Comments |

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| **British Gas**<br>[Supplier] | Non-Confidential | No comment. We do not have evidence from the analysis provided to support a specific fixed multiplier. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | If a fixed multiplier approach is adopted, we consider a multiplier of approximately 2 times the standard capacity charge should represent a reasonable starting point. This appears consistent with the indicative outputs from the Option C modelling.<br><br>In some cases however, depending on the residual and therefore region, when a site exceeds excessively, they may still be better off, even with a doubled excess capacity charge, to reduce their MIC and exceed compared to equivalent customers who are on a higher MIC and residual band but do not exceed.<br><br>A fixed multiplier may not be sufficiently cost reflective across all customer groups or charging regions. We would therefore welcome consideration of a scalable multiplier that increases as the level of exceedance increases. This may provides a stronger behavioural signal while also being cost reflective by improving the proportionality between the charge and the severity of the exceedance, and reduces the risk that customers viewing excess capacity charges as a cheaper alternative to agreeing the appropriate MIC. | Members discussed the suggestion of a scalable multiplier that increased with the magnitude of exceedance. It was clarified that this would involve increasing the rate applied as the level or proportion of exceedance increased, rather than simply reflecting the greater volume of excess capacity.<br><br>A mathematical approach was favoured over additional bands, while a frequency-based approach was considered potentially inconsistent with concerns raised about reliance on historical events. There was support for exploring a sliding-scale approach further, but no design was agreed. |
| **NGED**<br>[DNO] | Non-Confidential | A multiplier would provide a clear and simple price signal. However, NGED does not have a preferred multiplier value at this stage. Any multiplier selected should balance providing an effective incentive to avoid exceeding MIC while remaining proportionate and justifiable. | The concern that a fixed multiplier would be inherently subjective and not directly linked to network costs was noted as part of the wider cost- |

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| | | The key limitation of this approach is that the multiplier is inherently subjective and is not directly linked to underlying network costs. | reflectivity issue requiring further consideration. |
| **NPg**<br>[DNO] | Non-Confidential | We believe it would be more cost reflective for the CDCM to calculate a differential charge, however if a workable solution for Option C cannot be fully developed in this change then it seems reasonable to use a multiplier as an interim solution prior to wider review in the DUoS SCR.<br><br>As demonstrated by the working group RFI there was a consistent reduction in excess capacity when there was a clear cost signal provided to customers (i.e. higher excess rate to discourage exceedance). This cost signal was lost as an unintended consequence of other changes. We agree with the reintroduction of this cost signal in a way that returns status quo for those customer groups, without creating further unintended consequences for other customers.<br><br>The following table shows historic average differential (excess÷capacity rates) across all DNOs: | It was clarified that the previous differential referred to in the response had operated monthly and did not represent support for the 12-month approach.<br><br>Members also questioned whether a simple historic average was an appropriate basis for setting the multiplier and whether 1.5 would provide a sufficiently material signal. |

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| | | <table><tr><th>Charging Year</th><th>LV Site Specific</th><th>LV Sub Site Specific</th><th>HV Site Specific</th><th>All</th></tr><tr><td>2021/22</td><td>1.876</td><td>1.466</td><td>1.535</td><td>1.626</td></tr><tr><td>2022/23</td><td>1.874</td><td>1.457</td><td>1.520</td><td>1.617</td></tr><tr><td>2023/24</td><td>1.810</td><td>1.423</td><td>1.482</td><td>1.572</td></tr><tr><td>2024/25</td><td>1.817</td><td>1.428</td><td>1.492</td><td>1.579</td></tr></table><br>The proposed multiplier of 1.5 is broadly in line with the historic average for all three customer groups. Individual group averages were historically much higher for LV Site Specific at 1.8. | |
| **SP ENW** [DNO] | Non-Confidential | Again, we believe the appropriate lens to consider these options is cost reflectivity. As we cannot identify a cost reflective mechanism in this methodology we do not consider it to be appropriate. | Noted. |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | We do not support selecting a fixed multiplier solely to create a stronger behavioural signal. The appropriate lens is cost reflectivity. As Option B does not identify a cost-reflective basis for a particular multiplier, any value selected would be inherently arbitrary. We therefore do not consider Option B to be the preferred approach and do not propose a fixed multiplier. | Noted. |
| **SSE Energy Customer Solutions** | Non-Confidential | Similar to our response to q.1, we consider that the level at which the multiplier becomes a sufficiently strong signal to deter capacity | The request for scenario analysis was noted for consideration once the |

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| [Supplier / Generator] | | exceedance depends on how the per-annum cost of this option compares with the alternative.<br><br>This could vary both depending on the multiplier level, as well as on a case-by-case basis. Therefore, we would expect that a multiplier at level X (or Y or Z) may provide a sufficient signal in some cases but not in others. We think some scenario analysis would be helpful. Such analysis should also include a comparison with Options A and C (and their scenarios respectively). | Working Group had determined which approaches should be developed further. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | When reviewing our older CDCM models when there was still the distinction between regular and excess capacity charges the largest variance looked to be around 1.8 times so I think a level around that should be applicable now. | Noted. |
| **UKPN** [DNO] | Non-Confidential | Any charge other than that currently used (where exceeded capacity is charged the same as contracted capacity) would be an improvement, however we feel that if the approach is to use a multiplier, then having a reasonably material value is required, as a result we feel that 2 times the capacity charge would be appropriate, as this would likely ensure that Customers would notice the impact financially on exceeding the capacity as defined in their connection agreement. | Noted. |

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| | | Note that previously under CDCM we typically had excess capacity charges double those of the capacity charges in our regions. | |
| Working Group Conclusions:<br>The Working Group considered that a multiplier could provide a clear price signal but noted the difficulty of selecting an appropriate and cost-reflective value. A scalable multiplier warranted further consideration. | | | |

| Company | Confidential/ Anonymous | 3. Option C - Differential Charge – Model-Integrated Approach<br><br>This option is specifically designed to be cost reflective. In your view, does this approach achieve that? Please provide rationale. | Working Group Comments |
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| **British Gas**<br>[Supplier] | Non-Confidential | The model-integrated approach appears intended to be cost reflective and avoids applying an arbitrary multiplier. However, we are not yet satisfied that the worked example demonstrates a more cost-reflective outcome. The example shows a redistributive effect, with costs moving away from LV and HV half-hourly customers towards domestic and non-domestic aggregated tariffs, alongside an increase in generation credits. Further explanation and validation are therefore needed before this approach can be regarded as demonstrably cost reflective. | It was explained that the approach retained the CDCM's 500 MW modelling basis but adjusted volume forecasts to move costs towards the excess capacity charge. Some impact on other tariffs was considered inherent in the approach, although the impacts shown were considered relatively modest. |
| **ENC**<br>[IDNO] | Non-Confidential | We consider Option C has the greatest potential to deliver a cost-reflective solution because the differential is derived through the | It was noted that further model development, regional testing and |

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| | | charging model rather than through an arbitrary uplift. The approach is more closely aligned with CDCM principles and provides a stronger justification for the level of charge applied.<br><br>However, further analysis is required across multiple DNO areas before it can be concluded that the outputs are consistently cost reflective. The current modelling is based on a limited dataset and additional regional testing would improve confidence in the methodology and resulting charges. | specialist input would be required if Option C progressed. |
| **NGED**<br>[DNO] | Non-Confidential | Yes. This is method of calculating a multiplier however this may not be cost reflective. There is a possibility of double counting. | Members discussed the concern regarding redistribution and possible double counting. It was explained that the revised model reduced unit-volume forecasts to remove costs before reallocating them to excess capacity, rather than simply adding an amount to the excess capacity charge.<br><br>The clarification was acknowledged, although the wider concern regarding cost reflectivity remained relevant. |
| **NPg**<br>[DNO] | Non-Confidential | Not in its current form.<br><br>The model changes are impacting all tariff groups, so customers with a different charging structure (i.e. Domestic, Non-Domestic, UMS) | Members discussed the impact of the volume adjustment on other Customer groups. It was acknowledged that changing volume forecasts would inherently cause some movement |

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| | | are being impacted. This appears to be because the volume adjustment may be happening too soon in the model.<br><br>Table 104-B has adjusted volumes for the three core HH import customer groups only, so the model is working on the assumption that other customer groups are allocated comparatively higher volumes/allocation of assets by default. Hence all other customer groups are seeing an increase in charges, with generation seeing an increase in credits. LDNOs also see artificially larger discounts as their volumes are discounted after the adjustment.<br><br>There are increases in most if not all charging elements across all remaining customer groups (including Domestic), with some changes being significant (UMS unit rate 3). Generators are also receiving higher credits across all unit rates.<br><br>The approach has been explained in attachment 7 but it is not clear how the impacts to other customers is justified. | elsewhere in the model. Particularly large movements would require further examination, although no threshold for an acceptable impact was agreed. |
| **SP ENW**<br>[DNO] | Non-Confidential | This method uses the 500MW model to produce price signals consistent with that model. It is therefore as cost reflective as the current approach in calculating the scale of the charges. | Noted. |
| **SP Manweb Plc / SP Distribution Plc**<br>[DNO] | Non-Confidential | Yes. Option C uses the 500 MW model to derive the differential and therefore produces charging signals that are consistent with the existing CDCM modelling framework. On that basis, it is as cost reflective as the current approach used to calculate the scale of the | Noted. |

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| | | relevant charges, subject to the model assumptions being transparent and appropriately validated. | |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We have reviewed the example set out in Attachments 6 and 7 but we are not sufficiently expert in the CDCM to conclude whether the proposed approach results in cost-reflective 'Exceeded Capacity' charges or not. We'd appreciate a commentary from the DCUSA charging model contractors (CEPA/TNEI) or another suitable and neutral expert on the design of this solution. | The request for commentary from the charging model contractors or another suitable independent expert was noted. Specialist input would be required if Option C progressed. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | I believe it does succeed at being more cost reflective than the other 2 options as they had rather arbitrary increases (in relation to annual costs) whereas this method is formula driven from CDCM inputs.<br><br>Whilst I believe this method would do a good job of varying the standard and excess capacity charges, thus dissuading customers from exceeding, I'm still unsure how reflective of the actual costs the changes would be.<br><br>The method suggested does seem to create variance between capacity charges similar to what we see in older CDCM, this includes the variance being larger for LV than HV. | It was noted that achieving an exact cost-reflective value for the costs associated with excess capacity would be difficult. |

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| **UKPN**<br>[DNO] | Non-Confidential | This option would only be as cost reflective as the model produces cost reflective charges. When negative residual exists and Band 4 charges are lower than those for NFD is that cost reflective?<br><br>This would also vary across different DNOs, in that some may end up being broadly the same as the capacity charge whilst others could be well in excess of the capacity charge. We believe that to find an appropriate charge for exceeded capacity we need to utilise either data from the Customers usage (Option A) or a reasonable multiplier (Option B) rather than a modelled solution which we fear might not be cost reflective for all DNO regions. | A distinction was drawn between residual charges and forward-looking economic charges, with residual charges considered outside the scope of DCP 443. It was suggested that outcomes across DNO regions should be confirmed through further impact analysis, with specialist input, if Option C progressed. |
| Working Group Conclusions:<br>Option C was considered to have potential as a cost-reflective approach, but further modelling, regional testing and analysis of wider tariff impacts would be required before this could be established. | | | |

| Company | Confidential/ Anonymous | 4. Option C - Differential Charge – Model-Integrated Approach<br><br>Would this solution send a strong enough price signal for customers not to exceed their MIC? Please provide your rationale. | Working Group Comments |
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| **British Gas**<br>[Supplier] | Non-Confidential | The approach would create a differential between standard capacity and excess capacity charges, which should strengthen the price signal. However, the consultation material does not provide enough | It was noted that additional analysis would be required if Option C progressed to provide greater |

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| | | evidence for us to conclude whether the resulting signal would be sufficiently strong across customer groups. | evidence on the strength of the resulting signal. |
| **ENC**<br>[IDNO] | Non-Confidential | Regarding the modelling taken place so far for ENWL, we consider the model integrated approach is likely to provide a sufficiently strong price signal. The illustrative modelling indicates excess capacity charges are approximately 2 to 3 times greater than standard capacity charges, which appears material enough to influence customer behaviour and encourage customers to secure an appropriate MIC.<br><br>Unlike Option A, this approach also maintains a direct relationship between the charge and the period of exceedance rather than continuing charges beyond the period of exceedance. | Noted. |
| **NGED**<br>[DNO] | Non-Confidential | Yes. Introducing a differential between capacity and excess capacity charges would provide a clear incentive for customers to manage their capacity requirements appropriately. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | Yes, if calculated correctly. We agree with the working group assessment of the RFI, which shows a differential in capacity and excess capacity was previously effective and believe this would be effective again if reintroduced. | Noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | We believe it would send an appropriate cost reflective charge. | Noted. |

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| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | We believe Option C would produce an appropriate cost-reflective charge. We do not consider it necessary or appropriate to assess the option against a separate test of whether the charge is sufficiently strong to change customer behaviour. A charge derived consistently from the model should provide the appropriate signal arising from the identified network costs. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | As we've suggested in our responses about Options A and B, we would expect that all options may provide a sufficient signal in some cases but not in others. In order for us to be able to better assess signal strength and compare the three options in terms of their effectiveness,<br><br>• we would like to see some more analysis of each option using some typical scenarios; and<br><br>• such analysis should also include a comparison of all three options. | Members discussed using historical exceedance data to identify representative Customer types and behaviours and applying the three options to comparable examples. The analysis could compare the cost of exceeding with increasing MIC and any associated band change. It was agreed that existing analysis would first be identified, after which the Working Group would agree the scope of any further comparative scenario and impact analysis. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | Whilst the change in excess capacity will likely have an impact we think it is more likely the banding and residuals would play a larger impact on whether customers will adjust and /or exceed their MIC. | It was noted that residual banding could have a significant influence on Customer behaviour and that potential unintended consequences |

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| | | TCR queries are currently very prominent for us with customers looking to lower bands and charges. | would need to be kept under consideration. |
| **UKPN**<br>[DNO] | Non-Confidential | As per the response to Q3, we do not believe that it would produce a strong enough signal in all DNO regions. | The concern that Option C may not produce a sufficiently strong signal in every DNO region was noted as an issue requiring further analysis if the option progressed. |
| Working Group Conclusions:<br>The Working Group considered that further comparative analysis was required to assess the strength and consistency of the price signal across Customer types and DNO regions. | | | |

| Company | Confidential/ Anonymous | 5. Option C - Differential Charge – Model-Integrated Approach<br><br>Do you have any comments around this approach? Please provide rationale. | Working Group Comments |
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| **British Gas**<br>[Supplier] | Non-Confidential | We support the principle of pursuing a cost-reflective solution rather than an arbitrary adjustment. Our principal concern is the wider redistribution shown in the worked example. Excess-capacity revenue increases, but domestic and non-domestic aggregated customers also face higher charges, while LV and HV half-hourly charges reduce and generation credits increase. Although the percentage movements are relatively small, the scale and direction | It was acknowledged that the wider redistribution resulting from the modelling, including impacts on aggregated tariffs and generation credits, would require further analysis if Option C progressed. |

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| | | of the wider effects appear counter-intuitive and should be explained before the solution is progressed. | |
| **ENC**<br>[IDNO] | Non-Confidential | Please see our responses to question 3,4,6 and 7. | Noted. |
| **NGED**<br>[DNO] | Non-Confidential | It addresses the issue through the charging methodology rather than relying on an externally applied multiplier. However, it effectively achieves this through adjustments to the model's standing charge factors and unit rates, meaning it is primarily a redistribution of charges within the existing framework. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | We believe this would be the most suitable option if the calculation can be amended so that the impact on other customer groups is reduced. | Noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | How this method differs from the existing approach is by reflecting the costs in different charge elements. The first consultation provided some anecdotal evidence that excess capacity costs and the associated customer behaviour was different in character to normal network activity and so this may be appropriate although difficult to quantify. | Noted. |
| **SP Manweb Plc / SP Distribution Plc**<br>[DNO] | Non-Confidential | The principal difference from the existing approach is that Option C reflects the relevant costs through different charge elements within the model. The first consultation provided some anecdotal evidence that the costs associated with excess capacity, and the resulting customer behaviour, may differ in character from normal network | Noted. |

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| | | usage. Reflecting those costs separately may therefore be appropriate, although the distinction is inherently difficult to quantify on an integrated distribution network. The methodology and assumptions should be clearly documented and capable of independent replication. | |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | In the Attachment 6 example, we have noted that the proposed solution of reducing the unit volumes by a ratio which seeks to reflect estimated exceedance volumes results.<br><br>• in a small drop of the unit rates and fixed charges for site specific, banded tariffs, alongside a small increase in the standard capacity charges, and a material increase in the exceeded capacity charges (the latter as intended by this CP) by a factor of between 2.3 and 3.6 times,<br><br>But<br><br>• a small increase in the unit rates and fixed charges for users subject to both the domestic and the non-domestic aggregated tariffs. We note that customers on these tariffs are not subject to capacity charges, i.e. they are not part of the target group of the CP but they would be subject to an (albeit small) downside as a result of this of it.<br><br>We are not certain that the increase in aggregated tariffs can be justified and would like to see some analysis on this. Also, we could | Members agreed that the impacts on aggregated tariffs, which were outside the Customer groups directly subject to capacity charges, needed to be examined and properly documented. These effects would need to be explained whether Option C progressed or was ultimately discounted. |

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| | | not find this impact described in either the main consultation document or the Attachment 7 guidance. We think that **this omission needs to be rectified,** and all impacts need to fully be described in the next iteration of the CP documentation. | |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | N/A. | Noted. |
| **UKPN** [DNO] | Non-Confidential | Nothing further to what we have stated in response to Q3 and 4. | Noted. |
| Working Group Conclusions:<br>The wider redistribution arising from Option C, particularly impacts on aggregated tariffs and generation credits, requires further analysis and explanation if the option progresses. | | | |

| Company | Confidential/ Anonymous | 6. Option C - Differential Charge – Model-Integrated Approach<br><br>What are the potential benefits of calculating the differential excess capacity charge within the model rather than using a fixed multiplier (Option B)? | Working Group Comments |
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| **British Gas**<br>[Supplier] | Non-Confidential | The potential benefit of the model-integrated approach is that it could derive the differential through the charging methodology and therefore provide a stronger cost-reflective basis than a fixed multiplier. It may also avoid selecting an arbitrary multiplier. These benefits depend on the model producing outcomes that can be clearly explained and justified. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | The key benefit of calculating the differential within the CDCM model is improved cost reflectivity and stronger alignment with charging methodologies.<br><br>Additional benefits may include:<br><br>• Reduced reliance on an arbitrary multiplier.<br><br>• Greater defensibility from a regulatory perspective.<br><br>• The ability for the differential to reflect changes in underlying network costs over time.<br><br>• Reduced risk of over or under penalising customers in specific charging groups. | Noted. |
| **NGED**<br>[DNO] | Non-Confidential | Provides a more transparent methodology. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | Calculating differential excess in the model is more cost reflective than a fixed multiplier. | Noted. |

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| **SP ENW** [DNO] | Non-Confidential | This approach is truly cost reflective and mostly uses the existing model assumptions. | Noted. |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | The principal benefit is that the differential is derived within the existing model and is therefore grounded in the model's cost assumptions, rather than being set through an arbitrary fixed multiplier. This provides a more robust cost-reflective basis, makes greater use of the established CDCM framework and should improve consistency between the excess-capacity charge and the underlying charging methodology. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We appreciate that the intention of the Option C approach is to provide a less arbitrary and more cost-reflective solution but we are not able to say whether it does so. We'd appreciate a commentary from the DCUSA charging model contractors (CEPA/TNEI) or another suitable and neutral expert on the design of this solution. | The request for independent specialist commentary was noted, with specialist input expected if Option C progressed. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | Different DNOs and customers will have different situations, a formula based approach as opposed to a fixed multiplier would have more chance of applying appropriately to a wider range of circumstances. This should result in it being more cost reflective than a fixed multiplier would be. | Noted. |
| **UKPN** [DNO] | Non-Confidential | The only advantage of option C, over option B would be that it would be a charge calculated within the model itself rather than the | Noted. |

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| | | use of a multiplier, although for option B this would still need to be incorporated into the model to produce a full schedule of charges, as a result this is not a solution which we support at this time. | |
| Working Group Conclusions:<br>Cost reflectivity and transparency were identified as potential benefits of Option C, although further validation would be required before these benefits could be confirmed. | | | |

| Company | Confidential/ Anonymous | 7. Option C - Differential Charge – Model-Integrated Approach<br><br>Do you have any comments on how the model has been designed for this solution? Detail/guidance on the model and how it is intended to work can be found within attachment 7? | Working Group Comments |
|---|---|---|---|
| **British Gas** [Supplier] | Non-Confidential | The model design requires further scrutiny. In the worked example, excess-capacity revenue rises from approximately £1.6m to £4.7m, while domestic and non-domestic aggregated tariffs increase, LV and HV half-hourly tariffs reduce, and generation credits increase. In addition, the resulting HV excess-capacity charges appear significantly lower than LV charges despite higher underlying capacity costs for the HV group. We would welcome a clear explanation of these outcomes and further evidence that they are cost reflective rather than unintended modelling effects. | It was noted that the model would require further development and scrutiny if Option C progressed. |

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| **ENC**<br>[IDNO] | Non-Confidential | We welcome further clarification regarding the impacts on other charging components within the model.<br><br>In particular, we note that the illustrative modelling appears to reduce unit rates for site-specific customers whilst causing a slight increase in unit rates and fixed charges for aggregated customers. Additional explanation of the underlying cost drivers would be helpful to enable us to fully assess the impact of the proposal.<br><br>It would also be beneficial to understand whether similar outcomes are expected across other DNO regions or whether these impacts are specific to the ENWL model used for testing. | It was noted that further testing would be required to establish whether the observed impacts were specific to the model used for testing or would occur across other DNO regions. |
| **NGED**<br>[DNO] | Non-Confidential | The model appears to provide a proportionate and transparent mechanism for introducing a differential excess capacity charge while maintaining consistency with existing charging principles. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | The volume adjustment is sensible but in its current location it is impacting the charges of the remaining customer groups in an unintended way. | The concern regarding the location of the volume adjustment and its impact on other Customer groups was noted as an area requiring further examination. |
| **SP ENW**<br>[DNO] | Non-Confidential | While the modelling has naturally had to make some assumptions regarding the way costs are avoided by removing the excess capacity units from the 'normal' load, we believe overall it is an effective solution. | Noted. |

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| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | The model necessarily makes assumptions about how costs are avoided when excess-capacity units are removed from the 'normal' load. Given the integrated nature of distribution networks, some simplification is unavoidable. Subject to validation of those assumptions, we consider the proposed design to be an effective and proportionate solution. The final model and guidance should clearly explain the assumptions, demonstrate the resulting outputs across DNOs and tariff categories, and include appropriate change-control and assurance arrangements. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We have no comment but we'd appreciate a commentary from the DCUSA charging model contractors (CEPA/TNEI) or another suitable and neutral expert on the design of this solution. | The request for specialist commentary on the model design was noted. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | N/A. | Noted. |
| **UKPN** [DNO] | Non-Confidential | We are comfortable that the solution and the guidance sufficiently explain how the charge is calculated. | Noted. |
| Working Group Conclusions:<br>Further development and testing of the model would be required, particularly to understand the impacts across DNO regions and Customer groups and confirm that the model assumptions are appropriate. | | | |

| Company | Confidential/ Anonymous | 8. Is there another approach that could be taken that applies a differential to the excess capacity charge other than the two options (B and C)? Please provide details and any rationale. | Working Group Comments |
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| **British Gas** [Supplier] | Non-Confidential | No alternative differential approach is proposed at this stage. | Noted. |
| **ENC** [IDNO] | Non-Confidential | As noted in our response to Q2, a potential alternative could be a graduated differential where the excess capacity charge multiplier increases in line with the magnitude or frequency of exceedance.<br><br>Small exceedances could attract a lower differential while repeated or significant exceedances attract progressively higher charges. Such an approach may provide a stronger behavioural signal whilst retaining cost reflectivity. | The proposed graduated differential was considered potentially to be a variation of the multiplier approach rather than a separate option.<br><br>Members agreed that there was merit in considering the concept further, although no methodology was agreed. |
| **NGED** [DNO] | Non-Confidential | NGED has no alternative approach to propose at this stage. | Noted. |
| **NPg** [DNO] | Non-Confidential | None identified at this time. | Noted. |
| **SP ENW** [DNO] | Non-Confidential | We believe the only other approach would be to attempt to directly identify the excess capacity driven costs and add these to the model. Given the integrated nature of distribution networks, i.e. where loads are mixed together and use the same assets whether | It was acknowledged that directly identifying network costs caused by excess capacity represented a theoretical alternative, but that this |

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| | | produced as a result of excess capacity or not, we believe this would be very difficult to achieve. | would be difficult because demand is combined across shared network assets. |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | The main alternative would be to identify directly the network costs driven by excess capacity and add those costs to the model. In practice, this would be very difficult because distribution networks are integrated: loads are combined and generally use the same network assets whether or not part of the demand is above the agreed MIC. We therefore do not consider that a separate direct-cost approach would be proportionate or readily achievable. | It was acknowledged that directly identifying network costs caused by excess capacity represented a theoretical alternative, but that this would be difficult because demand is combined across shared network assets. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We have no other proposal. | Noted. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | Not that I am aware of. | Noted. |
| **UKPN** [DNO] | Non-Confidential | No, we believe that the working group has considered all possible options and the three presented are the only options available. | Noted. |
| Working Group Conclusions: | | | |

No separate alternative approach was identified for development. A graduated or scalable multiplier was considered worthy of further consideration as a potential variation of Option B.

| Company | Confidential/ Anonymous | 9. Which of the 3 options do you prefer? Please provide your rationale. | Working Group Comments |
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| **British Gas** [Supplier] | Non-Confidential | We do not have sufficient evidence to express a firm preference between the three options. Option C is attractive in principle because it seeks to be cost reflective rather than relying on an arbitrary multiplier, but the redistribution and tariff outcomes in the worked example need to be satisfactorily explained before we could support it. | Noted. |
| **ENC** [IDNO] | Non-Confidential | Our current preference is Option A and C.<br><br>Subject to further work to address the gaming risks identified, option A provides a strong behavioural signal, is relatively straightforward and aligns with the principle that customers should contract for the capacity they require. It also mirrors approaches previously used by some DNOs.<br><br>We also recognise that Option C has the potential to become the most cost-reflective solution. We would therefore support further development and testing of Option C. | Noted. |
| **NGED** | Non-Confidential | NGED's preferred option is Option B as it's easier to apply. | Noted. |

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| [DNO] | | It avoids the operational complexity associated with Option A. | |
| **NPg**<br>[DNO] | Non-Confidential | Option C if the volumes can be discounted in a more appropriate place to prevent unintended consequences to other customer groups.<br><br>If a solution for Option C cannot be developed then it seems reasonable to use a fixed multiplier as an interim solution prior to wider reform in the DUoS SCR.<br><br>We do not support Option A, due to the issues identified in our response to Q1 and Q10, as well as the reasons we provided in our response to the first consultation. | Noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | Option C. | Noted. |
| **SP Manweb Plc / SP Distribution Plc**<br>[DNO] | Non-Confidential | Option C. It provides the strongest link to the existing cost-reflective charging framework and avoids both the weak cost-reflective basis of the 12-month approach and the arbitrary multiplier required under Option B. It should therefore provide the most methodologically robust solution, subject to satisfactory model validation and documentation. | Noted. |
| **SSE Energy Customer Solutions**<br>[Supplier / Generator] | Non-Confidential | We feel that more analysis is required to enable a better comparison of the three options in terms of how well and how consistently they signal to the user that capacity exceedance should be avoided. | Noted. |

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| **SSE Energy Supply**<br>[Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN**<br>[DNO] | Non-Confidential | Option C seems the most likely to provide a deterrent whilst also being cost reflective. | Noted. |
| **UKPN**<br>[DNO] | Non-Confidential | We support option 1 as we feel that it reflects the usage which each customer has had on the network and applies a charge to them which is fair and reasonable based upon how they have exceeded their contracted capacity.<br><br>It is consistent with how they would have been treated had they properly applied for an increase. | Noted. |
| Working Group Conclusions:<br>All three options received some support. The Working Group did not select or discount an option at this stage and agreed that further analysis was required before determining which option(s) should progress. | | | |

| Company | Confidential/ Anonymous | 10. Are there any additional pros or cons that are not already listed in Table 1 for:<br><br>Option A<br>Option B<br>Option C<br><br>Please provide details. | Working Group Comments |
|---|---|---|---|
| **British Gas**<br>[Supplier] | Non-Confidential | For Option C, a potential advantage is the prospect of a methodology-based, cost-reflective differential. A potential disadvantage is its complexity and the risk of wider redistributive effects that may be difficult to explain to customers and may not be directly attributable to excess-capacity behaviour. No additional comments are offered on Options A or B. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | As outlined in our response to Q1, we consider a con for Option A is that there are potential gaming risks, such as a customer consistently exceeding every month or exceeding after reducing their MIC. | Noted. |
| **NGED**<br>[DNO] | Non-Confidential | Option A: Increased customer queries/disputes.<br><br>Option B: Multiplier may not be equally effective across all customer types. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | A – Yes, we believe the following are cons: | Members discussed the description of existing initial billing and credit-and- |

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| | | i. Reduced transparency in monthly invoicing, i.e. customer bill directly impacted by consumption data from 12 months prior. MHHS is shortening billing periods to 4 months so by the time the excess is queried it may be too late to correct.<br><br>ii. The calculation of excess capacity uses the reactive power units. Aging equipment behind the meter can unexpectedly create increased reactive power which can drive excess capacity. A customer may not be aware of the increase in reactive power until they receive a bill which flags that they have exceeded their MIC, at which time the excess can be flagged, investigated and mitigated (power factor correction equipment, maintenance etc). There may be a lag for customers to identify power factor issues if the excess in a given month is unclear because they are being charged for the excess from a previous month, which may have been driven by different factors (such as actual capacity exceedance in the active import reads). This could have negative consequences customers and can extend strain on electrical equipment behind and after the meter.<br><br>iii. The 12 month approach creates a new arbitrary billing period hidden within a monthly invoice. For site specific billing, DNOs have two monthly billing runs. The first is the initial billing, which issues a monthly invoice for each | rebill arrangements. It was clarified that credit-and-rebill was only undertaken following relevant data changes and that the description represented existing DUoS billing rather than a proposed implementation of Option A.<br><br>Members agreed that existing billing processes should not, in themselves, prevent future changes. The treatment of erroneous peaks under the shorter MHHS window was also revisited, but no change to the reconciliation arrangements was agreed. |

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| | | | relevant one month consumption period. The second is the credit and rebill run which corrects for any changes in the data received by the DNO. It does not seem appropriate to invoice monthly consumption data to customers in the initial billing run that is directly impacted by usage outside of that specific consumption period, however this would also be inappropriate to include in the credit and rebill run as it is not revised data. For example, a DNO will invoice the April billing period one month following in May. All data for the April invoice is based on that month's specific consumption data and relevant standing data. This is simple to explain and understand. The proposed approach would mean the April invoice is based on the same information, but also includes a potential extra charge from usage in an entirely different billing period. It is not clear who would be better served by this arrangement as it introduces complexity for all involved parties and is much more difficult for end customers to understand. The 12 month approach may have been used in the past but is arguably not fit for current and future markets, which have been moving towards tighter reconciliations and smarter billing. | |
| | | iv. | It is unclear how a peak that is later identified as an error would be treated, especially under the shorter MHHS timescale of 4 months to correct the data. The | |

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| | | customer may face higher charges for 12 months for a peak that was shown to be an error after the 4 months ended.<br><br>We have not identified any additional pros or cons for Option B or C. | |
| **SP ENW** [DNO] | Non-Confidential | None identified. | Noted. |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | No material additional advantages or disadvantages have been identified beyond those set out in the consultation and addressed in our responses. We would nevertheless emphasise that Option A introduces additional billing and data-management complexity, Option B relies on an arbitrary multiplier, and Option C depends on clearly documented and validated modelling assumptions. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | Not without the further analysis we have requested under some of the other questions. | Noted. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | No comment. | Noted. |
| **UKPN** | Non-Confidential | Not that we are aware of currently. | Noted. |

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| [DNO] | | | |
| Working Group Conclusions:<br>Additional issues were identified, particularly for Option A around billing transparency, erroneous peaks and the interaction with MHHS. These would be incorporated into the Working Group's assessment of the options. | | | |

| Company | Confidential/ Anonymous | 11. Are changes needed to any systems (such as the DNO billing system) for:<br><br>Option A<br>Option B<br>Option C<br><br>Please provide a summary of any system changes required for each solution, and what the timescales would be for these changes to be implemented. | Working Group Comments |
|---|---|---|---|
| **British Gas**<br>[Supplier] | Non-Confidential | No comment. The input received did not assess the detailed system changes or implementation timescales for the three options. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | We consider Option A would require a system change, but timings and scope of the changes are TBC. | Noted. |
| **NGED**<br>[DNO] | Non-Confidential | Option A: Likely to require significant billing system changes to support the tracking and application of maximum demand over a 12- | The response was noted as broadly consistent with the Working Group's |

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| | | month period. Expected implementation timescales are likely to be the longest of the three options.<br><br>Option B: Minimal system changes anticipated, primarily limited to tariff updates. Expected implementation timescales are likely to be relatively short.<br><br>Option C: Moderate changes may be required to charging models and associated processes. Expected implementation timescales are likely to be between those required for Options A and B. | previous assumptions that Option A would require the greatest system change, with Options B and C expected to require less significant changes. |
| **NPg**<br>[DNO] | Non-Confidential | We agree with the Working Group assessment that Option A would require system changes, the scope of which is not fully clear at this time.<br><br>We do not foresee system changes required to cater for Options B and C. | Noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | Option A may need changes to billing systems as it relies on a different application of the charge. Option B we expect would not although that will depend on the exact implementation. Option C would not require any changes. | Noted. |
| **SP Manweb Plc / SP Distribution Plc**<br>[DNO] | Non-Confidential | Option A may require changes to DNO billing systems because it changes the period over which the excess-capacity charge is applied and would require the relevant maximum demand to be retained and applied over 12 months. It may also require rules for MIC changes, changes of tenancy and corrected consumption data. | Members discussed how the 12-month charge might operate following a change of tenancy. It was noted that system requirements would depend on whether the charge continued |

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| | | Option B is not expected to require changes to core billing logic, although this depends on the final implementation and tariff setup. Option C is not expected to require changes to core billing systems because the output would be implemented through the normal tariff-production process. Any model and tariff-production changes should be capable of implementation within the normal charging timetable, subject to the final legal text and specification. | regardless of tenancy or ended when the tenant changed. Explicit rules would therefore be required covering changes of tenancy, MIC changes and corrected data if Option A progressed. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | As the question is directed at DNOs, we have no comment. | Noted. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | As the update would primarily just cause a movement on excess capacity charge we can't see a reason other systems would need to be adjusted. | Noted. |
| **UKPN** [DNO] | Non-Confidential | A change to the DNO billing system is likely to be necessary for option A as it would need to apply a charge for a period based upon each Customers usage. We do not believe that a change is necessary for options B and C as the system already includes a field for exceeded capacity charges, which will be calculated within the model. Consideration needs to also be given to the impact on IDNO billing system(s). | The need to consider IDNO billing systems as well as DNO systems was noted. |

Working Group Conclusions:

Option A was expected to require the greatest system change, while Options B and C were expected to require less significant changes. Further consideration would be required for tenancy changes, corrected data and IDNO systems.

| Company | Confidential/ Anonymous | 12. Are there any other points that you would like the Working Group to consider for any of the Options? Please provide details and your rationale? | Working Group Comments |
|---|---|---|---|
| **British Gas** [Supplier] | Non-Confidential | The Working Group should test and clearly explain the distributional impacts of Option C, including why charges increase for aggregated demand customers and generation credits increase while charges reduce for some of the customer groups directly subject to excess-capacity charging. It should also explain the relative LV and HV outcomes in the worked example. | The need to examine and explain the distributional impacts of Option C was noted as part of the further analysis required if the option progressed. |
| **ENC** [IDNO] | Non-Confidential | None that haven't already been identified. | Noted. |
| **NGED** [DNO] | Non-Confidential | No. | Noted. |
| **NPg** [DNO] | Non-Confidential | None at this time. | Noted. |
| **SP ENW** | Non-Confidential | None. | Noted. |

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| [DNO] | | | |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | No further points are identified. The Working Group should ensure that the final Option C methodology, model assumptions and implementation guidance are sufficiently clear for consistent application across DNOs. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | As we've suggested in our responses above, in order for us to be able to better assess signal strength and compare the three options in terms of their effectiveness,<br><br>• we would like to see some more analysis of each option using some typical scenarios; and<br><br>• such analysis should also include a comparison of all three options. | The request for comparative scenario analysis was noted. It was agreed that existing DCP 443 analysis and other relevant analysis should be brought together in a single location to support the Working Group's further review. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | The response had been omitted from the collated document during the main Working Group review and was therefore not substantively considered by the full Working Group at this meeting. It was agreed that the response would be added to the collation, recirculated and raised for comment at the next meeting. |
| **SSEN** | Non-Confidential | N/A. | Noted. |

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| [DNO] | | | |
| **UKPN**<br>[DNO] | Non-Confidential | Not that we are aware of currently. | Noted. |
| Working Group Conclusions:<br>Further comparative and distributional analysis were considered necessary. Existing DCP 443 analysis would be brought together to support the Working Group's further review. | | | |

| Company | Confidential/ Anonymous | 13. Do you believe it would be appropriate to treat revenue from excess capacity charges as either excluded revenue or additional revenue or otherwise excluded from recovered revenue. Please provide your rationale? | Working Group Comments |
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| **British Gas**<br>[Supplier] | Non-Confidential | No. Excess-capacity revenue has previously been forecast and recovered through the normal revenue-recovery arrangements. The evidence reviewed suggests that this revenue is capable of being forecast. Treating it outside normal revenue recovery would not appear cost reflective and could allow additional revenue to be retained outside the usual reconciliation arrangements. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | We consider that revenue from excess capacity charges should feed into allowed revenue and remain reflected within network charging models, as there are costs incurred when customers exceed their capacity, so an allowance should be made to recover these costs. | Noted. |

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| | | Furthermore, we cannot see how the revenue would otherwise be accounted for without it being a windfall, more precisely, if it is excluded revenue then there is the chance for the distributors to be making extra profit, if excess capacity charges aren't accounted for through the allowed revenue mechanism. Which would ultimately be against the interests of consumers, unless new conditions would be developed. | |
| **NGED**<br>[DNO] | Non-Confidential | No. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | No. The amount of revenue recovered for excess capacity charges makes up around 0.2% of total recovered revenue for NPg. Even if the forecast of excess capacity revenue was completely incorrect at the time of charge setting this would not have a significant impact on over- or under-recoveries.<br><br>We feel it is unnecessary to change the regulatory treatment of this portion of UoS revenue and that the changes necessary to the licence to facilitate this would be disproportionate to the issue and also may be out of scope of this change. | The relatively small proportion of recovered revenue represented by excess capacity was noted as relevant to the proportionality of making wider regulatory changes. |
| **SP ENW**<br>[DNO] | Non-Confidential | No, this is not appropriate and we think this should be discounted as an option. DNOs operate under a price control which counts all expenditure as totex, and produces a revenue target from that and other factors. If the spending on excess capacity cannot be | Noted. |

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| | | disaggregated from the allowed revenue target then it is not appropriate to treat the associated DUoS revenue separately either. | |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | No. DNOs operate under a price control in which expenditure is assessed as totex and translated, together with other price-control factors, into an allowed-revenue target. If expenditure associated with excess capacity cannot be separately and robustly disaggregated from the expenditure underpinning allowed revenue, it would not be appropriate to treat the related DUoS revenue separately. Doing so could result in inconsistent treatment of the associated costs and revenue and could create a risk of double recovery or an unintended financial benefit. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We consider that, in theory, network users shouldn't exceed their agreed capacity and should therefore not create a forecastable revenue stream from exceedance (or it should be zero). However, we acknowledge the reality that exceedance does happen and estimates of this can be produced based on past years. Also, we understand that excluding revenue derived from capacity exceedance from 'regular revenue' could require (disproportionate) additional changes which would sit outside of this CP. On the basis of these two reasons, we suspect that this is not a practical option. | Noted. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | No, at this stage we do not believe so as it is part of DUoS and seems inappropriate to remove only revenue related to excess capacity. | Noted. |

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| **UKPN**<br>[DNO] | Non-Confidential | Yes. This is revenue which is not reflective of the planned usage of the network, it reflects usage above and beyond what each Customer is contracted to use.<br><br>It is not a cost associated with providing the infrastructure that has been requested by the customer.<br><br>This usage has not been authorised and is unpredictable, potentially leading to under or over recoveries.<br><br>We believe that DUoS should recover the costs associated with running the network as designed. Excess capacity is not as designed or contracted and hence is not a lot different to theft in conveyance. As such a clear penalty should apply specifically to the customer exceeding capacity and the charges to other customers should not be made less cost reflective by adjusting them to compensate for this additional revenue stream. | The alternative view supporting separate treatment was acknowledged, including the distinction between contracted network use and uncontracted exceedance.<br><br>Members also noted the competing concerns raised by other respondents regarding revenue recovery, proportionality and potential double recovery. No change to revenue treatment was agreed. |
| Working Group Conclusions:<br><br>The majority of responses did not support separate treatment of excess capacity revenue. Concerns included proportionality, revenue recovery and the potential for double recovery. No change to revenue treatment was agreed. | | | |

| Company | Confidential/ Anonymous | 14. Can excess capacity revenue be considered excluded revenue or additional revenue or otherwise excluded from Recovered Revenue under the current Distribution Licence? Please provide your rationale and specify any relevant Licence Conditions? | Working Group Comments |
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| **British Gas** [Supplier] | Non-Confidential | We have not undertaken a legal assessment of whether the current Electricity Distribution Licence permits excess-capacity revenue to be treated as excluded or additional revenue. Our policy view is that it should remain within normal recovered-revenue arrangements. | Noted. |
| **ENC** [IDNO] | Non-Confidential | We are not aware of any existing provisions within the current Distribution Licence that would readily allow excess capacity revenues to be excluded from Recovered Revenue.<br><br>Excess capacity charges form part of distribution use of system charges and the revenues collected contribute towards a DNO's overall revenue recovery. As such, they would ordinarily be treated in the same manner as other DUoS revenues and therefore be subject to the established revenue recovery arrangements.<br><br>Whilst there may be policy arguments for treating excess capacity revenues differently, particularly given the difficulties associated with forecasting revenues arising from customer exceedance behaviour, we believe explicit licence modifications would be required before such revenues could be excluded from Recovered | Noted. |

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| | | Revenue or treated as a separate revenue stream in order to protect the customers against DNOs making additional profit from this. | |
| **NGED**<br>[DNO] | Non-Confidential | No. Excess capacity revenue is fully included within Recovered Revenue under the current Distribution Licence and cannot be treated as excluded or additional revenue. Any change to the Distribution Licence to exclude this revenue would be outside the scope of this DCP. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | No, we do not believe it can be considered as excluded or additional revenue under the current Distribution Licence.<br><br>The definition of Directly Remunerated Services (DRS) specifically states that it excludes Use of System charges.<br><br>9.7.7 The general principle is that a service provided by the licensee as part of the normal activities of its Distribution Business is to be treated as a Directly Remunerated Service if and to the extent that the service so provided is not already remunerated under any of the charges listed in paragraph 9.7.8.<br><br>9.7.8 The charges referred to in paragraph 9.7.7 are:<br>(a) Use of System Charges;<br><br>Further the definitions of the DRS categories (as listed in Appendix 1 to Special Condition 9.7) do not include anything that could be interpreted as relating to excess capacity. | The reference to the treatment of Use of System charges under the Directly Remunerated Services provisions was noted as supporting the view that an explicit licence change would be required. |

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| | | We are not familiar with any other licence conditions that would allow any other revenue to be excluded from Recovered Revenue under the current Electricity Distribution Licence. | |
| **SP ENW** [DNO] | Non-Confidential | No, the current licence has specific detailed conditions regarding the treatment of revenue. Excess capacity revenue cannot be considered to be excluded or additional revenue under those provisions. | Noted. |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | No. The current Electricity Distribution Licence contains detailed provisions governing the calculation and treatment of revenue. Excess-capacity DUoS revenue does not appear to fall within the existing categories of excluded or additional revenue and therefore cannot, under the current provisions, be removed from Recovered Revenue without an explicit licence change. This interpretation should be confirmed against the licence in force at the implementation date. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We cannot say. | Noted. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | No we do not believe so. | Noted. |

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| **UKPN**<br>[DNO] | Non-Confidential | We consider, if it is agreed that this should not be part of DUoS, that this could fall into the miscellaneous category of directly remunerated services as its the provision of a service for the specific benefit of a third party that has requested it (by their actions). | The alternative interpretation that a miscellaneous Directly Remunerated Services category could potentially apply was noted. The differing interpretations were not resolved, although the current view was that an explicit licence change would be required. |
| Working Group Conclusions:<br>The current view was that the current Distribution Licence would not readily allow excess capacity revenue to be excluded from Recovered Revenue and that an explicit licence change would be required. | | | |

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| Company | Confidential/ Anonymous | 15. **Question 15A** – If the answer to the above question was no, then what changes do you believe would need to be made to the current Electricity Distribution Licence to facilitate this?<br><br>**Question 15B**- Are there any other regulatory considerations that need to be taken into account in order to treat revenue from excess capacity charges in this way? Please provide details, including any processes that would need to be followed and any expected timescales for these processes? | Working Group Comments |

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| **British Gas**<br>[Supplier] | Non-Confidential | Question 15A: No comment on the specific licence drafting that would be required.<br><br>Question 15B: Any change would need to consider the effect on revenue recovery and customer charges. We do not support changing the treatment without a clear justification that it is cost reflective and consistent with the wider price-control framework. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | Q15A<br><br>If changes to licence arrangements were required, we would favour an approach whereby excess capacity revenues are not included within forecast revenue recovery calculations but are subsequently fed back into the allowed revenue reconciliation process. This would remove the need for DNOs to forecast unpredictable excess capacity revenues.<br><br>Q15B<br><br>Any proposed licence changes should ensure that excess capacity revenues continue to feed through the regulatory charging models and are not retained separately from the allowed revenue mechanism. Maintaining this link is important to protect the costumers and preserve transparency. | The suggestion that forecast treatment could be changed while actual revenue continued to feed into normal reconciliation arrangements was noted. |
| **NGED**<br>[DNO] | Non-Confidential | N/A. | Noted. |

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| **NPg**<br>[DNO] | Non-Confidential | If the revenue was to be treated as a DRS then either the fundamental definition of DRS would need to be altered to say that the excluded revenue portion of UoS charges could be considered as a DRS or the definition of UoS charges would need to be altered to say that the excess capacity charges is not a UoS charge. The latter of these could be a significant change to the Distribution Licence as it may need to be reflected in various places and the charge would need to be redefined as something else.<br><br>Additionally, a new category of DRS would need to be added to the Licence to allow excess capacity to be classified as a DRS. | The potential requirement to amend the Directly Remunerated Services provisions, the definition of Use of System charges, or introduce a new revenue category was noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | A: There are multiple options here. One would be an additional revenue category to be added to the licence to cover revenue raised directly from excess capacity charges. This revenue would need to cover the costs associated with excess capacity (including a share of central overheads) and a fair margin. Alternatively, a revenue reopener arrangement could flex revenue depending on DNO cost submissions.<br><br>B: The price control and associated financial model would need to be adjusted such that this revenue wasn't also recovered from other DUoS charges. This would include adjustments to regulatory accounting procedures so that excess capacity expenditure could be separately identified. | The identified regulatory options, including an additional revenue category or revenue adjustment mechanism, were noted. Any such approach would require the associated costs to be identified and would need to prevent duplicate recovery through other DUoS charges. |

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| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | 15A: Several mechanisms could be considered. One would be to introduce a specific additional-revenue category covering revenue raised directly from excess-capacity charges. This would require a robust basis for identifying the corresponding costs, including an appropriate share of central overheads and any permitted margin. An alternative could be a revenue reopener or adjustment mechanism linked to evidenced DNO costs. In either case, the licence would need to define the relevant revenue, its treatment in Recovered Revenue and the applicable reporting, reconciliation and assurance requirements.<br><br>15B: The price control and associated financial model would need to be amended so that the same costs were not also recovered through other DUoS charges. Regulatory accounting arrangements would also need to enable excess-capacity expenditure to be separately and consistently identified. The change would require Ofgem engagement, impact assessment, consultation and the applicable statutory licence-modification process, together with consequential changes to regulatory reporting and potentially the charging methodology. Given the fundamental nature of the change and the need for alignment with price-control arrangements, it is unlikely to be deliverable quickly and may need to be considered as part of a future price-control process. | Members noted the potentially extensive consequential changes, including amendments to the price control, financial model, regulatory accounting, reporting and assurance arrangements.<br><br>Regulatory engagement, impact assessment, Consultation and a licence modification process would also be required. Delivery was therefore considered unlikely to be quick and could require alignment with a future price control. |
| **SSE Energy Customer Solutions** | Non-Confidential | We cannot say. | Noted. |

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| [Supplier / Generator] | | | |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | N/A. | Noted. |
| **UKPN** [DNO] | Non-Confidential | Moving this out of DUoS would presumably need Ofgem agreement. Excess capacity charges may need to be dealt with outside of the CDCM/EDCM. | The need for regulatory agreement and the potential implications of dealing with excess capacity charges outside the existing charging methodologies were noted. |
| Working Group Conclusions:<br>Separate revenue treatment could require significant licence, price-control and regulatory changes. The Working Group noted that implementation was unlikely to be quick and could require alignment with a future price control. | | | |

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| Company | Confidential/ Anonymous | 16. Do you have concerns about revenue from excess capacity charges being considered as either excluded revenue or additional revenue or otherwise excluded from Recovered Revenue? Please provide details? | Working Group Comments |

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| **British Gas**<br>[Supplier] | Non-Confidential | Yes. Our concern is that excluding this revenue from normal recovered revenue could result in customers paying more overall and could weaken the normal reconciliation of forecast and actual distribution revenue. This is particularly difficult to justify where excess-capacity revenue appears reasonably forecastable. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | We would have concerns with any approach that permanently separates excess capacity revenues from the allowed revenue. Such an approach could weaken the link between charges collected and regulated revenue, potentially allowing revenues to be retained outside of normal reconciliation processes. | Noted. |
| **NGED**<br>[DNO] | Non-Confidential | Yes – it would introduce additional complexity and could create inconsistencies within the existing revenue recovery framework. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | Excess capacity only makes up around 0.2% of recovered revenue for NPg. This is not enough to drive any significant variance in over/under recovery, even if the forecast of excess capacity at the time of setting charges was to be completely wrong.<br><br>Treating this revenue as excluded or additional revenue adds complexity to the regulatory treatment of UoS charges and would require changes to the billing system that are not justified by the scale of the revenue suggested to be excluded and seem disproportionate to the perceived issue. | Noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | Yes, this is a fundamental rethink of the current regulatory arrangements and given the ED3 price control is close to conclusion, | Noted. |

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| | | it would likely be more than five years before such changes could be implemented. | |
| **SP Manweb Plc / SP Distribution Plc** [DNO] | Non-Confidential | Yes. This would represent a fundamental change to the current regulatory arrangements. Unless the associated expenditure can be separately identified and removed from the cost base supporting allowed revenue, excluding the related revenue from Recovered Revenue could create double recovery or an unintended windfall. It would also require changes to the price-control financial model, regulatory accounting and licence arrangements. Given the scale of those changes, implementation is likely to require a future price-control process rather than a short-term charging-methodology change. | Noted. |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | A mechanism to allocate any exceedance-related revenue would need to be developed. | Noted. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | It seems inappropriate to remove the revenue from excess capacity charges from the under/over recovery calculation due to the impact it could have. | Noted. |
| **UKPN** [DNO] | Non-Confidential | No, it makes sense. | Noted. |

Working Group Conclusions:

The Working Group noted concerns around additional complexity, reconciliation, potential double recovery and the scale of regulatory change required.

| Company | Confidential/ Anonymous | 17. What are the potential benefits of treating revenue from excess capacity charges as either excluded revenue or additional revenue or otherwise excluded from Recovered Revenue? | Working Group Comments |
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| **British Gas** [Supplier] | Non-Confidential | We have not identified a clear customer benefit. Although alternative treatment might strengthen the financial incentive for DNOs to manage excess-capacity charging, any such benefit would need to be demonstrated against the risk of over-recovery and higher charges for customers. | Noted. |
| **ENC** [IDNO] | Non-Confidential | We are concerned that any potential benefit should be achieved by modifying the forecasting treatment only, rather than removing excess capacity revenues from the allowed revenue altogether in the interest of our customers. Once actual revenues are known, these revenues should continue to feed into the normal process and be reflected within charging models. | Noted. |
| **NGED** [DNO] | Non-Confidential | None. | Noted. |

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| **NPg**<br>[DNO] | Non-Confidential | We do not believe there are benefits to this approach as it introduces the complexities identified in Q16 above and the level of excess capacity revenue is not sufficient for treating of the revenue as excluded to be beneficial. | Noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | It is unclear what the benefits of these arrangements would be. | Noted. |
| **SP Manweb Plc / SP Distribution Plc**<br>[DNO] | Non-Confidential | The potential benefits are unclear. In principle, separate treatment might improve transparency if both the revenue and the directly associated costs could be robustly identified. However, given the integrated nature of network expenditure and the existing totex price-control framework, we have not identified a clear benefit that would outweigh the additional complexity, regulatory change and risk of inconsistent cost and revenue treatment. | Noted. |
| **SSE Energy Customer Solutions**<br>[Supplier / Generator] | Non-Confidential | See our response to q.13. | Noted. |
| **SSE Energy Supply**<br>[Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN**<br>[DNO] | Non-Confidential | We are not sure of any direct benefits from treating excess capacity revenue separately. | Noted. |

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| **UKPN**<br>[DNO] | Non-Confidential | It removes an element of uncertainty from price setting and makes charges more cost reflective. | Noted. |
| Working Group Conclusions:<br>No clear benefit of separate revenue treatment was established that would outweigh the identified complexity and regulatory considerations. | | | |

| Company | Confidential/ Anonymous | 18. Do you have any other comments? | Working Group Comments |
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| **British Gas**<br>[Supplier] | Non-Confidential | Overall, we support the objective of providing an effective signal for customers to remain within their agreed capacity. However, the preferred solution should be demonstrably cost reflective, proportionate and capable of being clearly explained. Further assurance is needed on the wider charging impacts of Option C before a firm preference can be given. | Noted. |
| **ENC**<br>[IDNO] | Non-Confidential | We support the overall objective of restoring an incentive for customers to remain within their agreed MIC.<br><br>We encourage the Working Group to further explore amendments that address repeated capacity exceedance and potential gaming opportunities. We also believe that Option C warrants further development as it has the potential to provide the most cost reflective long-term solution. | Noted. |

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| | | Any solution should remain simple enough for customers and suppliers to understand whilst providing a clear and proportionate signal that encourages efficient use of network capacity. | |
| **NGED**<br>[DNO] | Non-Confidential | No. | Noted. |
| **NPg**<br>[DNO] | Non-Confidential | None at this time. | Noted. |
| **SP ENW**<br>[DNO] | Non-Confidential | None. | Noted. |
| **SP Manweb Plc / SP Distribution Plc**<br>[DNO] | Non-Confidential | Overall, we support Option C as the option most consistent with the cost-reflective principles of the existing charging methodology. We do not support separate treatment of excess-capacity revenue under the current price-control and licence framework.<br><br>We support retaining the flexibility provided under Clauses 12.3 to 12.5 of the DCUSA for managing Excess Capacity. Exceeding contracted capacity should not automatically result in a requirement to reduce import/export levels or disconnect, as this may not be operationally feasible for all customers and may be disproportionate in cases of temporary or isolated exceedances. However, it would be helpful to clarify how an exceedance is assessed, specifically whether this is based on a single point-in-time measurement or an average over a 30-minute settlement period. | Members subsequently clarified that DCP 443 was concerned with charging arrangements rather than changing or relaxing existing rights under the connection provisions. For billing purposes, the relevant data was understood to represent an average over the 30-minute settlement period rather than a single point-in-time measurement.<br><br>The proposed charging arrangements would therefore sit alongside the existing connection rights. |

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| | | We note that the existing provisions already provide a clear and proportionate framework for managing capacity exceedances. Customers are required to engage with the Company and either apply for a variation, explain why a variation is not appropriate, agree an alternative timescale, or move to an alternative contractual arrangement. This strikes an appropriate balance between managing network impacts and providing flexibility for customers.<br><br>While we believe flexibility should be retained, the framework must also protect compliant network users and consideration should be given to strengthening the remedies available to DNO's where customers repeatedly or over a sustained period exceed their contracted capacity. Where such behaviour results in additional network costs, operational restrictions or constraints, increased system and asset risk, or reinforcement requirements, those costs should, wherever reasonably practicable, be borne by the customer responsible rather than being socialised across the wider customer base. This approach would reinforce the principles of fairness, cost reflectivity, and efficient network utilisation, whilst recognising that some customers may have legitimate operational reasons for occasional or short-duration exceedances. | |
| **SSE Energy Customer Solutions** [Supplier / Generator] | Non-Confidential | We expect that further to paragraph 4.143 of this second consultation, a third consultation will likely be required to, amongst other things, consider draft legal text for the option(s) to be taken forward, and to consider an EDCM solution. | The expectation that a further Consultation may be required to consider draft legal text and an EDCM solution was noted as the respondent's expectation. No date or |

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| | | | commitment to issue a further Consultation was agreed at this meeting. |
| **SSE Energy Supply** [Supplier] | Non-Confidential | No comment. | Noted. |
| **SSEN** [DNO] | Non-Confidential | N/A. | Noted. |
| **UKPN** [DNO] | Non-Confidential | No not currently. | Noted. |
| Working Group Conclusions:<br>The Working Group noted that DCP 443 concerned charging arrangements rather than changing existing connection rights. Outstanding issues across the options would be considered further before determining which option(s) should progress. | | | |