

## Distribution Charging Methodologies Development Group (“DCMDG”) - Meeting 98

16 April 2026 at 10:00 via Microsoft Teams

Attendees	Company
Cass Bothwell [CB <sup>1</sup> ]	Scottish Power
Charles Mott [CM]	SSE
Chris Barker [CB <sup>2</sup> ]	ENWL
Chris Ong [CO]	UKPN
David Fewings [DF]	Sustainable Energy First
Diandra Orodan [DO]	BUUK
Dimuthu Wijetunga [DW]	Shell
Donna Jamieson [DJ]	IDCSL
Edda Dirks [ED]	SSE Generation
Emma Clark [EC]	SSE
Emma Robinson [ER]	E.ON
Francisca Wiggins [FW]	P3P Partners
Georgia Preece [GP]	NPg
Gordon Frazer [GF]	NESO
Itunu Akin-Olawale [IAO]	SP ENW
James Knight [JK]	Centrica
John Harmer [JH]	Waters Wye
Kavya Kavya [KK]	Brook Green
Laura Waldron [LW]	Engie
Lee Stone [LS]	EON
Louise Robinson [LR]	ESPUG
Mariana Mesaros [MM]	St Clements
Meg Wong [MW]	Stark
Mike Smith [MS]	Elaxon
Nadir Hafeez [NH]	Ofgem
Niall Coyle [NC]	NESO
Nik Wills [NW]	Stark
Ryan Farrell [RF]	NPg
Seun Adedapo [SA]	NGED
Tony Collings [TC]	Ecotricity
<b>Secretariat</b>	
Craig Booth [CB <sup>3</sup> ] (Secretariat)	ElectraLink
Richard Colwill [RC] (Chair)	ElectraLink
<b>Apologies</b>	
Andrew Malley [AM]	Ofgem

## 1. Administration

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### Recording

- 1.1 The purpose of this recording is purely to aid the Technical Secretariat in producing an accurate report of the meeting. The recording will be deleted after the minutes are approved.

### Competition Law Guidance

- 1.2 The Working Group reviewed the “Competition Law Guidance” and it was noted that all members agreed to be bound by the Competition Law Guidance for the duration of the meeting.

### Draft Minutes

- 1.3 Attendees reviewed the draft minutes from the previous meeting.
- 1.4 ED queried whether an action needed to be recorded against the AOB item raised by RF in relation to the Annual Allocation Review/Market-Wide Half Hourly.
- 1.5 RF explained that either a derogation or a CP would need to be raised, but no action had yet been taken in relation to this.
- 1.6 ED queried whether this related to DCP 439.
- 1.7 RF clarified that while it is a similar type of issue, DCMDG 439 focused on backdating, whereas this issue relates specifically to MPAN migration data. Once an MPAN migrates to Market-wide Half Hourly (MHHS), changes cannot be made to periods prior to the migration date. As a result, MPANs migrated from 1 August 2025 up to the next Annual Allocation Review cannot be backdated beyond the migration date, even if correction would otherwise be required. This is due to system limitations that prevent backdating beyond the MHHS migration point. Historically, the rules allowed going back “as far as possible”, which proved impractical (up to four years), leading to a derogation in the first year limiting backdating to 14 months. The rules were subsequently amended to set a clear cut-off of 1 August of the previous year.
- 1.8 LS supported RF’s point that settlement transition considerations begin from October, with a phased change in timescales. The allowable backdating window is expected to reduce from seven months to four months next year, creating a temporary seven-month period during the transition. This phasing complicates matters for manual allocation, which typically requires at least 12 months of data and potentially longer depending on timing. These shortened and changing windows are therefore not helpful from a manual allocation perspective. LS noted this information is recent, having been discussed at the Settlement Transmission Transition Expert Group meeting the previous day.

## 2. DCMDG Forward Work Plan and Issues Log

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- 2.1 The group reviewed the DCMDG Forward Work Plan and Issues Log, latest updates can be found in attachment 1.

### Action Updates

- 2.2 Action 09/06 – The Chair noted that the issue form had not been circulated prior to the meeting and stated this would be sent.

Action 98/01	The Secretariat to circulate the issue form.
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- 2.3 Action 97/02 – The Chair explained that this will remain open as a standing action.
- 2.4 Action 95/01 – The Chair advised no updates had been received on this.
- 2.5 Action 95/04 – The Chair advised invitations to join the group had been sent and a poll would be issued next week to agree the first meeting date. This action remains open.
- 2.6 Action 96/01 – The Chair advised CO would provide an update which would be captured in the minutes. This action remains open.
- 2.7 Action 96/02 – The Chair advised this is awaiting a CP to be raised. The Chair agreed to check with AM for a date by which this is expected to be resolved.
- 2.8 Action 97/03 & 97/04 – The Chair advised the guidance had been circulated but may need to be a minor update following some feedback. This action was closed, however a new action opened.

Action 98/02	The Secretariat to update and recirculate the guidance.
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- 2.9 Action 97/05 – The Chair advised this action remains ongoing as agreed with the DCMDG.
- 2.10 Action 97/06 – The Chair advised this was added to the agenda. This action has been closed.

## DCMDG Live Subgroups

- 2.11 Subgroup 02 [\*'Annual Allocation Review and Exceptional Circumstances for Future Electricity Transmission Price Control'\*](#)
- No further updates were provided since the previous DCMDG meeting.
- 2.12 Subgroup 03 [\*'Site Specific Shared Network Asset Categories'\*](#)
- No further updates were provided since the previous DCMDG meeting, however, and RFI is currently being developed.

## 3. Ofgem Update

- 3.1 The Chair explained that AM was not able to attend the meeting today.
- 3.2 ED asked for an update on the status of the DCP 412 CP that has been with Ofgem for decision, noting that a previous Panel update suggested Ofgem was considering an impact assessment and consultation.
- 3.3 NH confirmed that DCP 412 is now being progressed after a delay due to its links with wider long-term review work. Ofgem is planning to issue a “minded-to decision” consultation in June, followed by a final decision in late summer or early autumn.
- 3.4 ED welcomed the update and asked that further updates be provided at future meetings.
- 3.5 The Chair thanked NH for the update and acknowledged Ofgem’s engagement.

## 4. Update on Allowed Revenue for 2028/29

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- 4.1 CO provided an update on discussions about how DNOs should treat 2028–29 allowed revenue.
- 4.2 Since the last update, one further meeting has taken place, with another scheduled later that day involving ENA and DNOs to develop justification and evidence for the available options. There have been three to four meetings overall involving DNOs, ENA, and Ofgem, and multiple options remain under consideration.
- 4.3 Using the final year of ED2 allowed revenue is effectively ruled out, as it was not intended to be used at ED2 outset. Re-using business plan values, as done at the start of ED2, is also not favoured due to the significant charging issues it caused (notably the 24–25 charge adjustments).
- 4.4 Current thinking is leaning towards using either draft or final audit determination values, though no decision has been made.
- 4.5 Ofgem plans to engage suppliers and other parties for views, with Energy UK also being consulted.
- 4.6 CO stated there is no perfect solution, as final revenue figures will not be confirmed until late November 2027, creating risk regardless of the approach taken. The objective is to select a figure that is as realistic as possible to avoid large “catch-up” adjustments in ED3.
- 4.7 Further updates are expected at the next DCMDG, following upcoming meetings with ENA/DNOs and Ofgem.

## 5. Residual Charges for Private Networks (DCP 328 Query)

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- 5.1 NC raised a query received from a customer on a private network who has a third-party access arrangement with a supplier different from the private network operator’s supplier. The customer is being charged residuals twice:
  - 5.1.1 once directly based on their own meter; and
  - 5.1.2 again via a share of the private network’s residual charges passed on to them.
- 5.2 NC stated he believes this treatment is consistent with current charging methodologies but noted that DCP 328 was intended to address or codify a solution to this kind of double-charging issue. NC asked whether there has been any progress or conclusion since the DCUSA 328 rejection, and whether DNOs agree that the current charging treatment is appropriate.
- 5.3 The question was opened to the group to confirm current DNO practice and any updates on this issue.
- 5.4 LS agreed that the customer’s experience appears consistent with current arrangements, noting he does not represent a DNO. LS stated that, in his experience, sites with private wire/private network arrangements typically have residual charges applied at the boundary meter, with costs then passed through internally if a charging methodology is in place. If no such methodology exists, customers within the private network may not be charged directly, as supply is treated at the boundary.
- 5.5 In this case, the customer is being charged both directly on their own meter and indirectly via the private network’s boundary charges, which LS acknowledged would follow from having a methodology in place. LS noted that this issue has not progressed since DCP 328 closed, recalling that it was difficult to reach a decision at the time and is effectively not moving forward amid other priorities.

- 5.6 NC confirmed he had mainly wanted to sense-check that understanding, which the discussion supported, and that there has been no subsequent progress on resolving the issue.
- 5.7 ED noted that after DCP 328 was rejected, a DCMDG subgroup was established to try to progress the issues the modification was intended to address. The subgroup aimed to find a way forward on private network and residual charging issues, including clarifying responsibilities and treatment. The subgroup unfortunately made little progress and did not meaningfully advance the issue.
- 5.8 Ofgem was expected to play an important role in clarifying the way forward, particularly given the wider complexities and grey areas in the private network landscape, but this did not result in concrete outcomes.
- 5.9 The Chair suggested he could raise this with Ofgem to ensure this remains on Ofgem's radar.

## 6. Charging Methodologies and Associated Distribution Systems

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- 6.1 MS introduced himself as a Metering Analyst at Elexon, part of a three-person metering team within the Market Design and Customer and Code Management functions.
- 6.2 The team's core responsibilities include:
  - 6.2.1 approving half-hourly settlement meters and metering protocols (used by HHDCs / metering services);
  - 6.2.2 handling metering dispensations and trading unit applications; and
  - 6.2.3 validating CBA registration information, such as transmission boundary points, GSPs, BM Units, meter technical details, and aggregation rules, typically against single-line diagrams.

### BSC Measurement Requirements – Section K

- 6.3 Under BSC Section K, certain electricity flows must be measured for settlement: boundary point flows and system connection point flows.
- 6.4 Boundary points measure flows between a customer or generator and the Total System:
  - 6.4.1 Import = flow from the Total System to a customer/generator; and
  - 6.4.2 Export = flow from a generator towards the Total System.
- 6.5 The Total System consists of the transmission system, all distribution systems, and offshore transmission user assets.
- 6.6 Suppliers (as BSC Parties) are responsible for registering import/export metering at boundary points for their customers or third-party generators.
- 6.7 Responsibility for the Total System under the BSC generally sits with LDSOs (covering both LDSOs and IDNOs) and NETSO/NESO as the transmission system operator.
- 6.8 System connection points are where systems interconnect, such as:
  - 6.8.1 Transmission to distribution (Grid Supply Points – GSPs), and
  - 6.8.2 Distribution to distribution connections across different GSP groups (DSCPs).

- 6.9 Normally, LDSOs register GSP and DSCP metering, but in specific cases—such as transmission assets at or above 132 kV connecting directly into distribution—NETSO is responsible for the metering under the BSC.
- 6.10 Offshore boundary points are registered under CVA (Central Volume Allocation).

## **BSC Measurement Requirements – Section L**

- 6.11 BSC Section L requires metering equipment to be installed to measure active energy (and sometimes reactive energy) at boundary points and system connection points.
- 6.12 Codes of Practice (“CoP”) define the required accuracy and specify where this accuracy must be maintained, known as the Defined Metering Point (“DMP”).
- 6.13 Since a change around 2017, all DMPs have been aligned with boundary points and system connection points.
- 6.14 If required accuracy cannot be maintained at the DMP and loss compensation is needed, the metering system registrant must apply for a metering dispensation.
- 6.15 Dispensations and other non-compliances may be approved by either the BSC Panel or Elexon, though Elexon’s approval powers are limited, mainly to cases such as co-generation where the only issue is the meter not being located exactly at the DMP.
- 6.16 Active energy data is required primarily for settlement, but may also be used for use-of-system charging.
- 6.17 Reactive energy requirements in the CoPs are specifically for use-of-system charging and are not used for settlement.
- 6.18 Data collectors retrieve, validate, and where necessary estimate metering data (particularly reactive energy), then pass it to system operators and meter registrants.
- 6.19 This data is used by NETSO, LDSOs, and IDNOs for use-of-system charging and system planning.
- 6.20 Where settlement meters also serve as billing meters (which is usually the case), suppliers use the data to bill customers or pay generators for active energy, and to pass through use-of-system charges, particularly for smaller customers.

## **Modification Proposal P062**

- 6.21 A BSC modification (P062) approved in 2002 introduced the concept of an Associated Distribution System (ADS). This is essentially a private network that is not operated by a licensed DNO, but whose boundary points are registered within the LDSO’s MPAN registration systems.
- 6.22 As a result, boundary point metering between the LDSO/IDNO and the private network is no longer required for settlement purposes and should be deregistered for settlement. However, that boundary metering may still be needed for Use of System charging, which would require private data-collection arrangements, as the meters are no longer settlement meters.
- 6.23 Customer and generator meters within the ADS are used for settlement, and in practice often also appear to be used for Use of System charging, though this is not always consistently applied.



## UOS Impact

- 6.24 Some customers connected to the private network may be charged under EDCM (e.g., based on higher-voltage connections), while others may be charged under CDCM, depending on voltage level.
- 6.25 The view expressed is that customers and generators connected via an ADS should be treated the same as those connected directly to an LDSO or IDNO network, since an ADS is effectively part of the total system as a distribution system.
- 6.26 Accordingly, charges should reflect the voltage level at which customers connect, not the existence of the ADS itself.
- 6.27 The issue was opened to the Distribution Charging Methodology Working Group to consider whether this interpretation is agreed and whether changes to codes or charging methodologies may be needed to support it.

## Discussion

- 6.28 LS noted that although charging by connection voltage rather than boundary had been proposed, it was rejected, and currently DCUSA does not clearly recognise Associated Distribution Systems (ADSs) beyond the boundary point.
- 6.29 MS acknowledged this and said he would need to look further into the rejected proposal.
- 6.30 FW added practical examples from experience with private/associated networks:
- 6.30.1 where an ADS is connected at 11 kV, DNOs generally accept charging customers based on their actual connection voltage; and
  - 6.30.2 problems arise when the boundary to the DNO is at 33 kV, but customers connect at HV or LV, creating a mismatch between charging methodologies (e.g. being forced into EDCM rather than CDCM).
- 6.31 FW highlighted a largely unused provision in DCUSA Schedules 17 and 18 (within the charging methodologies), which allows an unlicensed network that is part of the Total System and open to supply to be treated as an IDNO.

### **28. DNO PARTY TO UNLICENSED NETWORKS**

- 28.1 Unlicensed networks have a choice. If they are part of the Total System under the Balancing and Settlement Code with the network open to supply competition, and if they are party to the DCUSA, and have accepted the obligations to provide the necessary data, they can, if they wish, be treated as LDNOs.
- 28.2 Otherwise, the DNO Party applies the EDCM to calculate an import and export charge based on capacity and power flow data metered at the boundary. Any sole use assets specific to the unlicensed network are charged as a p/day sole use asset charge calculated as applicable to a normal EDCM Connectee.

- 6.32 FW suggested this provision may have been intended to address exactly this ADS charging mismatch, giving DNOs flexibility to charge based on customer connection voltage.
- 6.33 FW suggested that, in practice, a licensed supplier could effectively manage a private network, which may be the implied mechanism behind certain DCUSA provisions.

- 6.34 LS noted that this begins to look like a legal or deeds-based arrangement, as the idea of a supplier operating or “owning” a network under DCUSA does not sit comfortably with their traditional role. However, LS agreed the DCUSA wording may be open enough to allow that interpretation.
- 6.35 FW suggested that without linking ADS provisions under the BSC to this DCUSA provision, the clause appears stranded and difficult to rationalise, suggesting it may have been intended as a bridge between the two frameworks. FW proposed that even if this was the original intent, further code changes may still be needed to clarify the position going forward.
- 6.36 MS suggested investigating which DCUSA change proposal introduced the provision, whether it aligned with P062 (ADS introduction) or another change, and reviewing supporting documentation to understand the original intent.
- 6.37 FW noted that previous attempts to trace the history of the provision (with support from DCUSA) found no clear explanation for its inclusion, despite detailed historical review. FW suggested a renewed review, focusing on dates and alignment with ADS implementation, might be worthwhile.
- 6.38 MS agreed to explore whether Elexon’s market design team, including longer-serving colleagues, might recall the rationale behind the relevant DCUSA change.
- 6.39 LS suggested that the next useful step may be to seek legal advice (e.g., from Gowling) on the interpretation FW outlined, particularly around how DCUSA provisions might apply to ADSs.
- 6.40 The Chair agreed this could be explored, noting it would require Panel agreement due to the associated cost, but indicated this should be manageable.
- 6.41 MS highlighted an additional complication relating to Line Loss Factors (LLFs):
- 6.41.1 LDSOs typically calculate LLFs up to the boundary point with a private network, which is appropriate; and
  - 6.41.2 prior to ADS status, private networks either compensate settlement meters for internal losses or absorb losses through boundary and difference metering.
- 6.42 Once a network becomes an ADS, it appears LDSOs continue calculating LLFs only to the original boundary, rather than to individual customer connection points within the ADS.
- 6.43 This raises an unresolved question about how losses within ADSs should be treated, and whether:
- 6.43.1 boundary point meters should continue to be loss-compensated to the defined metering point; or
  - 6.43.2 losses should remain the responsibility of the private/ADS network, despite it effectively being treated as part of the distribution system.
- 6.44 MS noted this is a further issue that needs consideration alongside charging treatment, as ADS networks are not operated by LDSOs, complicating responsibility for losses.
- 6.45 LS noted that, in ADS arrangements, all exit points are registered in SVA or CVA, so losses are already calculated up to the ADS boundary point, leaving no obvious gap. Without a formal change, the only practical option appears to be compensating losses at the meter, though this is acknowledged as sub-optimal.



- 6.46 MS explained that a generic metering dispensation exists, introduced around 2011 to support competition. Since BSC change P453, if losses are immaterial, compensation may not be needed; however, where loss compensation is required, a dispensation is still necessary.
- 6.47 LS highlighted that in scenarios such as 33 kV to 11 kV step-downs, transformer losses are material, so loss compensation would clearly be required.
- 6.48 FW explained that, in practice, because agreement with the DNO on charging treatment for an ADS could not be reached, the site is currently being handled using difference metering, with losses addressed through complex calculations rather than ADS arrangements.
- 6.49 It was discussed that using complex/difference metering for an ADS feels inappropriate, as ADSs are intended to avoid the need for difference metering.
- 6.50 FW confirmed that, in principle, the site should qualify as an ADS, but the lack of clarity on Use of System charging treatment means it is currently being handled under full settlement (difference metering) instead.
- 6.51 This situation was acknowledged as unsatisfactory, with consensus that the issue is not technical feasibility but charging uncertainty, which is preventing ADS treatment.
- 6.52 MS noted that a solution is unlikely to be reached in-meeting but committed to feeding the issue into Exelon's Market Design team for further consideration.
- 6.53 LS cautioned that previous attempts (e.g., DCP 328 and its follow-up issue group) lost momentum and risked the same outcome if not carefully structured.
- 6.54 The Chair supported having a pre-CP discussion forum to review background, intent, and the most appropriate route forward.
- 6.55 LS additionally highlighted the need for legal clarity, particularly on the DCUSA interpretation previously discussed, as a prerequisite to progress.

Action 98/03	The Secretariat to approach the Panel to assess whether seeking legal advice from Gowling is appropriate at this stage.
Action 98/04	The Secretariat to create an issue group to take discussions on this topic forward.

## 7. Annual review of the Charging Methodologies

- 7.1 The Chair raised that an annual review of the Charging Methodologies is included in the April agenda.
- 7.2 The Chair queried whether the annual DCMDG discussion is required to explicitly demonstrate compliance with licence condition clause.
- 7.3 It was suggested that holding an explicit annual discussion provides a clear audit trail and reassurance that charging methodology issues remain on DNOs' radar, though views were mixed on whether this is strictly necessary given that changes can be raised at any time.
- 7.4 There was recognition that issues relating to charging methodologies are often complex and emerge throughout the year, rather than neatly at a single annual point.

- 7.5 JH noted that some issues are already being progressed elsewhere (e.g., FCP work) and therefore could be seen as already captured under the licence obligations. However, he agreed that issues can sometimes surface “cold” and supported the idea of a paper or structured prompt to help focus discussion.
- 7.6 The Chair agreed that an explicit, high-level annual review could be useful, acting as a formal opportunity to reference clause 13.2, even where issues are already being addressed through CPs or subgroups.
- 7.7 It was suggested that this review would be high-level and generic, signposting:
- 7.7.1 that issues can be raised at any point via CPs;
  - 7.7.2 what activity has occurred over the past year (e.g. FCP subgroups, live changes); and
  - 7.7.3 providing a prompt for any outstanding or emerging concerns.
- 7.8 There was a view that engagement with Ofgem might also be helpful to ensure shared understanding and assurance.

Action 98/05	<p>The Secretariat to create a paper for use with this agenda item, summarising:</p> <ul style="list-style-type: none"><li>• how the obligation is met in practice;</li><li>• relevant activity over the past year; and</li><li>• how parties can raise concerns or changes.</li></ul>
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## 8. Schedule 19

- 8.1 The Chair noted that the person who had raised this for discussion was no longer available on the call, due to known meeting clashes, so a post meeting update would be provided.

Action 98/06	The Secretariat reach out for an update and provide this to the DCMDG.
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## 9. Any Other Business

- 9.1 The Chair asked if there were any other items of business to discuss. No other items were discussed.

## 10. Agenda Items for the Next Meeting

- 10.1 The Chair explained that there we no specific items for the agenda, however the progress of the actions would be assessed and an agenda produced with these in mind.

## 11. DNO (“Distribution Network Operator”) Operational Matters

- 11.1 The Chair asked if there were any DNO Matters to be raised. No matters were raised.

## 12. Date of Next Meeting

- 12.1 The next DCMDG meeting will be held on 21 May 2026 via Microsoft Teams.

## 13. Attachments

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13.1 Attachment 1 – DCMDG Action Log & Forward Work Plan

13.2 Attachment 2 – Agenda Item 5 - ADS-UoS Presentation