DCP 461 Working Group Meeting 15

28 April 2026 at 13:00 - Web-Conference

Attendee	Company
Working Group Members	
Aishwarya Harsure [AH]	NESO
Alex Iknoic [AI]	Roadnight Taylor
Ben Godfrey [BG]	NGED
Brian Hoy [BH]	SP ENW
Claire Witty [CW]	SPEN
Ed Grimsey [EG]	BU-UK
Edda Dirks [ED]	SSE Generation
Helen Slack [HS]	Centrica
Jack Purchase [JP]	NGED
John Harmer [JH]	WatersWye
Liam Sweeney [LS]	Ofgem
Matthew Paige-Stimson [MPS]	National Grid
Natalija Zaiceva [NZ]	UKPN
Nikki Pillinger [NP]	Roadnight Taylor
Rohan Sachdev [RS]	SSEN
Lee Wells [LW]	NPg
Will Bowen [WB]	UKPN
Code Administrator	
Craig Booth [CB]	Secretariat
Richard Colwill [RC]	Chair

1. Administration

Recording

1.1 The Chair informed members that this Working Group meeting would be recorded. No members objected to this. The purpose of this recording is purely to aid the Technical Secretariat in producing an accurate report of the meeting.

Apologies

1.2 No apologies were received ahead of the meeting.

Competition Law Guidance and Terms of Reference

1.3 The Working Group reviewed the "Competition Law Guidance" and "Terms of Reference". All Working Group members agreed to be bound by the Competition Law Guidance for the duration of the meeting and agreed to the Terms of Reference.

2. Actions Updates

2.1 02/02 – The Chair confirmed that this action remains open as standing action, for attention post consultation 2.

2.2 12/01 – The Chair confirmed this would be reviewed as part of the section 8 review in the meeting. This action was closed.

2.3 12/02 – The Chair confirmed the no detriment legal text had been drafted and was to be reviewed in the meeting. This action was closed.

2.4 12/03 – The Chair confirmed the legal text was to be reviewed in the meeting and amended accordingly. This action was closed.

2.5 12/05 – The Chair confirmed the legal text had been consolidated. This action was closed.

2.6 12/06 – The Chair confirmed this would be reviewed as part of the section 8 review in the meeting. This action was closed.

2.7 12/07 – The Chair confirmed this would be reviewed as part of the section 8 review in the meeting. This action was closed.

2.8 14/01 – The Chair confirmed the details of the three new CPs and the agreed approach had been communicated to Ofgem. This action was closed.

2.9 14/02 – The Chair confirmed this would be reviewed as part of the section 8 review in the meeting. This action was closed.

2.10 14/03 – The Chair confirmed this would be reviewed as part of the section 8 review in the meeting. This action was closed.

2.11 14/04 – The Chair confirmed this would be reviewed as part of the section 8 review in the meeting. This action was closed.

2.12 14/05 – The Chair confirmed this would be reviewed as part of the section 8 review in the meeting. This action was closed.

2.13 14/06 – The Chair confirmed the assessment of the objectives of each of the three new CPs had been copied to the consultation. This action was closed.

2.14 14/07 – The Chair confirmed this would be reviewed in the meeting. This action was closed.

2.15 14/08 – The Chair confirmed the updated consultation and draft legal text documents had been circulated. This action was closed.

3. Purpose of the Meeting

3.1 The Chair advised that the purpose of the meeting was to review the draft consultation and draft legal text.

4. Review of the Draft Consultation

4.1 The Chair proposed to review section 8 of the draft consultation, to act as a refresher and to review amendments to that section, noting that the earlier sections had been reviewed and were based on the history of the CP.

4.2 ED suggested that paragraph 7.5 would act as a good lead-in to section 8, but that this should be amended to reflect the content in section 8. The Chair agreed that this should be amended in a future update.

Action 15/01	Chair/Working Group to update paragraph 7.5 once the structure and content of section have been finalised.

4.3 ED suggested a minor wording change to section 8.2, proposing to remove the word “wide” from the phrase describing the data analysis (“a wide range of historic transmission reinforcement cost data”), as this is subjective and not an accurate reflection of the size of the dataset.

4.4 ED suggested improving the Paragraph 8.3 by explicitly referencing the data sources, proposing wording along the lines of: “the working group analysed a range of historic transmission reinforcement costs provided by NESO and NGET”. The Chair agreed to make this amendment.

4.5 ED suggested adding a clear reference line to the graph, preceding paragraph 8.3, at the proposed threshold of 125,000 MW, to make it easier for readers to see exactly where on the curve the proposed threshold sits. The Chair agreed to make this amendment.

4.6 BH questioned describing the approach as “percentile-based”, explaining that the threshold was not deliberately set at a specific percentile (e.g., the 95th), but was identified by observing where the graph showed a clear change or jump. BH suggested rephrasing the question to be more general, rather than framing it as a percentile-based approach, to better reflect how the threshold was actually determined. The Chair agreed to make this amendment.

4.7 ED suggested a minor wording improvement: replacing the term “last man standing risk” with “last remaining customer risk”, noting this wording is already used elsewhere and is clearer. The Chair agreed to make this amendment.

Voltage-Based Options

4.8 ED questioned the inclusion of the voltage-based option, noting that other voltage-based options (1.3 and 2.3) had already been ruled out, therefore querying whether this should also be discounted on the same basis.

4.9 BH explained that this option is different from the previously discounted voltage-based options. He explained that these represent two alternative ways of implementing the same option, and no decision has yet been made on which is preferable. On that basis, he felt it was appropriate to keep both for consultation rather than discounting one at this stage.

4.10 ED asked for clarification on what the phrase “two-voltage rule in reverse” means, suggesting the explanation could be expanded.

4.11 BH explained that the idea relates to taking the lowest voltage level as the reference point (e.g., 132 kV at the primary interface). Under this approach, assets at that voltage and above (such as 132 kV connected into HV) would be exposed, while those below that level would not be. BH agreed to expand on this and provided the following text for inclusion in the consultation: “This uses a similar principle to the two-voltage rule but applied the other way such that only 132kV and EHV are exposed to the charges but voltages that are more than two voltage levels away are not.”

Cost Apportionment

4.12 NZ sought clarification on how costs are apportioned under options 2.1, 2.2 and 2.4. Referring to an example where a £60m GSP reinforcement cost is split, NZ asked whether the first triggering customer always pays a fixed amount (e.g., £15m) with the remainder recovered through wider charges, or whether costs would be re-apportioned if additional customers subsequently connect (i.e., whether this applies on a rolling basis).

4.13 BH explained that costs are not fixed at first connection. Instead, ECCR applies so that each subsequent customer pays their proportionate share. Using the example, if four customers of equal size connect, each would ultimately pay £15m. The costs are therefore apportioned in proportion to capacity as new customers connect, rather than being permanently socialised after the first trigger.

4.14 BG raised a question about whether it is necessary to explicitly address how impacts are allocated between demand and generation customers. He noted that, under the existing (BAU) processes, impacts on the transmission system from demand and generation are already considered together, with decisions made based on whichever trigger is most material or occurs first. BG suggested that rather than creating a new methodology to share costs between demand and generation, the change should simply state that the existing BAU approach will continue, using the most appropriate or first trigger to determine responsibility.

4.15 BH agreed that one way to handle the issue is to make clear that whichever side (demand or generation) triggers the reinforcement first bears the cost, with the other effectively free-riding. BH noted this approach should be made explicit in the intent and reflected clearly in the legal text. However, he acknowledged this is not a perfect solution, as the opposing type of connection could still benefit indirectly, and there are trade-offs to consider.

4.16 BG reinforced that the key objective is clarity: the proposal should explicitly state that it is not seeking to change the existing BAU approach or use this change to fix other potential issues.

4.17 BG agreed to provide some text for inclusion in the draft consultation and provided the following text: "There will be no change to the existing treatment of ECCR. Reinforcement charges for transmission reinforcement will be apportioned to either demand and/or generation customers depending on the agreed capacity released by the reinforcement works for demand and/or generation customers."

4.18 BH suggested that the description of option 2.1 around recovery of remaining costs via the wider DUoS charging base is broadly correct but needs clearer wording. Specifically, it should reflect that while costs may initially be recovered from the wider charging base, they would subsequently be apportioned to any additional customers that connect later. BH proposed clarifying that recovery is staged: initially wider socialisation, followed by allocation of an appropriate portion of costs to later connecting customers. The Chair amended this.

"Fixed" Costs

4.19 NZ asked a question in relation to the following paragraph:

> **Option 2.1 - Cost apportionment**
>
> 5.31 In this solution, a form of cost apportionment could be applied to any transmission costs so that connecting customers would only pay for a proportion of the costs. This would address both issues identified:
>
> 5.31.1 The costs would be fixed for the individual customers and would not change irrespective of the outcome of other customers contracts; and

4.20 NZ raised concerns about the use of the term "fixed" in relation to costs, explaining that "fixed" could be misleading, as costs are only indicative and forecast at the point of contract, not fully known. NZ suggested the intended meaning may instead be that customers' exposure is capped to the proportion of capacity they request (e.g., 20%), rather than costs being immutable.

4.21 NZ suggested that the current wording could be interpreted as customers receiving a firm offer (e.g., £15m) with no further liability, even if additional costs arise years after connection. She suggested either removing the term "fixed" or clarifying what is meant, as the current drafting is ambiguous and risks implying no future cost adjustments.

4.22 BH explained that this issue depends on the precise legal drafting and acknowledged that "fixed" could reasonably be interpreted in multiple ways. BH reiterated that the underlying principle is limiting customers' exposure to a proportion of costs and preventing them from bearing costs associated with other customers, rather than fixing the final outturn cost at contract signature.

4.23 NZ suggested that if the term “fixed” is retained, it should be clearly qualified, for example, by stating that costs are fixed only in proportion to the capacity requested in the customer’s application. This would clarify what “fixed” refers to and avoid misinterpretation. The Chair agreed to make this amendment.

Infrastructure Site Volumes

4.24 AH flagged an issue in the consultation document (Section 5.14) regarding the statement that 60% of GSPs are infrastructure. She noted that this figure is incorrectly attributed to NESO data. Instead, she believes it may have originated from NGESO/NG transmission-related communications to Ofgem in 2020 and 2022, as well as early working group discussions. AH suggested either removing the percentage altogether or clearly caveating it as an indicative figure from early discussions, to avoid confusion or misattribution of the source.

4.25 BG suggested removing the reference to NESO and instead attributing the figure to information provided by industry, to avoid confusion. AH agreed this would clarify the source. BG also noted that CMP 460 had attempted to obtain this dataset but had been unable to do so.

4.26 MPS added that the figure is a historic estimate originating from the 2020 tertiary connections open letter discussions with Ofgem and cautioned against focusing on a precise percentage. MPS highlighted that asset sharing evolves over time, making it inappropriate to treat the figure as fixed or definitive.

4.27 NZ agreed that additional context would be needed if the 60% figure were retained, noting that it appears time-specific (e.g., 2022) while the text refers to “currently represents”. NZ questioned whether the figure applies only to constructed sites or also to contracted but not yet built sites and said that without such clarity it is not meaningful.

4.28 BH argued that retaining the 60% figure is important context for consultees. He explained that its purpose is not precision, but to signal the scale (that infrastructure GSPs are not a small minority (e.g., 5%), but around half or more of cases.) This helps readers understand that when connecting at GSP level, there is roughly a coin-flip likelihood of encountering infrastructure versus a simple connection site.

4.29 BH noted that this context has been used in previous consultations and questioned why it is now considered sensitive, unless the underlying position has materially changed.

4.30 JH supported BG’s earlier point that the 60% figure lacks a robust evidence base. He noted that multiple parties have attempted to obtain reliable data on this issue but have been unable to do so, meaning the figure is effectively unsupported. While he observed that the number has appeared in previous consultations without challenge, he argued that if its basis has changed or is uncertain, this should be made explicit. If the figure is removed, he suggested the document should instead state that the Working Group sought to determine the figure but was unable to obtain definitive data, to be transparent with consultees.

4.31 BH suggested that if a cross-reference is being included, it could be handled more simply by adding a brief footnote noting the two categories, and removing the explanatory wording in brackets.

4.32 BG indicated that NGED publishes data on the split between infrastructure and collection assets and offered to produce a figure with a clear reference.

Action 15/02	BG to provide a figure and clarity on the source.

Support For Options/Better Facilitating DCUSA Objectives

4.33 BH queried whether the consultation should focus on which options best meet the relevant charging objectives and therefore have a credible chance of being approved by Ofgem.

4.34 The Chair noted that a consultation question already asks whether any options better facilitate the user charging objectives. He explained that consultation responses could justify narrowing the options taken forward (e.g., reducing from nine options to three options), based on industry preference or opposition. The Chair noted that, equally, if respondents support keeping all options, this evidence could be used in a future paper to the Panel to justify progressing them all as formal Change Proposals, demonstrating that industry valued having a fuller set of choices.

4.35 BH stated he favoured keeping things simple, suggesting a clear yes/no support table so responses can be easily counted and interpreted for the Panel.

4.36 The Chair agreed simplicity helps but suggested questions could remain separate, with a visual table added to help respondents answer key questions (e.g., on support and objectives).

4.37 BG proposed combining both approaches:

4.37.1 one column asking whether respondents support each option; and

4.37.2 a separate column asking which options better facilitate the charging objectives.

4.38 BH suggested this would allow evidence of both general support and relative preference.

4.39 The group agreed that clearer, more visual formats (such as tables) reduce ambiguity and make responses easier to analyse and use when narrowing down the options to take forward.

4.40 BH suggested using a structured response table that asks consultees to assess the relevant objectives against each of the nine options. He noted it might be tedious for respondents to complete, but would be much easier for the Working Group to analyse and compare. JP agreed with this.

4.41 The Chair agreed to review the format, potentially using a simple tick-box (e.g., support/prefer) plus commentary in a single, comparable table, so respondents still explain why an option does or doesn't better facilitate the objectives.

Action 15/02	Chair/Working Group to review the format of the response form.

5. Implementation Date

5.1 NZ queried why the no-detriment assessment table shows a specific proposed implementation date (1 April 2028, aligned to ED3) for option 3.1, but no dates for options 1 and 2.

5.2 BH explained that options 1 and 2 are intended to be implemented as soon as possible following Authority approval (i.e., effectively one month post-decision), to allow customers to benefit earlier through connections reform. By contrast, option 3.1 has a dependency on ED3, making the implementation date materially relevant only for that option.

6. CMP 460 Delays/Alignment

6.1 NZ stated that CMP 460 may become only an interim or temporary solution, given the wider charging reforms being considered by Ofgem. She noted that timelines now appear uncertain and may slip from an April 2027 implementation to April 2028, due to additional meetings and assessments.

6.2 NZ expressed concerns about the practical implications of implementing a temporary change, including revising charging appendices, impacts on DNO business plans, and managing financial flows if arrangements are later replaced by a different Ofgem driven solution. NZ suggested this could create a sense of uncertainty or "limbo," which is difficult to address given the lack of clarity on future reforms.

6.3 BH responded that while these concerns are valid, the Working Group cannot anticipate or manage Ofgem's future decisions. BH stated the Working Group can only progress the proposal and allow the Authority to approve, reject, or potentially defer decisions considering wider reform activity.

6.4 BG explained that the defect being addressed is specific to how distribution networks pass through attributable reinforcement costs to projects. He noted that if CMP 460 progresses and addresses this issue, it may remove the need for the solution being developed under DCP 461, but that does not mean the work is misaligned or redundant. BG suggested, instead, that the proposals have been designed to work in parallel, not as dependencies on one another.

6.5 BG acknowledged there is some sequencing between the changes, and that it would be ideal for them to align in timing but felt this is unlikely in practice. BG considered it unlikely that Ofgem would introduce an entirely new alternative solution within a relevant timescale.

6.6 ED suggested holding a joint workshop with CMP 460 to ensure everyone has a shared understanding of where each group is, and to help address the kinds of questions and uncertainties that had just been raised.

6.7 BH stated that CMP 460 is a separate modification with its own timeline and approach. He noted that while there is some overlap (particularly with option 1), options 2 and 3 differ significantly. He felt there is enough overlap in membership to keep both efforts aligned informally, and that the Working Group should focus on progressing the current work rather than pausing for a joint session, especially given the uncertainty over whether Ofgem might pursue a wider review (which, if it did, could simply lead to rejection of either/both changes).

7. Draft Legal Text

Option 1.1

7.1 JH questioned whether the term “mainly” needs qualification and whether it effectively means 51%.

7.2 BH explained the intent is not a marginal majority, but cases where a single customer is the dominant user of a new asset (e.g., 95%), even if they do not use 100% of capacity.

7.3 MPS stated that, in principle, distribution networks are meant to be shared, not point-to-point, and that this would therefore be a very narrow and exceptional circumstance.

7.4 BH clarified that the option is intended to cover situations where a single large customer (e.g., a major data centre) effectively triggers a new GSP that is designed for their use, with no meaningful spare capacity for others.

7.5 The legal text was amended to state the customer would be charged “if the transmission works are required exclusively for your use” instead of relying on the “wholly or mainly” wording.

Options 1.1 and 1.2 with Option 1.4

7.6 The Chair asked whether paragraph 1.17 from the later options (options 2.1 and 2.2 combined with 2.4) was the same for options 1.1 and 1.2. BH confirmed that it was. The Chair agreed to do this offline.

Action 15/03	Chair to draft legal text for options 1.1 and 1.2 when combined with option 1.4.

7.7 The Chair asked whether the £125,000 per MW suggested in the consultation should be reflected in that draft legal text. It was agreed that, for clarity, this should be.

Action 15/04	Chair to draft amend the legal text to state the £125,000 figure.

Option 2.1

7.8 BH raised concern that the current wording may not clearly reflect what triggered the reinforcement (e.g., demand vs generation).

7.9 BH considered whether the calculation should explicitly follow the party that caused the reinforcement. BH suggested that it may not be worth refining the legal drafting at this stage, given the uncertainty over support for the option. Instead, the issue may be better addressed after consultation, if stakeholders raise concerns and the proposal progresses further.

7.10 BG explained that the proposal is that transmission identifies the customers to whom the works are attributable. DNOs would then allocate and recover costs between those identified customers using existing processes, rather than defining a new detailed methodology in the legal text.

7.11 BH raised a scenario where a generator triggers a new GSP, and later demand (or another generator) connects, questioning whether later connections should pay.

7.12 BG indicated that this would depend on how the DNOs structure their connection offers:

7.12.1 If customers are explicitly identified, costs can be shared between them.

7.12.2 If no individual customers are identified, the costs would instead be recovered via annualised charges.

7.13 BH clarified the intended principle: if a customer triggers a new GSP, they initially pay only for the share of capacity they use (e.g., 25%), with later connecting customers paying their share when they connect. BH noted this does not work if customers do not connect simultaneously, highlighting a mismatch with current drafting.

7.14 BG explained two possible approaches:

7.14.1 Costs can be allocated to a defined tranche of identified customers, based on their share of agreed capacity.

7.14.2 Any excess or unidentified capacity could be held or socialised by the DNO until future customers connect.

7.15 BG stated this would require agreeing an appropriate denominator (total capacity) and handling remaining capacity separately.

7.16 BH suggested that this approach appears to imply different legal text from what has currently been drafted, suggesting a disconnect between intended cost-sharing behaviour and the existing drafting.

7.17 BG clarified that, to make the approach work, the full capacity (e.g., 100 units) must be explicitly defined in the contract returned from NESO.

7.18 BG agreed, noting that while there may be choices about how unrecovered capacity is paid for (e.g., upfront vs recovered over time/asset life), the key requirement is clarity on the denominator. Without a clearly defined total capacity, the intended proportionate cost-sharing mechanism cannot function properly.

7.19 MPS raised a question about later customers connecting after upgrade works are complete, where some costs may initially have been recovered through annual connection charges. MPS asked whether the mechanism should allow later users to pay their share of unused capacity, even though the works were triggered and delivered by earlier customers. For example, if a third customer later takes one-tenth of the available capacity, should they pay one-tenth of the upgrade costs, thereby reducing the burden previously socialised through charges.

7.20 BH confirmed this aligns with the intended approach. BH noted that the current drafting broadly already reflects this intent, as it mirrors the existing mechanism but adapted for transmission, rather than introducing a fundamentally new model.

7.21 The Chair asked whether any additional context needs to be added to the consultation text on this issue.

7.22 BH noted a potential unresolved issue where generation triggers reinforcement and demand connects later, but was unsure whether to try to resolve this now in legal drafting or consult and seek stakeholder views instead.

7.23 BG argued it is not necessarily an issue, provided the denominator (total capacity) is defined correctly. BG suggested that demand and generation capacities could be aggregated into a single total, though acknowledged this is not how it has traditionally worked, as capacity is usually allocated in one direction. BG stated that, in his view, this complexity does not need to be addressed in this CP.

7.24 MPS highlighted a potential over-recovery risk, where capacity costs could be charged beyond 100% if both generation and demand later pay for overlapping portions of the same works (e.g., 70% via generation and 60% via demand). MPS noted the need for some form of cap, so total recovery for the same assets does not exceed 100%.

7.25 BG responded that this is not easily fixed with simple drafting, as capacity release may relate to generation, demand, or both, and may need to be treated separately.

7.26 BH felt the issue was too complex to solve within the current drafting phase and questioned whether it was worth the effort without knowing whether the option will gain support.

7.27 MPS highlighted that only the incremental capacity above existing spare capacity is what actually drives reinforcement. For example, if a GSP has 50 MW headroom and a user requests 70 MW, the reinforcement is driven by 20 MW, not the full 70 MW.

7.28 MPS suggested that, logically, cost apportionment could be based on the incremental 20 MW, since no reinforcement would have been needed for a 50 MW request.

7.29 BH responded that, while not perfect, the existing methodology instead uses the gross requested capacity (70 MW) divided by the total new capacity created by the reinforcement. BH explained that this approach can create some anomalies, but it is consistent with current practice.

Exceeding Standard Requirements

7.30 MPS explained that exceptional or enhanced assets requested explicitly by a user (beyond standard requirements) should not be borne by consumers. In the transmission context, these are treated as “one-off works” and are fully and directly charged to the user who requested them.

7.31 MPS noted that, similarly, in the distribution world, such assets would never be recovered through DUoS.

7.32 BH confirmed that distribution already has provisions for enhanced or non-standard requirements, with customers paying the associated costs. It was noted that it may be necessary to extend or adapt existing distribution wording so it clearly covers transmission-level enhanced security or exceptional assets.

7.33 MPS flagged an important difference:

7.33.1 For transmission one-off works, the capital cost is recovered upfront; but

7.33.2 Ongoing maintenance for those assets is recovered via annual one-off asset maintenance charges paid to the DNO.

7.34 MPS explained, therefore, that while capital recovery is clear, consideration is needed on how ongoing maintenance charges for one-off transmission assets are recovered from users over time.

7.35 NZ asked how N-1/N-2 connection requests (e.g., multiple transformers) would be treated for charging purposes: Is the first transformer "standard", with additional transformers treated as exceptions, or are all treated the same?

7.36 MPS explained this depends on Security and Quality of Supply Standard (SQSS) requirements and P2 demand groupings, noting that:

7.36.1 resilience requirements differ between demand and generation; and

7.36.2 the required number of transformers (SGTs) is influenced by both transmission design and distribution interconnection.

7.37 For example, for an islanded data centre with no 132 kV interconnection, three SGTs might be standard under SQSS. If the customer then requests a fourth SGT, this would be above standard requirements and treated as one-off works, fully charged to the user.

7.38 BH considered whether the draft legal text provides sufficient flexibility to pass through charges for exceptional or enhanced assets, particularly in high-risk scenarios such as large data centres. BH stated that, in his view, the current wording is deliberately vague but adequate, giving enough leeway to reflect charges appropriately without over-engineering the text at this stage.

7.39 MPS suggested it might help to add a clarifying sentence (for avoidance of doubt), similar to existing charging statements, making clear that user-requested enhanced or special assets are fully charged to that user.

7.40 BH noted that:

7.40.1 similar wording already exists, but it is framed around distribution assets and would need adjustment for transmission contexts; and

7.40.2 while the wording is not perfect, it already gives the right to charge users for assets in excess of the minimum scheme.

7.41 BH suggested this may be good enough for now, with the option to refine or tidy the wording later if the modification is approved and real-world scenarios expose further issues.

No Detriment Approach

7.42 The Chair asked whether the no detriment approach was reflected in the draft legal text.

7.43 BH noted that:

7.43.1 the no-detriment principle is not explicitly stated but is implied through the overarching principles;

7.43.2 this is likely not an issue, as no-detriment generally biases towards not charging, and the new arrangements would adjust this where applicable; and

7.43.3 overall, the options should remain compliant whichever route is approved, even without explicit wording.

7.44 The Chair highlighted that the main implementation issue concerns existing customers, rather than new ones.

7.45 BH agreed and noted that, if Ofgem endorses the approach, this would allow a clear implementation (go-live) date to be set. From that point, the revised charging approach could be applied prospectively, including to work-in-progress projects that move beyond go-live.

8. Consultation Timeline

8.1 The Chair confirmed both a tracked-changes version and a clean version will be produced, and circulated for comments, aiming to do so by end of Thursday 30 April 2026.

8.2 Subject to comments, the consultation will be issued on Friday 1 May 2026.

8.3 The closing date will therefore be 27 May 2026, and the collated comments and analysis will be circulated shortly after this date.

9. Next Meeting

9.1 The next meeting will be held on 18 June 2026 at 1:00pm.

10. Any Other Business

10.1 No other business was raised.

New and Open Actions

Action Ref.	Action	Owner	Update
02/02	MA, BH and BG to pull together work done by previous ENA group to see if it can be used by the Working Group.	Mark/Brian/Ben	On Hold (Post-Consultation 2) *Members agreed to keep this action open as it is not required to consult, but may be required for an Impact Assessment, following the Consultation.*
15/01	Chair/Working Group to update paragraph 7.5 once the structure and content of section have been finalised.	Chair/Working Group	To be closed *The Chair updated this paragraph post-meeting and issued this for review.*
15/02	BG to provide a figure and clarity on the source.	Ben	To be closed *This was provided post-meeting and included in the consultation document.*
15/03	Chair to draft legal text for options 1.1 and 1.2 when combined with option 1.4.	Chair	To be closed *The Chair drafted these post-meeting and issued them for review.*

Action Ref.	Action	Owner	Update
15/04	Chair to draft amend the legal text to state the £125,000 figure.	Chair	To be closed *The Chair updated this post-meeting and issued the legal text for review.*

Closed Actions

Action Ref.			Update
10/03	BH, BG & LW to draft the 3 new CPs (BH – option 1, BG - option 2, LW – option 3) to review at the January DCUSA Panel.	Brian / Ben / Lee	Closed
12/04	AH to check with their internal securities team to see if it is possible to gather a data set that provides connection scheme costs for DNOs.	Aishwarya	Closed
12/08	Working Group members to review the draft Consultation 2 document offline and provide any feedback/comments prior to the next meeting.	Working Group	Closed
13/01	The Secretariat to issue a meeting poll to the Working Group for the next meeting.	Secretariat	Closed
13/02	AH to include notes on the NESO dataset tabs to clarify what the data is based on.	Aishwarya	Closed
13/03	The Secretariat to issue updated NESO dataset, Consultation 2 and no detriment documents to the Working Group for review offline.	Secretariat	Closed
13/04	The Secretariat to issue a meeting poll to the Working Group for the next meeting.	Secretariat	Closed
12/01	The Working Group to cross-check the draft legal text (specifically for Option 2) to seek whether it addresses double cost-apportioning the charge.	Working Group	Closed

Action Ref.			Update
12/02	BH to draft the no detriment approach provisions within the draft legal text options offline for the Working Group to review.	Brian	Closed
12/03	The Working Group to review the draft legal text to establish whether additional wording is needed to allow for the ability to recover exceptional charges and whether it was requested by the Customer or not.	Working Group	Closed
12/05	The Secretariat to draft the legal text for all options to show only the relevant changed extracts.	Secretariat	Closed
12/06	DJ to provide an explanation in relation to ECCR impacts for paragraph 8.40 of the Consultation 2 document.	Drew	Closed
12/07	BH to draft wording within the Consultation 2 document to explain the ECCR assumptions in relation to option 2.1.	Brian	Closed
14/01	LW to speak internally and provide an update to the relevant colleagues around the details of this CP and the 3 new CPs.	Liam Sweeney	Closed
14/02	The Secretariat to ensure the NESO dataset is clearly articulated within the Consultation 2 document.	Secretariat	Closed
14/03	WB to draft high-cost project threshold examples for the Working Group to review.	Will Bowen	Closed
14/04	The Secretariat / Working Group to articulate discussions around a single transformer within the Change Report.	Secretariat / Working Group	Closed

Action Ref.			Update
14/05	The Secretariat / Working Group to add introductory wording in relation to the No Detriment Assessment Table within the Consultation document.	Secretariat / Working Group	Closed
14/06	The Secretariat lift the assessed DCUSA Charging Objectives from the 3 new CPs and include these within the Consultation 2 document.	Secretariat	Closed
14/07	The Secretariat / Working Group to add further context within paragraph 11.2 of the Consultation 2 document in relation to consumer impacts.	Secretariat / Working Group	Closed
14/08	The Secretariat to make the necessary updates to the Consultation 2 document and draft legal texts and circulate to the Working Group for an offline review.	Secretariat	Closed