




DCUSA Consultation 1		At what stage is this document in the process?
<h1>DCP 461</h1> <h2>Reducing the impact of Transmission Distribution Charges</h2> <p><b>Date Raised:</b> 13 August 2025</p> <p><b>Proposer Name:</b> Ben Godfrey</p> <p><b>Company Name:</b> National Grid Electricity Distribution</p> <p><b>Party Category:</b> DNO</p>		01 – Change Proposal
		02 – Consultation
		03 – Change Report
		04 – Change Declaration
<p><b>Purpose of Change Proposal</b></p> <p>To address a growing set of structural, economic, and policy misalignments that are actively hindering the UK's energy transition.</p>		
	<p>This document is a Consultation issued to DCUSA Parties and any other interested Parties in accordance with Clause 11.14 of the DCUSA, seeking industry views on this Change Proposal ("CP"). This is the first of two consultations.</p> <p>The Working Group recommends that this CP should proceed to Consultation.</p> <p>Parties are invited to consider the questions set in section 10 and submit comments using the form attached as Attachment 2 to <a href="mailto:dcusa@electralink.co.uk">dcusa@electralink.co.uk</a> by 28 November 2025.</p>	
	<p><b>Impacted Parties</b></p> <p>DNOs, IDNOs, Suppliers and CVA Registrants</p>	
	<p><b>Impacted Clauses</b></p> <p>Schedule 22 (other schedules to be identified during the development of the solution)</p>	

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Any questions?

Contact

Code Administrator

[dcusa@electralink.co.uk](mailto:dcusa@electralink.co.uk)

0207 432 3011

Proposer

Ben Godfrey

[bgodfrey@nationalgrid.co.uk](mailto:bgodfrey@nationalgrid.co.uk)

Activity

Date

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13 August 2025

First Consultation Issued

6 November 2025

Second Consultation Issued

December 2025

Change Report Approved by Panel

18 February 2026

Change Report issued for Voting

19 February 2026

Party Voting Closes

12 March 2026

Change Declaration Issued to Parties

17 March 2026

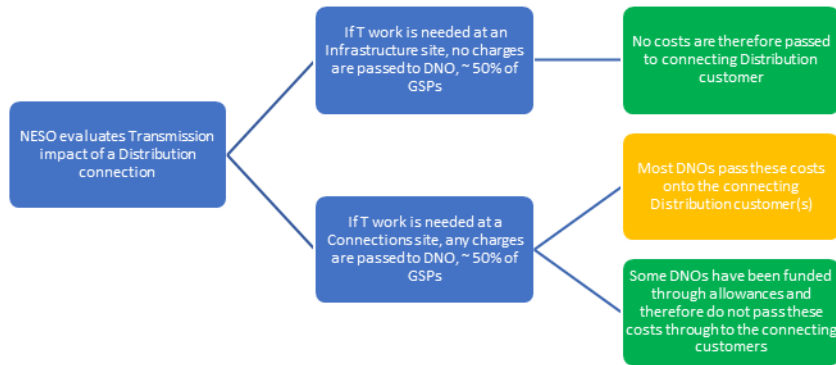
## 1 Summary

### What?

- 1.1 The current regulatory framework for transmission boundary reinforcement charges can create a significant barrier to the timely and cost-effective connection of new generation and demand customers. Under existing arrangements, most Distribution Network Operators (“DNOs”) are generally not explicitly funded to cover the costs of transmission reinforcement works triggered by customer connections at connection asset Grid Supply Points (“GSPs”). As a result, these costs are generally passed directly and fully to the initiating customer, often requiring substantial upfront capital contributions. However, this is not the case in all instances as the classification of a particular GSP can result in no charges being passed to the DNO. This results in inconsistencies between whether a connection customer is at risk for charges or not.

### Why?

- 1.2 The current approach to charging for transmission reinforcement results in different charging outcomes depending on the classification of transmission assets at a GSP in accordance with the Connection and Use of System Code (“CUSC”) charging methodology. For simplicity, if transmission assets at the GSP are (or will) be shared, i.e. utilised by more than one party, this is referred to as an ‘Infrastructure Site’, and any costs of upgrades of any shared transmission assets at the existing GSP or shared transmission assets at new GSPs are not passed on to the DNO, therefore any distribution connecting customer is not exposed to these costs. However, if the transmission assets needed by the DNO at a GSP are not shared, then the costs of those transmission assets are passed onto the DNO and this is referred to as a Connection Site.
- 1.3 Where transmission assets are not shared, there are different approaches on treatment of these costs across DNOs but generally, the DNO will then pass these costs onto the distribution connecting customer or customers. This can place an unsustainable financial burden on individual customers, such as those seeking to connect low-carbon generation or large-scale demand. In this situation, these customers would be required to fully fund transmission upgrades upfront. This may create a high-risk environment that deters investment, stalls projects, and leads to inefficient utilisation of the network. The Proposer argues that reform is essential to enable strategic, coordinated investment in the grid, support decarbonisation, and ensure that the costs of enabling infrastructure are shared appropriately across beneficiaries.
- 1.4 These differences in terms of connection cost recovery are shown in the diagram below and further described in the Working Group Assessment.



## How?

- 1.5 The variation in cost recovery approach is creating confusion and different outcomes for customers. Options should be considered to improve the customer experience, being cognisant of timescales to implement, standardisation across regions and voltage levels, impact of current/future price controls, impact on developer investment confidence, and the impact on the generality of customers.
- 1.6 Previously completed work had developed numerous options to be considered by any change proposals/modifications raised:
  - fully socialise via DUoS (“Distribution Use of System charges”), with or without a High Cost Cap;
  - fully socialise via TNUoS (“Transmission Network Use of System Charges”);
  - MW (“megawatt”) minimum threshold and ‘Standard Rate’ above that threshold;
  - customer apportioned costs with unallocated capacity socialised by DUoS; and
  - stronger and more consistent guidance for customers.
- 1.7 The Working Group considered that fully socialising through TNUoS is out of scope of this CP, as it would require progression through a CUSC modification, and that the Standard Rate above would not be cost reflective. As such, these options were not progressed by the Working Group.
- 1.8 Due to the potential impact on both the DCUSA and CUSC, parallel code modifications were considered by the Working Group, however the Working Group agreed to progress this CP at pace to provide a solution in time for ED3 (the third electricity distribution price control period that commences on 1 April 2028).

## 2 Governance

- 2.1 This CP is likely to impact competition in the distribution and transmission of electricity and will impact on the charges faced by both (i) a customer requesting a new/modified connection, such as those seeking to connect low-carbon generation or large-scale demand, and (ii) the generality of customers through increased DUoS charges. This CP has therefore been raised as a Part 1 Matter, and the solutions will be submitted to the Authority for a decision.

### 3 Why Change?

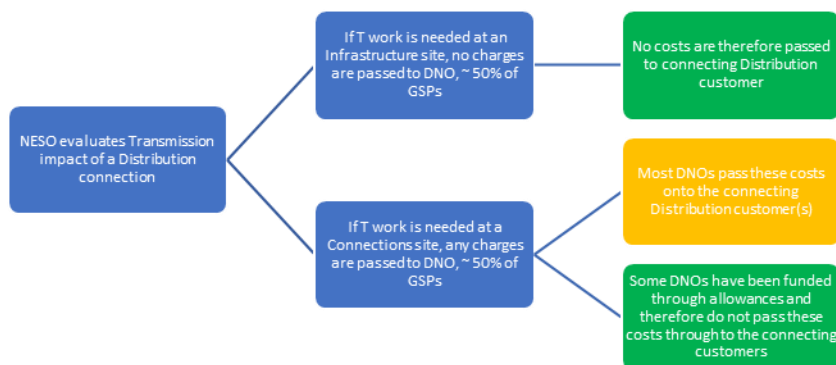
- 3.1 Customers connecting at Distribution can have an impact on the Transmission network and the CUSC sets out which projects are required to undertake what is known as a Transmission Evaluation Assessment (“TEA”). The result of that assessment might identify that there is transmission work needed to facilitate the connection. If that is the case, then there are numerous factors that affect whether the connecting customer is charged or not.

#### Transmission charging

- 3.2 Section 14 (Charging Methodologies) of the CUSC sets out how transmission system costs are recovered. In simple terms cost-recovery varies depending on whether the assets are 'connection assets' or 'infrastructure assets':
- 3.2.1 Connection assets are recovered via connection charges to a single user in accordance with the CUSC. A DNO is seen as a single user even if there are multiple embedded customers connected to that DNO's connection to the transmission network) and relate to assets solely required to connect that user to the transmission system; and
  - 3.2.2 Infrastructure assets are recovered via TNUoS charges and relate to assets shared by multiple transmission connected users.

#### Distribution charging

- 3.3 Whether or not the DNO is exposed to any charges therefore first depends on the categorisation of the transmission assets at GSP as described in 3.2. Only in the situation where the GSP is a Connection Site (as per 1.2 above) does the National Energy System Operator (“NESO”) pass through the costs to the DNO. In these instances, there are different treatments of the costs by DNOs. These are described at a high-level below, noting there are further subtleties between the approaches that have not been brought out for simplicity.
- 3.4 DNOs' approaches to recovering the capital components of these costs differ, with some effectively passing these costs through to the connection customer(s) that have triggered the transmission work via the distribution connection charge, while others have received price control funding to socialise those costs via DUoS customers.
- 3.5 If in the case of the former (costs recovered via the distribution connection charge), there is more than one customer, the costs are shared between them based on the relative capacities requested. Only if these connection offers are accepted does the DNO accept the offer from NESO and the work progress.
- 3.6 This is shown in the diagram below with the green boxes showing where the connecting customer does not receive a charge and the yellow box where they do.



- 3.7 The CUSC therefore creates a situation where costs may be recovered by the DNO or through the TNUoS charges depending on the classification of the relevant transmission assets. CMP 460 has been raised to review this treatment. Whilst it is out of scope for this CP to modify the CUSC charging arrangements, it can look to address charging differences for amounts to be recovered by DNOs. Note, any solutions proposed may be superseded by any changes to the CUSC. This CP therefore looks to develop solutions to address these different outcomes dependent on the GSP a distribution customer is being connected to.
- 3.8 For a GSP that is a Connection Site, a DNO's regulatory and commercial obligations (in lieu of allowed regulatory funding and varying interpretation of Clause 1.73 of Schedule 22 of the DCUSA) places the full capital cost of the relevant transmission reinforcement on the customer(s) that trigger(s) the need for upgrades – often requiring large, upfront capital contributions. This approach risks creating a disproportionate financial burden, such as for low-carbon and community energy projects, and introduces significant investment risk. Even where there are multiple distribution connected customers and the costs are shared amongst them, the cost liability for any given customer can change based on the actions of other customers. If one customer's connection offer is ended, either by them cancelling or being terminated, the costs are redistributed amongst the remaining customers. This could end up with all the costs falling to the "last connectee standing" and make the project unviable.
- 3.9 These distortions may hinder the timely connection of new generation and demand and slow down progress toward decarbonisation targets. The Proposer's view is that change is essential to ensure a fairer, more predictable, and strategically aligned charging regime that supports the energy transition and enables efficient network development.
- 3.10 However, an opposing view is that changing the arrangements such that a DNO recovers some or all of these costs via DUoS charges reduces or removes a locational cost signal for new projects. This would place a greater cost burden on the generality of customers, including those most vulnerable. An alternative solution is to standardise the current approach across all DNOs so that all relevant transmission costs (the capital components) are recovered via distribution connection charges. This solution does not address the inconsistencies with differing treatment for an Infrastructure Site and a Connection Site, but this is in scope of CMP 460.

## 4 Working Group Assessment

- 4.1 The DCUSA Panel established a Working Group to assess this CP. Meetings were held in open session and the minutes and papers of each meeting are available on the [DCUSA website](#).

### Relationship to CMP 460

- 4.2 The Working Group considered the relationship between this CP and CMP 460.
- 4.3 The Working Group discussed whether both changes should be aligned and coordinated, resulting in a joined-up approach to resolving the issues, including the timing of consultations, producing the reports and issuing these to the Authority for a decision.
- 4.4 The Working Group discussed the timelines for both changes, noting that the timeline for this CP may need to be tightened up should the Working Group wish to develop the solution(s) in a timeframe that allows the Authority to make a decision in time for implementation for ED3. It was considered that CMP 460 is likely to be significantly more complex given the potential impact on users with local service assets currently classed as infrastructure and potential need to rebalance TNUoS charging. In contrast, the Working Group believes that this CP can be implemented in a much shorter timeframe for a more narrowly focussed change to how DNOs recover the costs of transmission connection works.
- 4.5 The Working Group also noted that although it could be considered beneficial to develop both changes in a coordinated manner, it could not be presumed that either proposal will be approved by the Authority.
- 4.6 The Working Group agreed that this CP should be progressed in isolation, and at pace, in order to deliver solutions for voting and approval in time for inclusion in ED3.

### Issues Identified

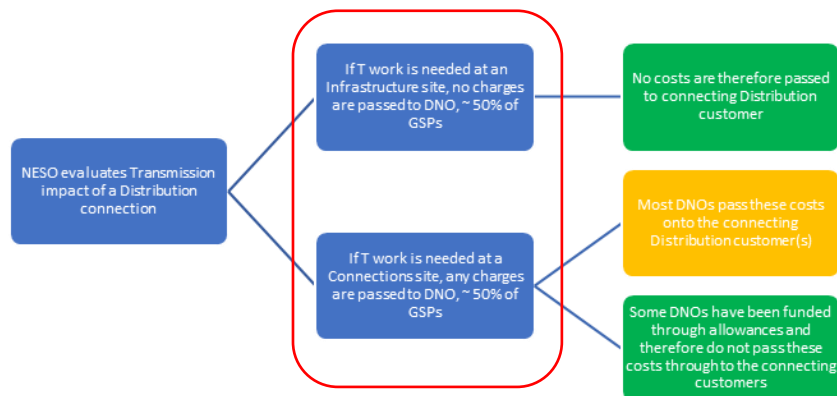
- 4.7 The Working Group discussed the issues identified in this CP, which it split into two distinct sets of issues:
- 4.7.1 the different treatment of costs in the CUSC charging methodology; and
  - 4.7.2 the risk of a variable and unsustainable financial burden on individual customers in those DNO areas which pass through all transmission-related connections costs.
- 4.8 The Working Group noted that a single solution may not resolve both of the issues identified and that, in the event there are multiple solutions to be taken forward, it may be necessary for the proposed solutions to be presented either as alternative variations (of which three may be included in the Change Report for this CP) or to be presented under separate CPs.
- 4.9 It was noted that the timescales would be challenging, should a separate CP be required, and it could not be presumed that either/both of the CPs would be approved.
- 4.10 In setting out the issues and potential options for solving them in the following sections, where any option would result in a DNO recovering less transmission costs from the connecting customer (via the distribution connection charge), the Working Group noted that it is not within

the scope of this CP to consider how these are recovered but have assumed that these would be recovered via DUoS charges to help stakeholders understand the potential consequences of the different options.

- 4.11 The impact of any options to be taken forward will need to be assessed following this consultation. This will need to include DNO funding in ED3, DNOs' ability to recover the costs via DUoS and the treatment in ED3. These may have a bearing on the timing of implementation but will be considered in more detail in the next phase of the development of this CP.

## Transmission Connection Asset Works Related Charges

- 4.12 The Working Group discussed that this issue arises from the transmission charging regime where an Infrastructure Site and a Connection Site result in different charging outcomes.
- 4.13 It was discussed that, with the forecast increase in infrastructure sites, where a Connection Site becomes shared by two or more transmission users, there is a high likelihood of different treatment arising based on which GSP a connection is made. It was noted (based on information provided by NESO) that two categories (Connection Site and Infrastructure Site) are split around half and half across England and Wales but in some areas Infrastructure Sites currently represent up to 60% (and therefore no charge made to the DNO where transmission work is needed). It was noted that the trend was for an increasing number of Infrastructure Sites as these shared sites may have led to a more efficient economical system in line with the obligations of transmission network company's primary obligations.



- 4.14 The Working Group reviewed four potential solutions to resolve this issue:
- 4.14.1 Option 1.1: no transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges;
- 4.14.2 Option 1.2: variant of 4.14.1: no transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges, *unless* the GSP is to feed a single distribution connected customer;
- 4.14.3 Option 1.3: extend the voltage rule to transmission charges and recover more via DUoS charges; and



- 4.14.4 Option 1.4: the application of a High-Cost Project Threshold (“HCPT”) to limit recovery via DUoS charges.

**Option 1.1: No transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges**

- 4.15 This solution would only apply where the DNO receives charges for any transmission works, i.e. related to a Connection Sites. In these situations, the drafting of the solution would be that the DNO would not pass on any charges to any distribution connecting customers for transmission works. Instead, the costs would be recovered from DUoS customers over the DNOs normal recovery timescales for investment, currently 45 years.
- 4.16 This would completely remove the different cost recovery approaches by DNOs such that distribution connecting customers would not contribute to these costs via the distribution connection charge irrespective of the classification of the GSP. This difference in treatment is outside of the connecting customer’s control and removes a perceived risk that only connections to an Infrastructure Site will be financially viable, which could lead to inefficient network design. Note that this would not apply to transmission fees which would still be chargeable to the customer via the distribution connection charge.

**Option 1.2: No transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges, unless the GSP is to feed a single customer**

- 4.17 This solution is the same as 4.15 Option 1.1 but adds an exception. The exception would only apply to GSPs where there is only one distribution customer connected to it. The drafting of the solution would be along the lines of defining the exception as “wholly or mainly” used by a single customer. This maintains integrity with the distribution charging principle of sole use and shared assets. It also maintains alignment with transmission charging principles so that there are no costs avoided for a single customer seeking to charge at transmission or distribution.
- 4.18 However, it does add complexity to the solution and the Working Group would need to consider how this single use is defined, both at the time of connection and in the future. This solution would remove the anomaly of the charging dependent on the GSP classification (that is outside of the connecting customers control) but maintain broad consistency if it was a single customer connecting to a new GSP.

**Option 1.3: Extend the voltage rule to transmission charges and recover more via DUoS charges**

- 4.19 This is an alternative solution to those above. The existing distribution charging principles are, apart from some specific exceptions, based on there being no charges for reinforcement for demand connections and generation connections only pay for any reinforcement at the same voltage at the point of connection. An alternative solution is to extend these principles to transmission charges.
- 4.20 This would result in demand connections not paying for any transmission work and generation connections would only pay if they were connecting at 132kV and then only for the 132kV element of the transmission work. Generation connections below 132kV would not pay for any

transmission works. This solution would remove the anomaly based on the GSP classification in most instances but would retain it for generation connections connecting at 132kV.

#### Option 1.4: Application of a HCPT to limit recovery via DUoS charges.

4.21 This solution is an extra feature that could be added to any of the three solutions above. It would be designed to protect DUoS customers from any extremes of costs. It could follow the principles used to develop the demand high-cost project threshold where the threshold was set to only be triggered for approximately the highest 5% of costs. This means that most projects are unaffected, but any extremely high-cost projects are still subject to a locational cost signal. This would need analysis to be undertaken to set an appropriate threshold.

#### Summary

4.22 The table below summarises the impact of each of the options against a number of perspectives.

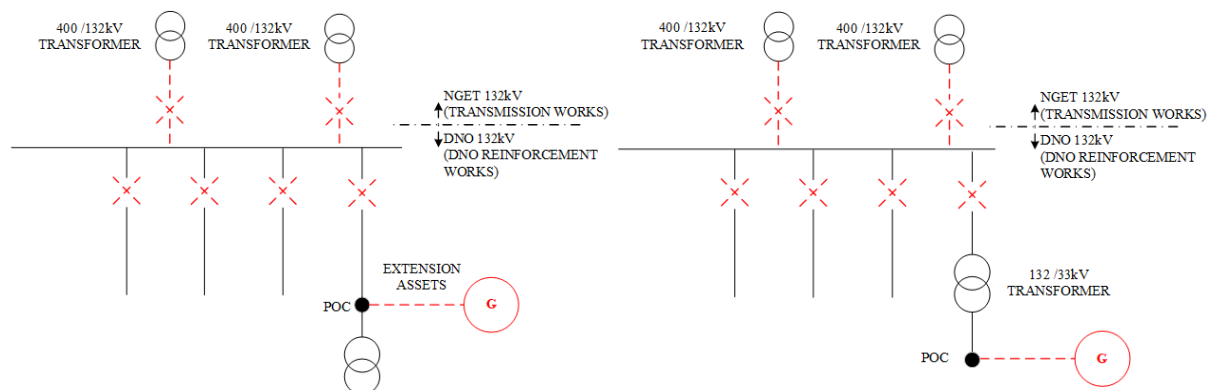
	1.1 No T costs passed to D	1.2 As 1.1 with exception for only one customer	1.3 Extending voltage rule	1.4 Adding HCPT to any of the options
Locational signal	Fully removed	Limited to a single customer at a GSP at 40-50% GSPs	Limited to 132kV connections and only weak signal at 40-50% GSPs	Limited to extreme cases at 40-50% GSPs
Consistency of charging outcome	No charges for any so consistent outcome	No charges apart from single customer at GSP, retains broad alignment with T charging	No charges apart from 132kV connections at a Connection site	Adds further exception for extreme cases
DUoS cost impact	Biggest increase in DUoS costs	Limited reduction from 1.1	Limit reduction compared to 1.1	Removes extreme cases from DUoS
Financial burden	No costs so no financial burden	Extra costs for single customer but aligns with outcome if they connected at T	Limited costs so limited burden	High financial burden for extreme cases but generally removed

## Illustrative examples

4.23 The Working Group developed a table to describe each solution, help demonstrate the potential consumer impacts and describe the challenges associated with the development of each option.

4.24 To help illustrate how the different solutions would work, some scenarios have been set out based on a single GSP with three types of connection being made to it:

- a) Generation (60 MW) connecting at 132kV
- b) Generation (20 MW) connecting at 33kV
- c) Generation (4 MW) connecting at HV or below
- d) Demand (80 MVA) connecting at any voltage



4.25 To help illustrate the options, the new GSP is assumed to create 240MW of capacity and cost £60m of which £5m is associated with the 132kV work on the transmission side of the interface.

			a) Generation (60 MW) connecting at 132kV		b) Generation (20 MW) connecting at 33kV		c) Generation (4 MW) connecting at HV		d) Demand (80 MVA) connecting at any voltage	
	Option	Description	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers
1.1	<b>No transmission costs passed through to distribution connecting customers</b>	Simple option whereby all T costs recovered from all DUoS customers.	£0	£60m	£0	£60m	£0	£60m	£0	£60m
1.2	<b>No T costs passed through to individual D connectee unless the GSP is to feed one customer</b>	This is as per 1.1 but with an exception if a new GSP is created “wholly or mainly” for a single customer. It is not meant to apply to where a new customer triggers a GSP and the extra capacity could be used by others.	£60m	£0	£60m	£0			£60m	£0

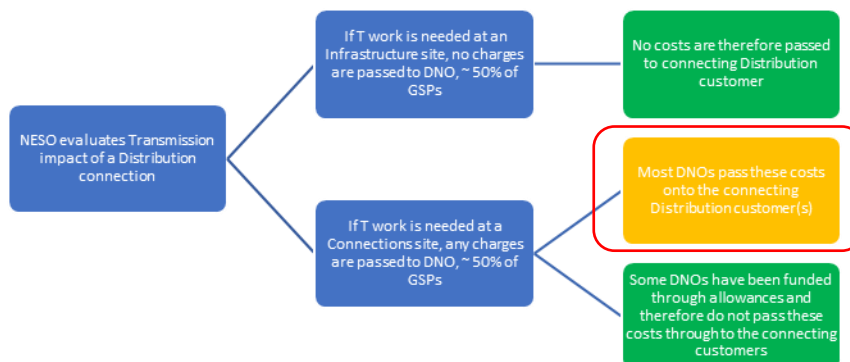
1.3	<b>Extend the voltage rule to T charges</b>	This is an alternative approach which gives different outcomes depending on the type and POC of the D customer. This means that customers only contribute to work at the same voltage level as the POC plus the voltage level above.	£5m	£55m	£0	£60m	£0	£60m	£0	£60m
1.4	<b>Application of a 'High-Cost Project Threshold'</b>	This is an additional feature which could be added to any of the options above. Assuming consistency with the existing HCPT (that applies only to D reinforcement), if the applicable costs are greater than the threshold, then the customer is charged all the applicable reinforcement. Only the reinforcement at the same voltage level plus the one above is considered. Figures assume it is triggered.	£60m	£0	£5m	£55m	£0	£60m	£60m	£0

## The risk of a variable and unsustainable financial burden on Individual Customers

4.26 The Working Group discussed that this issue arises where DNOs pass on the costs of any transmission changes to the distribution connecting customers, noting that this is the case for most but not all DNOs. Note also that this only applies to non-Infrastructure sites, representing about 40-50% of GSPs.

### **Connection cost sharing**

4.27 Where there are a number of new customers at a connection GSP, these costs are typically shared based on customers' respective capacities. Should any customers fall away, either by voluntarily withdrawing, being terminated or not meeting Gate 2 requirements, the totality of the costs can fall to the "last person standing". This provides uncertainty and an increase in costs and can happen at any time in the project lifecycle. This creates uncertainty for any given project and could change the commercial viability of a project at any time and when significant investment has been made. It also can result in a situation where a single project has to fund all of the work which poses a significant cost risk, even with the potential for costs to be shared with future connections. The working group considered how these issues could be mitigated.



4.28 The Working Group reviewed four potential solutions to resolve this issue:

4.28.1 Option 2.1 - cost apportionment;

4.28.2 Option 2.2 - cost apportionment with applicability criteria;

4.28.3 Option 2.3 - cost apportionment with a voltage rule applied to transmission charges; and

4.28.4 Option 2.4 - the application of a High-Cost Project Threshold.

### **Option 2.1 - Cost apportionment**

4.29 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:

4.29.1 The costs would be fixed for the individual customers and would not change irrespective of the outcome of other customers contracts; and

4.29.2 The quantum of the costs would be lower as the connecting customer would only pay a proportion of the costs.

4.30 The approach to cost apportionment could mirror the existing ones for distribution but would need to be reviewed. Currently these are based on the proportion of capacity used based on thermal or fault level and a summary is provided as Attachment 3.

#### **Option 2.2 - Cost apportionment with applicability criteria**

4.31 This solution builds on Option 2.1 by adding explicit criteria to clarify which connecting customers are exposed to these charges. Without some additional criteria, the costs of the transmission works would in theory be cascaded down to all connections that are made to the GSP. This would otherwise mean that the costs should be passed through to domestic customers connecting at low voltage.

4.32 In this solution, the criteria could be based on the size of the new connection, e.g. for England and Wales this could be aligned to the thresholds for the requirement for a Transmission Evaluation Assessment. Noting that these vary by GSP at either 1MW or 5MW so would need consideration.

4.33 Alternatively, in this solution, the criteria could be based on the voltage level of connection. This could be based on one voltage level to be consistent with how generation is charged or two voltage levels to be consistent with how the HCPT is calculated e.g., for England and Wales this could limit the cost exposure to connections with a Point of Connection voltage of 33kV or higher.

#### **Option 2.3 - Cost apportionment with a voltage rule applied to transmission charges**

4.34 This solution would apply a voltage rule to the transmission costs before applying a cost apportionment as in 4.29. This could be based on the existing voltage rule for generation resulting in the connecting customer only pays for a portion of transmission costs at the same voltage as the point of connection. Alternatively, two voltage levels could be applied such that the connecting customer pays for the transmission costs at the same voltage level as the point of connection and the voltage level above.

#### **Option 2.4 - Application of a High-Cost Project Threshold to limit recovery via DUoS.**

4.35 This solution is an extra feature that could be added to any of the three solutions above. It would be designed to protect DUoS customers from any extremes of costs. It could follow the principles used to develop the demand high-cost project threshold where the threshold was set to only be triggered for approximately the highest 5% of costs. This means that most projects are unaffected, but any extremely high-cost projects are still subject to a locational cost signal. This would need analysis to be undertaken to set an appropriate threshold.

## Summary

4.36 The table below summarises the impact of each of the options against a number of perspectives.

	2.1 Cost apportionment	2.2 As 2.1 with a threshold	2.3 As 2.1 but apply voltage rule	2.4 Adding HCPT to any of the options
<b>Locational signal</b>	Some cost signal at 40-50% GSPs but potentially down to LV connections	Some costs at 40-50% GSPs but only those connections above the threshold	Only a cost signal to 132kV connections at 40-50% GSPs	Limited to extreme cases at 40-50% GSPs
<b>Consistency of charging outcome</b>	Potential for costs at only 40-50% of GSPs	Potential for costs at only 40-50% of GSPs	Potential for costs at only 40-50% of GSPs	Potential for costs at only 40-50% of GSPs
<b>DUoS cost impact</b>	Depends on timing and utilisation of the new capacity. If fully used, then little or no impact.	Depends on timing and utilisation of the new capacity. Capacity under the threshold will impact DUoS.	Most of costs will go to DUoS	Adds protection for DUoS from extreme cases.
<b>Financial burden</b>	More proportionate cost if only one connecting customer	More proportionate cost if only one connecting customer	Limited to 132kV connections	Large cost burden on most extreme cases.

## Illustrative examples

4.37 As with the first four solutions, the Working Group developed a table to describe each solution, help demonstrate the potential consumer impacts and describe the challenges associated with the development of each option.



			a) Generation (60 MW) connecting at 132kV		b) Generation (20 MW) connecting at 33kV		c) Generation (4 MW) connecting at HV		d) Demand (80 MVA) connecting at any voltage	
	Option	Description	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers
2.1	<b>Cost apportionment</b>	The approach would be for the connecting customer to pay their proportion of the total capacity created.	£15m <u>60</u> x £60m 240	£45m	£5m <u>20</u> x £60m 240	£55m	£1m <u>4</u> x £60m 240	£59m	£20m <u>80</u> x £60m 240	£60m
2.2	<b>Cost apportionment with applicability criteria based on capacity</b>	This would be similar to 2.1 but adding an explicit lower threshold. The threshold could be defined by the size of the new connection eg 5MW. The costs in the table have assumed a threshold of 5MW.	£15m <u>60</u> x £60m 240	£45m	£5m <u>20</u> x £60m 240	£55m	£0 (below threshold)	£60m	£20m <u>80</u> x £60m 240	£60m

2.3	<b>Cost apportionment with the voltage rule applied to transmission charges</b>	This means that customers only contribute to work at the same voltage level as the POC. Cost apportionment would then be applied to the work in scope.	£1.25m $\frac{60}{240} \times £5m$	£58.75m	£0m	£60m	£0	£60m	£1.67m $\frac{80}{240} \times £5m$ Assuming a 132kV connection, otherwise £0	£58.33m
2.4	<b>Application of a High-Cost Project Threshold to limit recovery via DUoS</b>	This is an additional feature which could be added to any of the options above. Assuming consistency with the existing HCPT (that applies only to D reinforcement), if the applicable costs are greater than the threshold, then the customer is charged all the applicable reinforcement. Only the reinforcement at the same voltage level plus the one above is considered. Figures assume it is triggered.	£60m	£0	£5m	£55m	£0	£60	£60m if POC is 132kV £5m if POC is 33kV £0m if POC is HV	£0 if POC is 132kV £55m if POC is 33kV £60m if POC is HV

### Standardised approach

4.38 The working group also considered an option where a consistent approach was applied by all DNOs such that any transmission costs would be charged to the connecting customer or customers that trigger the work.

### **Option 3.1 - DNO Parties apply a consistent locational signal – no DUoS impact**

4.39 This option would standardise the current approach across all DNOs so that all relevant transmission costs (the capital components) are recovered via distribution connection charges. It seeks to promote consistent application across all DNOs, while preserving locational cost signals and protecting DUoS customers from uncontrollable costs with the Electricity Connection Charges Regulation (“ECCR”) providing future safeguards against the financial burden of upfront costs.

### **Summary**

4.40 The table below summarises the impact of this option against a number of perspectives.

3.1 Cost in full to first comers	
Locational signal	Strong location cost signal at 40-50% GSPs.
Consistency of charging outcome	Ensures a consistent approach across all DNOs with potential for costs at only 40-50% of GSPs.
DUoS cost impact	Protects DUoS customers, little or no impact.
Financial burden	High if only one connecting customer. Burden is reduced if multiple customers as costs are shared. The ECCR provides future safeguards against the upfront financial burden.

			e) Generation (60 MW) connecting at 132kV		f) Generation (20 MW) connecting at 33kV		g) Generation (4 MW) connecting at HV		h) Demand (80 MVA) connecting at any voltage	
	Option	Description	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers
3.1	<b>DNO parties apply a consistent locational signal – no DUoS impact</b>	This proposal clarifies what transmission-related costs DNOs should recover from connecting and wider customers, ensuring consistent application across DNOs. It maintains locational cost signals, protects DUoS customers from uncontrollable costs, and leverages ECCR regulations to reduce future upfront financial burdens	£60m	£0m	£60m	£0m	£60m	£0m	£60m	£0m

#### Implementation of any changes

- 4.41 The working group discussed the challenges of implementing any changes, particularly due to the differences in current approaches. Working group members identified the desirability of being able to apply any changes to existing contracted projects that are going through Connections Reform.
- 4.42 Overall, the working group considered that a no detriment approach should be taken to implementing any change. Therefore, if any change was approved, it should not result in any increase in costs for existing contracted projects; if it resulted in a reduction in costs then this could be applied more reasonably. For new applications after the implementation date, then the changes would apply.

#### Consumer Impact/Impact Assessment

- 4.43 The Working Group discussed the need for an impact assessment, noting that each option impacts consumers (with costs being removed from some consumers and socialised across others, to various degrees).
- 4.44 The Working Group also noted the previous send-backs for both DCUSA and CUSC proposals, citing the Authority's assessment that, in each case, the impact assessment was insufficient to allow it to make a decision.
- 4.45 The Working Group discussed the challenges associated with performing an impact assessment for this CP, due to the timescales the Working Group is working towards and the incoming connection reforms, the latter of which will result in some costs being removed but which was, as yet, unquantifiable. It was noted that any impact assessment performed by this Working Group would be invalid, due to the implementation of connection reforms, and would paint a worst-case scenario that, due to its significant materiality, could lead to the rejection of the proposed solution(s) by Parties, through the vote, or by the Authority, based on data which is not a reflection of the future reality.
- 4.46 The Working Group included scenarios in the tables under each set of options, to demonstrate the way that costs could be allocated under each of the options.
- 4.47 The Working Group agreed to revisit the prospects of performing an impact assessment once the solution(s) to be taken forward are determined, following a review of feedback to this consultation, but noted that the same issues pertaining to the accuracy and validity of the impact assessment would likely persist.

**Question 1 – Do you understand the intent of the CP?**

**Question 2 – Are you supportive of the principle of the CP?**

**Question 3 – Which of the proposed solutions for the 'Transmission Connection Asset Works Related Charges' defect (options 1.1 to 1.4) should the Working Group further develop and present in the change report for voting? Please provide your rationale.**

**Question 4 – Should any of the proposed solutions referenced in Question 3 not be taken forward? Please provide your rationale.**

**Question 5 – Which of the proposed solutions for the ‘risk of a variable and unsustainable financial burden on individual customers’ defect (options 2.1 to 2.4) should the Working Group further develop and present in the change report for voting? Please provide your rationale.**

**Question 6 – Should any of the proposed solutions referenced in Question 5 not be taken forward? Please provide your rationale.**

**Question 7 - Should the proposed alternative solution under option 3.1 be taken forward? Please provide your rationale.**

**Question 8 – What are the pros and cons of adopting an approach that causes no detriment to contracted customers? Please provide your rationale.**

**Question 9 – Do you have any other comments?**

## 5 Relevant Objectives

### Assessment Against the DCUSA Objectives

5.1 For a DCUSA Change Proposal to be approved it must be demonstrated that it better facilitates the DCUSA Objectives. This CP is being assessed against the DCUSA Charging Objectives.

DCUSA Charging Objectives	
<input checked="" type="checkbox"/>	That compliance by each DNO Party with the Charging Methodologies facilitates the discharge by the DNO Party of the obligations imposed on it under the Act and by its Distribution Licence
<input checked="" type="checkbox"/>	2. That compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)
<input checked="" type="checkbox"/>	3. That compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business
<input checked="" type="checkbox"/>	4. That, so far as is consistent with Clauses 3.2.1 to 3.2.3, the Charging Methodologies, so far as is reasonably practicable, properly take account of developments in each DNO Party's Distribution Business
<input type="checkbox"/>	5. That compliance by each DNO Party with the Charging Methodologies facilitates compliance with the EU Internal Market Regulation and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators; and
<input checked="" type="checkbox"/>	6. That compliance with the Charging Methodologies promotes efficiency in its own implementation and administration.

**Question 10 – Do you consider that any of the options would significantly better facilitate the DCUSA Charging Objectives? Please give supporting reasons.**

## 6 Impacts & Other Considerations

### Does this Change Proposal impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

6.1 Consideration may be needed for potential DUoS SCR impacts.

### Consumer Impacts

6.2 It is anticipated that the connection costs for in scope consumers will be reduced, however depending on the solution taken forwards this may result in costs being socialised across other consumers. The challenges around performing an impact assessment are described in paragraph s 4.43 to 4.47, earlier in this document.

### Environmental Impacts

6.3 In accordance with DCUSA Clause 11.14.6, the Working Group assessed whether there would be a material impact on greenhouse gas emissions if this CP was implemented. The Working Group did not identify any material impact on greenhouse gas emissions from the implementation of this CP.

**Question 11 – Are you aware of any wider industry developments that may impact upon or be impacted by this CP?**

## 7 Implementation

7.1 It is proposed that, if this CP is approved, the solution is implemented 5 Working Days after Authority approval.

**Question 12 – Are you supportive of the proposal to implement the solution 5 Working Days after Authority approval?**

## 8 Legal Text Commentary

8.1 The Working Group has not developed legal text for any of the options but will do so once the options have been shortlisted following this consultation.

8.2 However, the Working Group expects Schedule 22 (Common Connection Charging Methodology, the CCCM) to be the Schedule to require amendments to achieve the intent of this proposal, in particular paragraphs 1.72 and 1.73 which refer, at a high level, to the arrangements for 'Independent System Operator and Planner (ISOP) charges'.

8.3 Other potentially relevant sections are those setting out 'Cost Allocation' (1.8 to 1.39) and 'Rebates' (1.44 – 1.47). The section on 'Worked Examples' may require additional examples.

8.4 This being a proposal that is affected by both transmission and distribution charging arrangements, the Working Group has noted that a number of relevant and more detailed rules

are set out in CUSC Section 14, the Charging Methodologies (e.g. sub-sections 14.3 and 14.4.). However, these sit outside the scope of DCP 461 but will have to be taken into account.

- 8.5 The Working Group has also noted that existing distribution licence requirement are relevant, in particular Special Condition 6.1 which provides for the pass-through of Transmission Connection Point Charges. Again, these provisions sit outside the scope of this proposal but will have to be taken into account.

**Question 13 – Do you have any comments on the commentary provided for the proposed legal text changes?**

## 9 Consultation Questions

- 9.1 The Working Group is seeking industry views on the following consultation questions:

No.	Questions
1	Do you understand the intent of the CP?
2	Are you supportive of the principle of the CP?
3	Which of the proposed solutions for the 'Transmission Connection Asset Works Related Charges' defect (options 1.1 to 1.4) should the Working Group further develop and present in the change report for voting? Please provide your rationale.
4	Should any of the proposed solutions referenced in Question 3 not be taken forward? Please provide your rationale.
5	Which of the proposed solutions for the 'risk of a variable and unsustainable financial burden on individual customers' defect (options 2.1 to 2.4) should the Working Group further develop and present in the change report for voting? Please provide your rationale.
6	Should any of the proposed solutions referenced in Question 5 not be taken forward? Please provide your rationale.
7	Should the proposed alternative solution under option 3.1 be taken forward? Please provide your rationale.
8	What are the pros and cons of adopting an approach that causes no detriment to contracted customers? Please provide your rationale.
9	Do you have any other comments?
10	Do you consider that any of the options would significantly better facilitate the DCUSA Charging Objectives? Please give supporting reasons.



11	Are you aware of any wider industry developments that may impact upon or be impacted by this CP?
12	Are you supportive of the proposal to implement the solution 5 Working Days after Authority approval?
13	Do you have any comments on the commentary provided for the proposed legal text changes?

9.2 Responses should be submitted using Attachment 2 to [dcusa@electralink.co.uk](mailto:dcusa@electralink.co.uk) by no later than 28 November 2025.

9.3 Responses, or any part thereof, can be provided in confidence. Parties are required to clearly indicate any parts of a response that are to be treated confidentially.

## 10 Attachments

- Attachment 1 – DCP 461 Change Proposal Form
- Attachment 2 – DCP 461 Consultation Response Form
- Attachment 3 – Cost Apportionment Factor