




DCUSA Change Report		At what stage is this document in the process?
<h1>DCP 283</h1> <h2>The Calculation of Generation Credits in the CDCM</h2> <p><i>Raised as a Standard Change on 12 October 2016</i></p>	01 – Change Proposal	
	02 – Consultation	
	03 – Change Report	
	04 – Change Declaration	
<b>Purpose of Change Proposal:</b> <p>DCP 283 seeks to amend the calculation of credits for embedded generation to more closely reflect the benefits they bring to Distribution Network Operators.</p>		
	<p>This document is issued in accordance with Clause 11.20 of the DCUSA, and details DCP 283 – ‘The Calculation of Generation Credits in the CDCM’</p> <p>Parties are invited to consider the proposed amendment (Attachment 1) and submit their votes using the Voting form (Attachment 2) to <a href="mailto:dcusa@electralink.co.uk">dcusa@electralink.co.uk</a> by <b>26 January 2018</b></p> <p>The voting process for the proposed variation and the timetable of the progression of the Change Proposal (CP) through the DCUSA Change Control Process is set out in this document.</p> <p>If you have any questions about this paper or the DCUSA Change Process, please contact the DCUSA by email to <a href="mailto:dcusa@electralink.co.uk">dcusa@electralink.co.uk</a> or telephone 020 7432 3011.</p>	
	 <p>Parties Impacted: <b>Distribution Network Operators (DNOs), Independent Distribution Network Operators (IDNOs)Suppliers and Generators</b></p>	
	 <p>Impacted Clauses: Clause 31 - Schedule 16 (CDCM)</p>	

## Contents

<b>1 Summary</b>	<b>3</b>
<b>2 Governance</b>	<b>3</b>
<b>3 Why Change?</b>	<b>4</b>
<b>4 Solution</b>	<b>6</b>
<b>5 Relevant Objectives</b>	<b>18</b>
<b>6 Impacts &amp; Other Considerations</b>	<b>20</b>
<b>7 Implementation</b>	<b>24</b>
<b>8 Legal Text</b>	<b>24</b>
<b>9 Code Specific Matters</b>	<b>25</b>
<b>10 Recommendations</b>	<b>25</b>
<b>11 Attachments</b>	<b>25</b>



Any questions?

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## Timetable

The timetable for the progression of the CP is as follows:

### Change Proposal timetable

Activity	Date
Initial Assessment Report Approved by Panel	19 October 2016
First Consultation issued to Parties	14 March 2017
Second Consultation issued to Parties	01 September 2017
Change Report issued to Panel	13 December 2017
Change Report issued for Voting	05 January 2018
Party Voting Ends	26 January 2018
Change Declaration issued to Authority	30 January 2018
Authority Decision	6 March 2018
Proposed Implementation Date	01 April 2020

## 1 Summary

### What?

- 1.1 The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract between electricity Distributors, electricity Suppliers and large Generators. Parties to the DCUSA can raise Change Proposals (CPs) to amend the Agreement with the consent of other Parties and (where applicable) the Authority.

### Why?

- 1.2 DCP 283 has been raised by MVV Environment Services Limited and suggests changes that could improve the cost reflectivity of credits for embedded generators. More cost reflective credits for generators will place incentives on embedded generators that reflect the benefits they bring to network operators (more detail is included in the Change Proposal itself which can be found at Attachment 3).

### How?

- 1.3 The current arrangements reduce credits for embedded generation in line with the reduction in demand charges to reflect customer contributions demand customers have already made at the time of connection. The proposed solution is to exclude the customer contributions discount in the assessment of credits for embedded generators in the Common Distribution Charging Methodology (CDCM).
- 1.4 The CP also considered an amendment to the provision of credits at the voltage of connection to embedded generators, however during the development of the CP this was discounted by the Working Group.

## 2 Governance

### Justification for Part 1 Matter

- 2.1 DCP 283 is classified as a Part 1 matter and therefore will go to the Authority for determination after the voting process has completed.
- 2.2 This issue is considered a Part 1 Matter as it affects the level of charges for embedded generators and therefore impacts on competition for embedded generators as specified under DCUSA clause 9.4.2 (A).

## Requested Next Steps

- 2.3 The Panel consider that the Working Group have carried out the level of analysis required to enable Parties to understand the impact of the proposed amendment and to vote on DCP 283.
- 2.4 The DCUSA Panel recommends that this CP:
- Be issued to Parties for Voting.

## 3 Why Change?

### Background of DCP 283

- 3.1 The Proposer raised this CP to address two issues with the calculation of credits within the CDCM; namely the discounting of credits to take account of customer contributions and the principle of applying credits at the voltage of connection. These issues are considered separately below:

#### Credits at the voltage of connection

- 3.2 The principle applied within the CDCM is that credits are awarded to embedded generators for offsetting demand at voltage levels above but not including the voltage level of connection. For demand, costs are taken into account down to and including the voltage of connection. The rationale for awarding credits above the voltage level of connection was set down when the CDCM was developed and was justified as the benefit of reduced reinforcement was perceived to be higher up the network. The requirement was set out in appendix 2 of Ofgem's decision document 'delivering the electricity distribution structure of charges'<sup>1</sup> in 2008 which outlines the principles and assumptions to be used when setting out the CDCM. The relevant assumption is set out in 1.51 which states:

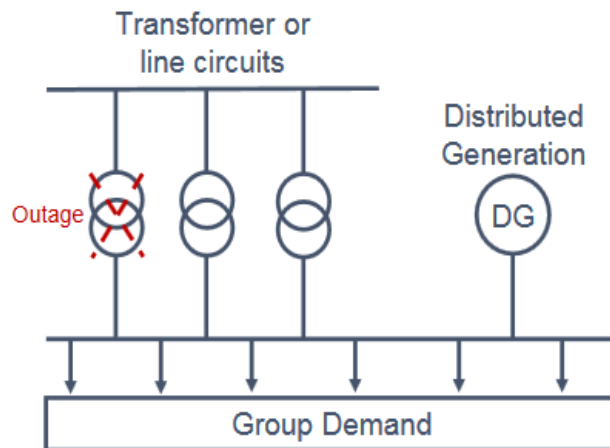
*"1.51. The network is assumed to be demand dominated. Credit will be provided for offsetting demand on the distribution network above the voltage of connection"*

- 3.3 The Ofgem decision is based on Engineering Recommendation (ER) P2/6 as supported by Engineering Technical Recommendation (ETR) 130 'Application Guide for Assessing the Capacity of Networks Containing Distributed Generation' and applies to both intermittent<sup>2</sup> and non-intermittent embedded generators.
- 3.4 The basic principle of ER P2/6 and ETR 130 is that embedded generators can offset the need for network capacity depending on the reliability of the generator and its setup. A simple example where an embedded generator offsets the need for a transformer is shown in the diagram below:

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<sup>1</sup> [Ofgem decision document - Delivering the electricity distribution structure of charges](#)

<sup>2</sup> Intermittent generation is defined as a generation plant where the energy source of the prime mover cannot be made available on demand, in accordance to the definitions in ER P2/6. These include wind, tidal, wave, photovoltaic and small hydro. The operator has little control over operating times.



- 3.5 The more reliable the generator, the more the DNO can rely on it for network planning purposes. ER P2/6 sets out the reliability factors (labelled “f” factors) for different types of embedded generator. Where a generator is intermittent, an additional persistence factor is also taken into account.
- 3.6 When assessing the ability of an embedded generator to offset network capacity, ER P2/6 refers to a demand group. The demand group is not specified at a network level and the assumption within the CDCM is that the benefit will be realised at the next voltage level up (e.g. for embedded generators connected to the low-voltage (LV) circuit level, the benefit will be realised at the low-voltage substation (LVS) transformer).

## High Voltage

- 3.7 At High Voltage (HV), DNOs typically exclude HV connected embedded generators when considering the network required to meet the demand for a new customer. However, at the Extra High Voltage (EHV)/HV substation, they take account of any embedded generators and consequently less capacity may be required at the substation and voltage levels above. This principle suggests that the current principle within the CDCM of awarding credits for the voltage levels above but not including the voltage of connection is correct as the benefit to the DNO is only realised at higher voltage levels. The Proposer is not suggesting an amendment to the methodology for credits for HV connected embedded generators.

## Low Voltage Substation

- 3.8 Embedded generators who connect directly at LVS do not currently receive a credit for avoiding the use of the HV/LV substation. However, the principle that the benefit is realised at the substation where the capacity can be reduced holds true even though the embedded generator is connected directly to a substation, provided other customers are also connected to that substation and so the power output from the generator can flow to demand customers without using the HV/LV transformer. It is therefore appropriate that, if LVS connected embedded generators are predominantly at shared substations, LVS connected embedded generators should receive credits at the voltage of connection. However, as the embedded generator will only benefit the DNO if it

can be relied on, the Proposer is suggesting extending the credits to the voltage of connection for non-intermittent LVS connected embedded generators only.

### **Low Voltage**

3.9 Embedded generators connected to the LV network are not particularly visible to DNOs. When a DNO is planning the LV network, they are more likely to assess the maximum demand at the local substation with some consideration of any large embedded generators that may be connected. At the LV network level, the presence of embedded generators will be more diverse and therefore the Proposer believes some of the benefits will be realised at the level of connection in addition to the higher voltage levels. The Proposer wishes to award partial credits at the voltage of connection for LV connected embedded generators by allocating a proportion of the demand costs at the voltage of connection as a credit to non-intermittent LV connected embedded generators. The Proposer suggests a 75% sharing factor for the proportion of the LV demand charge that should be allocated to LV connected embedded generators, but suggests that this value would need further consideration by the Working Group.

### **Treatment of customer contributions**

3.10 Within the CDCM, demand charges are reduced by customer contributions to take account of amounts paid up front when customers connect. Credits for embedded generators are calculated as the inverse of demand charges after customer contributions are applied. Hence, the application of customer contributions reduces the level of credits below that which would have been derived had customer contributions not been applied.

3.11 It is the Proposer's view that when a generator connects to the network, one of the benefits that is realised by the DNO is a reduced flow on the local network. This allows further demand customers to connect without the need for reinforcement and therefore demand customers will need to make less or no customer contribution when they connect. Consequently, applying the customer contributions to credits for embedded generators reduces the cost reflectiveness of the credit that is provided under the CDCM.

## **4 Solution**

### **DCP 283 Working Group Assessment**

4.1 The DCUSA Panel established a Working Group to assess DCP 283. This Working Group consists of DNO, Supplier, National Grid, trade association, consultancy and Ofgem representatives. Meetings were held in open session and the minutes and papers of each meeting are available on the DCUSA website – [www.dcusa.co.uk](http://www.dcusa.co.uk).

### **Request for Information and First Consultation**

4.2 To assist the Working Group in assessing the CP, a Request for Information (RFI) was issued to DNOs. The purpose of the RFI was to help establish how DNOs plan their network and the extent

to which they rely on embedded generators from a planning perspective. The RFI and associated responses and outcomes is detailed within Attachment 8.

4.3 The Working Group reviewed the responses and concluded that:

- DNOs are operating to ER P2/6 standard or higher;
- no amendments to the methodology are required for credits at the HV level;
- the majority of LVS connected generators have sole use substations and as such the Working Group decided it was not appropriate to award credits at the voltage of connection to generators connected at the LVS network level; and
- DNOs can accurately measure demand at the LV substation but not necessarily further down the LV network and as such DNOs may receive a benefit to their LV networks when LV connected embedded generation connects, however, this is largely unknown.

4.4 Based on the RFI responses and to aid the further development of the solution for DCP 283, the Working Group issued a consultation to Parties. The responses and subsequent review of responses by the Working Group is detailed within Attachment 4, and an overview of the conclusions drawn from the review is outlined below.

### Credits at the voltage of connection

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4.5 The first consultation included a series of questions on whether credits should be awarded at each voltage level of connection.

#### High Voltage

4.6 The Proposer and Working Group did not suggest any amendments to the methodology for credits for HV connected embedded generators. The Working Group noted that all respondents to the consultation agreed with the view of the Working Group and as such no amendments will be made.

#### Low Voltage Substation

4.7 The Proposer initially believed that where an embedded generator connects directly to a HV/LV substation, the saving in reinforcement costs are the same as that achieved by a LV connected embedded generator. The Proposer therefore initially suggested that it is appropriate that credits for LVS connected generators should include deferred reinforcement costs at the LVS voltage level as the generator is effectively connecting at LV, provided other customers are also connected to the same substation and so the power output from the generator can flow to demand customers without using the HV/LV transformer. Using the RFI data the Working Group concluded that the majority of LVS connected embedded generators have sole use HV/LV substations, so decided it was not appropriate to award credits at the voltage of connection to LVS connected embedded generators. The Working Group noted that all respondents to the consultation agreed that LVS connected embedded generators should not be awarded credits at the voltage of connection and as such no amendments will be made.



## Low Voltage

- 4.8 The Working Group proposed arguments for and against the awarding of credits to LV connected non-intermittent embedded generators at the voltage of connection. Views from industry were sought on whether they believed that credits should be awarded to non-intermittent LV connected embedded generators at the voltage of connection. Respondents' views to the consultation were mixed, and the Working Group agreed that more work would be required to define and proceed with a solution.
- 4.9 The Proposer subsequently raised concerns that continuing to focus on the issue of awarding credits to LV connected non-intermittent embedded generators at the voltage of connection is likely to result in a delay to the CP. Additionally, the Proposer noted concerns that the process is unlikely to yield a sufficiently high degree of evidence to enable this part of the CP to progress. Consequently, the Proposer agreed that it would be sensible for the Working Group to proceed with the customer contributions element of the CP only, and the Working Group supported this decision. There were no Working Group members who wished to sponsor the credits at the voltage of connection section of the CP via an alternative proposal. The Working Group agreed that the second consultation would include a question regarding the removal of credits at the voltage of connection from the CP.

## Treatment of customer contributions

- 4.10 The Proposer believes that when an embedded generator connects to the DNO network, one of the benefits that is realised by the DNO is a reduced flow on the local network and at higher voltage levels. The Proposer believes that this allows further demand customers to connect without the need for reinforcement and therefore demand customers will need to make less or no customer contribution when they connect. Consequently, the Proposer believes that applying the customer contributions to credits for embedded generators reduces the cost reflectiveness of the credit that is provided under the CDCM.
- 4.11 The Working Group noted that credits are awarded to embedded generators to reflect the reduction in the DNOs future costs that is expected due to the presence of embedded generators. However not all members of the Working Group agreed with the Proposer's assertion that customer contributions will necessarily be reduced by the presence of embedded generators. However, the Proposer's view is that the benefit would still be realised at higher voltage levels and that this element of the CP, on a standalone basis, would only remove customer contributions from the calculation of credits for embedded generators at higher voltage levels.
- 4.12 The first consultation sought views on whether industry believes a cost saving occurs when embedded generators connect which creates a more resilient network and reduces the need for new demand customers to pay contributions. The views were mixed and depended upon various scenarios (e.g. it is unlikely to be the case in localised generated dominated areas).

One respondent stated that:

*"We have seen no evidence that the cost saving which embedded generators are being perceived to create is more accurately represented by the removal of customer*



*contributions. Whilst we acknowledge that, when viewed in aggregate, embedded generators do create a more resilient network, we believe they are appropriately remunerated for this benefit through existing Use of System credits.”*

The counter view stated by another respondent was:

*“At present, embedded generation receive a credit for the reduced reinforcement costs incurred on behalf of DNOs. The amount of cost the DNO incurs is dependent on the apportionment rules, so if more of these costs were allocated to the DNO, the generation credits would be larger. However, the saving still existing, whether it accrues to the DNO or customer and therefore we believe that customer contributions should be ignored when deriving generation credits.”*

- 4.13 It was evident from the consultation responses received that further work was required in this area. The Working Group noted the need to review the customer contribution section of the CP to ensure that a case has been made for the change to the treatment of customer contributions, and that specific examples are provided for clarity.

## Working Group Assessment Following First Consultation

### Credits at the voltage of connection

- 4.14 As the application of credits at the voltage of connection was no longer being considered by the Working Group, the Working Group focussed entirely on the customer contributions element of the proposal.

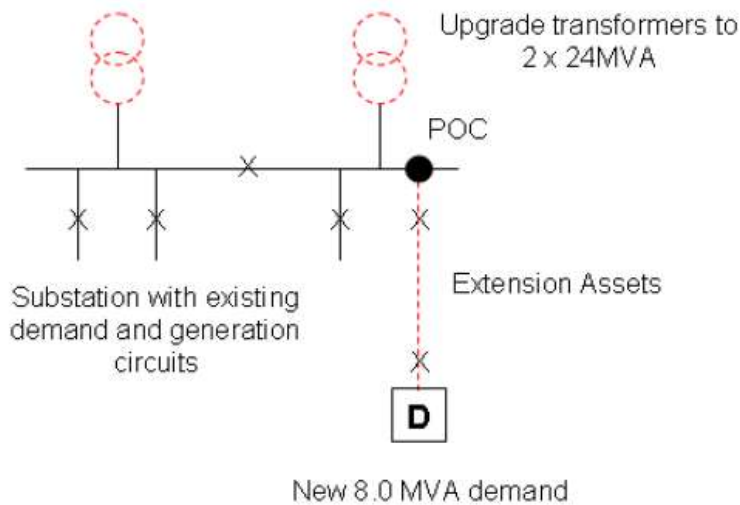
### Treatment of Customer Contributions

- 4.15 The Working Group sought to define customer contributions and then examined specific examples with regards to the discounting of credits to take account of customer contributions. The resulting work is set out within the paragraphs below.
- 4.16 Customer contributions are the amounts customers pay when they connect to the distribution network. When customers connect, the DNO will determine what assets need building/ reinforcing and this cost is split between the customer and the DNO. The apportionment rules are set out in the Common Connection Charging Methodology (CCCM) in Schedule 22 of DCUSA. Within the CDCM, one of the inputs that DNOs are required to determine is the ‘Customer Contributions Under Current Connection Charging Methodology’. Each DNO is required to populate a table with a percentage at each voltage level for customers connected at each voltage level. The percentage inputs are intended to represent the average contribution to assets at that voltage level a customer connecting will have contributed at the time of connection.
- 4.17 Customers tend to pay most of the cost of connecting at the voltage of connection. At voltage levels above the voltage of connection, the DNO pays a greater proportion which is then recovered through Use of System charges to all customers. This is to ensure connection charges are fair (e.g. a domestic customer shouldn’t have to pay for an upgrade to a primary substation). The average contribution (as determined by the DNO) can be seen in the values used in the CDCM, table 1060. Below is an extract from the Electricity North West Limited (ENWL) April 2018 customer contributions input table (132/HV assets removed for clarity):

	Assets 132kV	Assets 132kV/EHV	Assets EHV	Assets EHV/HV	Assets HV	Assets HV/LV	Assets LV circuits
LV network					30.00%	30.00%	97.00%
LV substation					30.00%	97.00%	
HV network				57.00%	91.00%		
HV substation			57.00%	92.00%			

- 4.18 This data implies that an average ENWL customer connecting to the LV network, will contribute 97% towards any costs associated with the LV network and 30% towards any costs associated with the HV/LV substation and HV network.
- 4.19 Within the CDCM, the 500MW model costs form the basis of the asset costs element of the unit rate charges for each tariff. The unit rate yardstick charge in respect of asset costs (not operating costs) are discounted to take account of the customer contributions already deemed to have been made. So, for a LV connected customer in ENWL's area, the asset costs that form part of their unit rate are discounted by 97% for the LV network level, and 30% for the HV/LV and HV network levels.
- 4.20 This is a reasonable approach, as demand customers should not pay for the same asset twice. Any resulting revenue shortfall is recovered through revenue matching.
- 4.21 It should be noted that the 500MW model represents shared use assets whilst the service models represent sole use assets as referenced in the CDCM user manual. This is an important distinction as the customer contribution discounts are applied to the 500MW model only and therefore to the shared use assets, not sole use assets. No capital cost is recovered in respect of service model assets, so the CDCM effectively assumes the cost of service model assets has been recovered in full at the time of connection. The service model cost is used as a proxy for determining the operation and maintenance costs on service model assets which are recovered through the CDCM.
- 4.22 The cost of connecting new customers can be split into two cost elements as follows:
- Extension assets "are assets installed to connect a party or parties to the existing distribution network but which exclude Reinforcement assets". Customers fully contribute to the cost of these assets through the connection charge.
  - Reinforcement assets are "assets installed that add capacity (network or fault level) to the existing shared use Distribution System". Reinforcement assets are subject to the apportionment rules contained within the CCCM (DCUSA Schedule 22) and as such are partly funded by the customer, and partly funded by the DNO and subsequently recovered through Use of System charges.

4.23 An example connection and the associated costs are contained below. This is for a new connection of an 8MVA industrial premises at HV (example 12 from the CCCM):



4.24 The costs associated for this connection are shown below. The customer contributes £500k towards the total reinforcement cost of £1,500k, which equates to c33% and the full extension asset costs of £130k.

#### Reinforcement:

	Cost	Apportionment	Customer Contribution
<b>Non-Contestable Work</b>			
Installation of 2 x 24 MVA 33/11 kV transformers	£ 1,500,000	$8.0 / 24.0 \times 100\% = 33.3\%$	£ 500,000
<b>Total Reinforcement Cost</b>	£ 1,500,000		£ 500,000

#### Extension Assets:

	Cost	Apportionment	Customer Contribution
<b>Contestable Work</b>			
Installation of 750m 11kV cable	£ 75,000	n/a	£ 75,000
Installation of 11kV metering circuit breaker	£ 50,000	n/a	£ 50,000
<b>Non-Contestable Work</b>			
Joints to 11kV network	£ 5,000	n/a	£ 5,000
<b>Total Extension Asset Cost</b>	£ 130,000		£ 130,000

### **Extension Assets**

- 4.25 Extension asset costs are the costs associated with connecting a site to the shared use network. For example, when a housing estate connects with its own HV/LV substation, all of the new assets are defined as extension assets. However, once connected, some of the extension assets can be defined as sole use (i.e. those connecting an individual dwelling) and some as shared use (i.e. those supplying multiple dwellings in the estate).
- 4.26 The existing CDCM methodology reduces asset costs by the level of customer contributions made by demand customers. The Proposer asserts that embedded generators may reduce the extension assets required for a new connection and that they should therefore benefit from this. For example, where a new connection is developed that incorporates an embedded generator, the extension assets required may be reduced. This may be through embedded generators connected directly at individual premises or directly to the new distribution network. In addition, once the extension assets are absorbed into the shared use network, the connection of an embedded generator potentially enables future demand connections without more infrastructure investment. Consequently, it is possible that the embedded generator can be viewed as providing an incremental benefit to the network to which it is connected and it is appropriate that that network should be valued on a standalone basis (i.e. not after removing customer contributions).

### **Reinforcement Assets**

- 4.27 Reinforcement assets are defined in the CCCM as assets installed that add capacity (network or fault level) to the existing shared use network. In the example provided above, the connection of the new customer leads to an upgrade of the existing transformer assets to ensure the capacity is large enough for the additional demand.
- 4.28 Under the network planning regulations used by the DNOs (ER P2/6), DNOs can rely on embedded generators to provide network security. This enables embedded generators to reduce reinforcement costs for DNOs and this principle forms the basis for the awarding of credits within the CDCM. In practice, this benefit occurs due to embedded generators directly offsetting network reinforcement or by offsetting demand at lower voltage levels and reducing the amount of visible demand, and therefore the assets required, at higher voltage levels.

### **Conclusions**

- 4.29 Credits for embedded generators are based on the negative of demand costs at voltage levels above the level of connection. Consequently, the asset costs that form part of the demand charge (and therefore the credit to embedded generators) are reduced to take account of customer contributions.
- 4.30 DCP 283 raises the issue of whether it is appropriate to discount credits for embedded generators for customer contributions in the same way as demand customers. The CDCM is a forward-looking model and connecting embedded generators can enable future demand customers to connect without the customer or DNO incurring significant reinforcement.
- 4.31 In the example above, embedded generators directly connected into the primary substation or lower down the network and offsetting the load at the primary substation, potentially remove the need for reinforcement. The saving achieved is the total reinforcement cost, not the reinforcement

cost less the customer contribution. In this example, it would therefore be appropriate to determine the credit for the embedded generator based on the full cost before the customer contribution is deducted.

- 4.32 The 500MW model represents the shared use assets on the distribution network. Embedded generators connect to the shared use network and therefore reduce costs associated with the 500MW model. Customer contributions reduce the value of the 500MW model when it is moved to a unit basis and applies it to both charges for demand and credits for embedded generators. This may be appropriate for demand, but for embedded generators it reduces the underlying asset costs that the embedded generator can offset. This holds true for offsetting both reinforcement costs on the existing network and also for extension assets where savings potentially accrue when embedded generators are incorporated into the design. In addition, once extension assets become part of the shared use network, new embedded generators connecting into this part of the network enable future demand customers to connect at lower cost.
- 4.33 One Working Group member questioned the validity of this conclusion, on the basis that it assumes the connection of an embedded generator is always of value to the DNO. There are instances across the DNO networks where embedded generators in certain areas do not provide benefit to the local network, but in fact drive reinforcement cost on the local network. Whilst the benefit of the connection of the first embedded generator to a certain local network may be more accurately reflected by the removal of customer contributions from the calculation of credits, the marginal benefit of further embedded generators connecting will be lower as more embedded generators connect.
- 4.34 Continuing the example used above, the first generator connecting may offset the need for reinforcement at the HV/LV substation if further demand customers were to connect. However, the connection of a second embedded generator would not have such an impact (as the need for reinforcement has already been offset); hence it cannot be assumed that all embedded generators provide a full benefit all of the time.
- 4.35 The Working Group member also questioned whether there is a more fundamental issue with the way in which the CDCM values embedded generators, and suggested that a wider review may be necessary, as opposed to piecemeal changes such as this.

#### **Generated dominated areas**

- 4.36 The rationale of awarding credits to embedded generators is based on the principle that distribution networks are demand dominated. Where networks are demand dominated, future network costs are driven by increases in demand and embedded generators reduce the level of demand and therefore reduce the need for investment in additional assets.
- 4.37 Since the introduction of the CDCM, concern has been expressed that embedded generators may in some areas be the driver of future network costs. This is because the increase in the connection of embedded generators has led to some areas of the distribution networks becoming generation dominated. Where this is the case, additional embedded generators connecting to the same part of the network may be driving additional costs for the DNO. This issue was looked at under DCP137, which proposed reducing or removing credits to any HV connected embedded generators that

were connected to a generation dominated primary substation. This proposal was rejected by Ofgem in February 2015 citing “concern about the impact that the proposed change may have on further growth of renewable generation, and the balance between generation and demand growth, on distribution networks”.

#### **Active network management schemes**

- 4.38 Due to the increasing number of embedded generators connecting to DNO networks, all bar one DNO currently offer Active Network Management schemes (ANMs), with the other being able to do so within 18-24 months. Work in this area is ongoing through the Energy Networks Association (ENA) Open Networks Project and is being considered as part of the Ofgem Charging Futures work. These schemes enable embedded generators to connect under a managed connection which gives the DNO the right to curtail the output of the generator under certain network conditions. This enables the embedded generator to connect without incurring large upfront connection charges and to be able to connect much quicker as there is no requirement to wait for time consuming reinforcement to be completed. This approach also benefits the DNO who may also have been required to fund part of the connection cost through the apportionment rules.
- 4.39 The uptake of managed connections means that the emergence of an increasing number of generation dominated areas has not added significantly to DNO network costs. Whilst it is still beneficial to have embedded generators in these areas (as they effectively increase the capacity of the network and enable more demand customers to connect without driving significant reinforcement) the incremental benefit will decrease as each subsequent generator connects.

### **Other Considerations**

#### **DCP 243 ‘Treatment of Customer Contributions in the CDCM’**

- 4.40 The Working Group agreed that it was worth monitoring DCP 243 as it is seeking to standardise customer contributions.
- 4.41 It is the belief of DCP 283 Working Group members that both DCP 243 and DCP 283 are able to progress independently, with DCP 243 focussing on updating input values for use in the CDCM which will use up to date source data without fundamentally amending the principles by which they are determined, whereas DCP 283 is looking to amend the way in which the input values are used in the CDCM model. DCP 243 has just been consulted on and the Working Group will be reviewing responses shortly.

### **Second Consultation - Questions and Responses**

- 4.42 A second consultation was issued to DCUSA Parties on 01 September 2017 to consider the de-scoping of awarding credits at LV and whether customer contributions should be excluded from the assessment of credits for embedded generators in the CDCM. A summary of the responses received, and the Working Group’s conclusions are set out below. The full set of responses and the Working Group’s comments are provided in Attachment 5.



### Question 1: Do you support the de-scoping of 'awarding credits to LV connected non-intermittent embedded generators at the voltage of connection' from the proposal?

- 4.43 The Working Group noted that all bar one respondent agreed with the view of the Working Group to de-scope 'awarding credits to LV connected non-intermittent embedded generators at the voltage of connection' from the proposal.
- 4.44 The Working Group agreed to reflect the response of the Party which disagreed with de-scoping 'awarding credits to LV connected non-intermittent embedded generators at the voltage of connection' from the proposal although the decision of the Working Group was to de-scope this element from the change proposal. The response is set out below:

*"We feel the Working Group has done some good work on this area, and to de-scope this issue now would result in the wasting of the time and effort which has already gone into this. Whilst we have made it clear in previous responses that we do not believe credits should be awarded, the Working Group should continue with the work done to date, and reach a conclusion on this area to achieve some certainty going forward. This could then inform any wider review of distribution charges as we transition to a smarter, more flexible energy system."*

### Question 2: Should the customer contributions discount be excluded in the assessment of credits for embedded generators in the CDCM?

- 4.45 The Working Group noted that the responses are 6/3 against excluding the customer contributions discount from the assessment of credits for embedded generators and noted respondents concerns around the level of credits compared to the benefits embedded generators bring to networks.
- 4.46 The Working Group agreed to highlight the views of one respondent which highlighted a question around whether UoS credits be used and/or instead of a connections cost benefits in the assessment of credits for embedded generators. The portion of the response which relates to the aforementioned question is set out below:

*"We believe that paragraph 3.3 of the consultation document outlines an argument that is inconsistent with the fundamental principles of the model. The credits given to generators in the methodology are based on the principle of the saving resulting from offsetting demand related costs. If demand customers make contributions that are taken into account in the calculation of their tariffs then the same contributions should be taken into account in the calculation of generator tariffs. The proposed change would result in generators receiving larger credits than the equivalent element of the demand tariffs."*

Note: The model referred to in the above response is the CDCM model.



The counter view by one respondent was:

*“We recognise that the first generator that connects is the most valuable because it removes the immediate need to reinforce. However, subsequent generators connecting to the same network still add value. The connecting generation frees up capacity on existing assets, which can then be used by existing demand users to increase their consumption or for new demand customers to connect without driving reinforcement and therefore incurring high connection costs. All generation adds value in this way, except when connecting to a generation dominated area”.*

### Question 3: Do you believe that a wider review of credits for embedded generators is required before changes such as this can be progressed?

4.47 The Working Group note that the responses are 5/4 in favour of a wider review of credits for embedded generators before changes such as this can be progressed. The Working Group have drawn out the comments/themes from the responses to highlight a balanced view. Responses for and against a wider review are set out below:

*“We are not against a wider review, but this change seems sensible in itself and should be made. There is no guarantee of a further review.”*

*“This particular change does not require a wider review of credits for it to progress as the change proposal is now very specific. Although a wider review of credits for embedded generators should be progressed within the charging reviews.”*

*“We believe the current method of calculating credits for embedded generators based simply on the negative of demand charges is outdated, hence why it is being looked at by the ongoing CDCM review. We do not think that changes such as this are appropriate until a more fundamental review has been undertaken, resulting in a more transparent and cost-reflective method of calculating generation credits which will then be subject to change through open governance.”*

*“We are supportive of a wider review. This change looks at one element within the methodology without considering whether a change of this nature is appropriate. This wider review we feel will take place as part of the work being considered under the Charging Futures Forum (CFF)”*

### Question 4: Do you consider that the proposal better facilitates the DCUSA Charging Objectives? Please give supporting reasons.

4.48 The Working Group note that the responses are 5/3 against and 1 undecided as to whether DCP 283 better facilitates the DCUSA Charging Objectives. It is also noted that only qualitative information was given in response to the question and that no quantitative information was provided.

4.49 Of the three respondents that considered DCP 283 better facilitates the DCUSA Charging Objectives, two cited Charging Objectives 2 and 3 were better facilitated which is in line with the Proposer’s view. The remaining respondents who considered DCP 283 better facilitates the

DCUSA Charging Objectives noted that in their view, providing correct incentives to embedded generators is more economically efficient and thus makes for more cost reflective charging. One respondent stated:

*“the change will result in a more cost reflective charging regime which promotes competition and leads to the efficient scheduling of plant. It therefore better meets charging objectives two and three:*

- 4.50 Of the five respondents that considered DCP 283 does not better facilitates the DCUSA Charging Objectives, two respondents didn't provide a view as to which of the objectives are not better facilitated by DCP 283 with one citing that as they don't support the change they don't believe it better facilitates the DCUSA Charging Objectives. One respondent noted their view that the change would result in a detrimental impact against Charging Objective three and detailed the following reasoning:

*“We have seen no evidence that this change will result in more cost-reflective generation credits, and as a result the corresponding increase in demand tariffs is unjustified and less cost-reflective than the existing demand tariffs.”*

- 4.51 Two respondents referred back to their answers to Question 2. The relevant text from one respondents answer to question two is detailed below:

*“Our view is that in the case of generators reducing customer contributions then the customer contribution percentage in the model already reflects the overall extent to which this occurs. The CDCM is an averaging methodology that produces charges that are uniform across the DNO distribution area. We do not believe adjusting customer contribution discounts in the calculation of generator tariffs below the region-wide average of customer contributions would improve cost reflectivity given the underlying principles of the model.”*

*“It may be the proposer's view that the current methodology's calculation of long run incremental cost understates the replacement costs that DNOs will ultimately incur for assets on its network, and therefore also understates the benefits provided by embedded generators. However, the proposed solution does not address this issue directly, and instead distorts the calculation of the benefits of generators on network construction or expansion investment.”*

**Question 5: Are you supportive of the proposed implementation date of 1 April 2020? Or is your preference 1 April 2019 and if so how can this be achieved? Please provide your rationale for either option.**

- 4.52 The Working Group noted that the majority of responses were in favour of a 01 April 2020 implementation date. The Working Group agreed that the implementation of DCP 283 should be pushed back to 01 April 2020.

#### **Question 6: Do you have any comments on the proposed legal text?**

- 4.53 The Working Group noted that there were no comments from respondents with regards to the legal text and the Working Group agreed that the text produced by the group can be used as the version provided to the legal advisor and included in the Change Report.

#### **Question 7: Do you have any other comments on DCP 283?**

- 4.54 The Working Group noted that only one respondent had any further comments and that the comment reiterated a response to Question 3 which the Working Group picked up whilst reviewing the responses to Question 3 above.

#### **Question 8: Are you aware of any wider industry developments that may impact upon or be impacted by this CP?**

- 4.55 The Working Group noted that the responses have highlighted respondents' views that the CDCM/EDCM review and the Charging Futures Forum (CFF) work may impact this change.

#### **Question 9: Are there any alternative solutions or unintended consequences that should be considered by the Working Group?**

- 4.56 The Working Group noted that only one respondent had provided details of a potential unintended consequence and that the response reiterated a response to an earlier question regarding the reinforcement costs to the network for generation dominated areas. The Working Group acknowledge that this is a concern and the Working Group have given consideration to this area in paragraphs 4.36 and 4.37 above.

### **Working Group Conclusions**

- 4.57 The Working Group agreed that no further work apart from reaching a decision on the DCUSA Charging Objectives was required on DCP 283. This is covered under section 5.

## **5 Relevant Objectives**

### **Assessment Against the DCUSA Objectives**

- 5.1 For a DCUSA CP to be approved it must be demonstrated that it better meets the DCUSA Objectives. The Working Group sought Parties views on which of the DCUSA Charging Objectives are better facilitated by this change.
- 5.2 The majority of the Working Group believe that DCP 283 does not better facilitate the DCUSA Charging Objectives. The Working Group specifically discussed which objectives and their views as to why. Of the seven members who were asked for their views, it was noted that five agreed that Charging Objectives two and three are not better facilitated by DCP 283.

5.3 The Working Group considers that the following DCUSA Charging Objectives are in scope of DCP 283 and commentary detailing the rationale for and against each are set out in the table below.

Impact of the Change Proposal on the Relevant Objectives:	
Relevant Objective	Identified impacts and rationale for and against
Charging Objective Two - that compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)	<p><b>Positive</b></p> <p>“More cost reflective tariffs will provide a more accurate price signal which will result in a more efficient dispatch of plant and the siting of plant within the distribution network. Both of these will result in the promotion of effective competition in generation.”</p> <p><b>Negative</b></p> <p>“It may be the proposer’s view that the current methodology’s calculation of long run incremental cost understates the replacement costs that DNOs will ultimately incur for assets on its network, and therefore also understates the benefits provided by embedded generators. However, the proposed solution does not address this issue directly, and instead distorts the calculation of the benefits of generators on network construction or expansion investment.”</p>
Charging Objective Three - that compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business.	<p><b>Positive</b></p> <p>“It increases the cost reflectivity of tariffs within the CDCM by awarding credits to embedded generators that more closely reflect the benefits they bring to DNOs and thereby encourages the development of efficient, co-ordinated and economical distribution networks.”</p> <p><b>Negative</b></p> <p>“Our view is that in the case of generators reducing customer contributions then the customer contribution percentage in the model already reflects the overall extent to which this occurs. The CDCM is an averaging methodology that produces charges that are uniform across the DNO distribution area. We do not believe adjusting customer contribution discounts in the calculation of generator tariffs below the region-wide average of customer contributions would improve cost reflectivity given the underlying principles of the model.”</p> <p>“We have seen no evidence that this change will result in more cost-reflective generation credits, and as a result the corresponding increase in demand tariffs is unjustified and less cost-reflective than the existing demand tariffs.”</p>

- 5.4 The Proposer believes that Charging Objectives two and three are better facilitated by DCP 283. The reasoning behind this is set out in the table above and in the CP form (Attachment 3).
- 5.5 As a result of reviewing responses to the first consultation, the Working Group identified there was some support for Charging Objectives two and three; however, there was a majority view that further issues needed to be addressed and the Working Group agreed to undertake work on developing these.
- 5.6 As noted in paragraphs 4.48 and 4.49 above, responses to the second consultation were 5/3 against and 1 undecided as to whether DCP 283 better facilitates the DCUSA Charging Objectives. Of those that believe the DCUSA Objectives are generally better facilitated by DCP 283, Charging Objectives two and three were identified as the relevant objectives.

## 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 The Working Group does not consider at this stage, there to be any cross-code impact.
- 6.2 The Working Group have highlighted the interactions between the CDCM/EDCM review groups work and DCP 283. The CDCM/EDCM review was split into two stages. Stage One captured the issues and prioritised the areas that could be taken forward into Stage Two. These were:
- a) Type of Costing Model.
  - b) Tariff Structures.
  - c) Licenced Distribution Network Operator (LDNO) Charging Arrangements.
  - d) New Products (e.g. Storage).
  - e) Combining the CDCM and EDCM Methodologies.
- 6.3 The Working Group also wish to highlight that in parallel with this review, Ofgem issued a consultation on a Targeted Charging Review (TCR) and launched a Significant Code Review (SCR) on the 04 August 2017.
- 6.4 One of the outcomes from this review is that Ofgem has set up the CFF. The CDCM/EDCM Review Groups report was therefore submitted to Ofgem in July 2017 and it is expected that this group will then direct the next stage by providing some guidance on areas to be progressed.
- 6.5 At this stage, the development of the CDCM/EDCM review is at a high level and does include generation. The SCR whilst establishing the CFF is also looking at residual charges which does not impact this change proposal.

## Consumer Impacts

- 6.6 The Working Group considered that this change would benefit from Parties being able to understand its impact in a modified CDCM model with impact estimates. The DCP 283 modelling documentation acts as Attachment 6. The CDCM model has been modified to exclude the customer contributions discount in the assessment of credits for embedded generators in the CDCM. This has been achieved by removing all generation tariff data from Table 2801 and Table 2803 from the CDCM.
- 6.7 DNO Working Group members have successfully populated the DCP 283 CDCM model and replicated the expected resulting outputs from this modified model.

### Impact Assessment

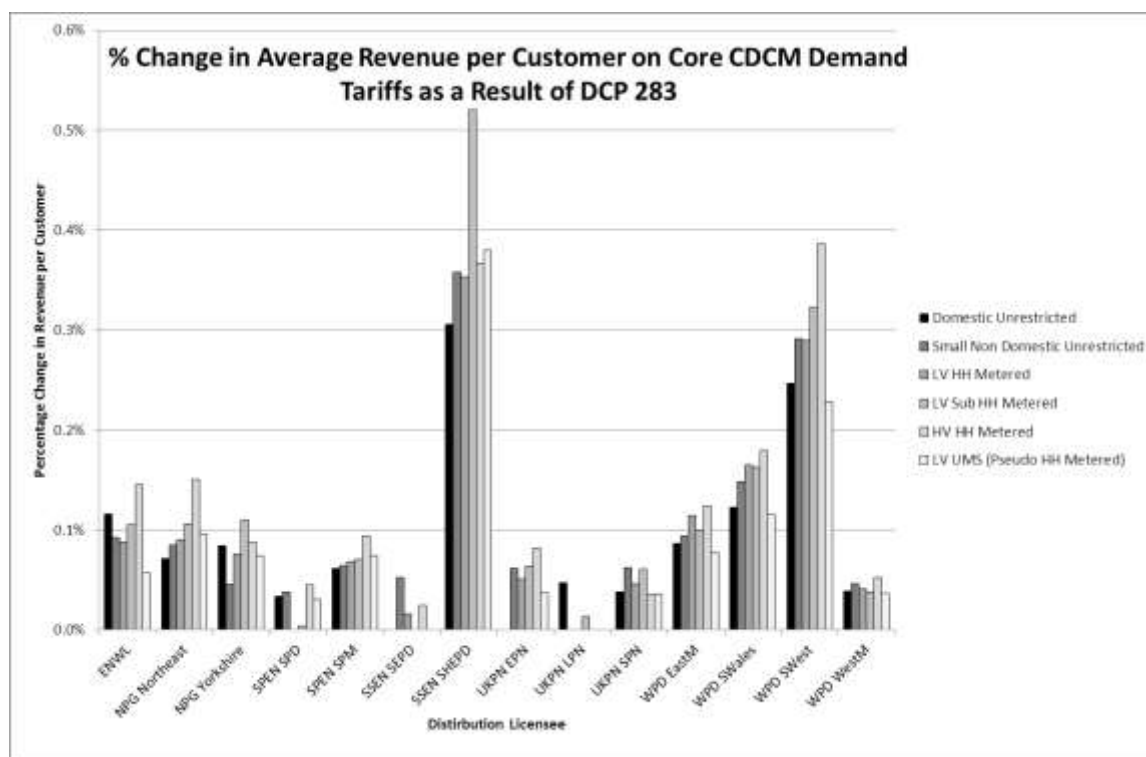
- 6.8 The Impact Assessment documentation acts as Attachment 7 to this Change Report. The files in Appendix 1 set out the impact of DCP 283 on individual tariffs for each DNO area. This covers the impact on tariff components (unit rates, fixed charges, capacity charges etc), the impact on total forecast revenue from each tariff (split by individual elements), and the impact on forecast revenue from each tariff expressed in p/kWh. This analysis has been based on the (2018/19) methodology.
- 6.9 Appendix 2 to Attachment 7 sets out the impact of DCP 283 as a set of charts showing the impact of DCP 283 on forecast revenue from each tariff expressed in £/MPAN/year.
- 6.10 Appendix 3 has been pulled together by a Working Group member at the request of the Working Group. It summarises the impact on core customer groups and includes the data behind the charts shown below.
- 6.11 Removing the application of customer contributions from the calculation of credits for embedded generators increases generation credits for the majority of embedded generators, with a consequential increase in charges for most demand customers.
- 6.12 The increase in charges for demand customers is relatively small, with all demand customers seeing an increase of less than 1%, as can be seen in table 1 below which shows the minimum, maximum and average percentage change for core demand customer groups across the 14 DNO licensees. The impact varies by licensee depending on the level of embedded generation connected to each licensee's network – areas with high levels of embedded generation connected see a more significant impact than those with lower embedded generation connected. As can be seen from the table below, the impact in some areas is sufficiently small that the impact on core customer groups is absorbed within tariff rounding (unit rates being rounded to three decimal places of a penny, and fixed and capacity charges to two decimal places of a penny).



% Change in Average Charge per Customer	GB Min	GB Average	GB Max
Domestic Unrestricted	0.00%	0.09%	0.31%
Small Non Domestic Unrestricted	0.00%	0.10%	0.36%
LV HH Metered	0.00%	0.10%	0.35%
LV Sub HH Metered	0.00%	0.12%	0.52%
HV HH Metered	0.00%	0.13%	0.39%
LV UMS (Pseudo HH Metered)	0.00%	0.09%	0.38%

**Table 1 - Impact on demand customers of removing customer contribution from the calculation of credits for embedded generators**

6.13 Figure 1 shows the spread of impact on demand customers across DNO licensees. As expected, the biggest impact is seen in the North of Scotland where distribution connected wind generation is prevalent and in the South West where distribution connected solar generation is prevalent.



**Figure 1 - Spread of impacts of DCP 283 on demand customers across DNO licensees**

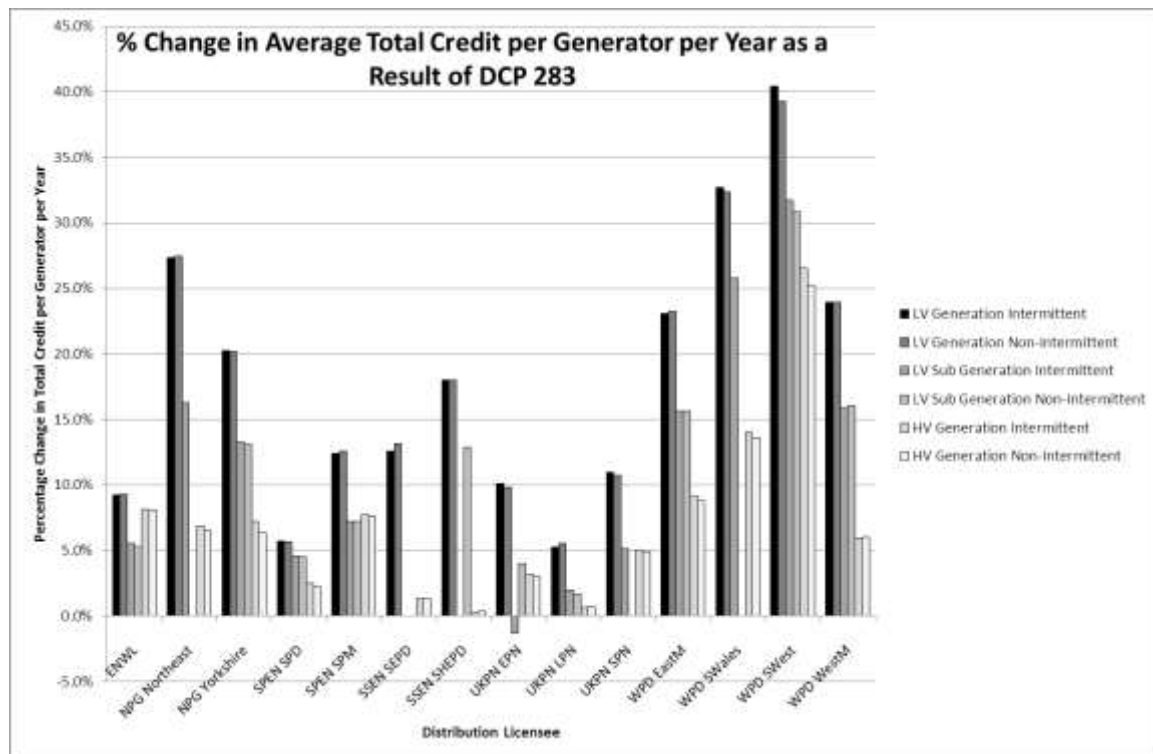
6.14 The increase in credits for embedded generators is more substantial, with LV connected embedded generators seeing up to 40% increases in credits. Note, the anomalous reduction in credits for LV Sub connected embedded generators is only seen in one licensee, and is as a result of the increase in the reactive power charge (as a result of removing customer contributions) more than offsetting the increase in the active power credits. The spread of impacts on credits for embedded generators across DNO licensees is driven by the varying level of customer contributions rather than levels of embedded generation connected. For example, the UKPN licensees generally have lower levels of customer contributions, and hence the increase in credits is smaller than in other licensees. Note that the percentage changes here are to the level of credit, i.e. a positive percentage movement implies a higher overall credit being awarded.



% Change in Average Total Credit per Generator	GB Min	GB Average	GB Max
LV Generation Intermittent	5.24%	17.99%	40.41%
LV Generation Non-Intermittent	5.57%	17.94%	39.30%
LV Sub Generation Intermittent	( 1.30%)	10.12%	31.74%
LV Sub Generation Non-Intermittent	0.00%	7.94%	30.88%
HV Generation Intermittent	0.23%	7.03%	26.55%
HV Generation Non-Intermittent	0.33%	6.76%	25.18%

**Table 2 - Impact on embedded generators of removing customer contribution from the calculation of credits for embedded generators**

6.15 Figure 2 shows the spread of impact on embedded generators across DNO licensees.



**Figure 2 - Spread of impacts of DCP 283 on embedded generators across DNO licensees**

## Environmental Impacts

6.16 In accordance with DCUSA Clause 11.14.6, the Working Group assessed whether there would be a material impact on greenhouse gas emissions if DCP 283 were implemented. The Working Group did not identify any material impact on greenhouse gas emissions from the implementation of this CP.

## Engagement with the Authority

6.17 Ofgem has been fully engaged throughout the development of DCP 283 as an observer on the Working Group.

## 7 Implementation

- 7.1 The Working Group sought views from Parties, via a question set out in the second consultation, as to which of two proposed implementation dates (01 April 2019 or 01 April 2020) was preferred. The Working Group noted that the majority of responses were in favour of a 01 April 2020 implementation date. The Working Group agreed that the implementation of DCP 283 should be pushed back to 01 April 2020.

## 8 Legal Text

- 8.1 The Working Group note that there is an overlap of changes to the same paragraphs of legal text as proposed by the DCP 243 Working Group. The Working Group have highlighted the broader interaction between DCP 283 and DCP 243 in, paragraphs 5.39 to 5.41 above.
- 8.2 The legal text provided in Attachment 1 encapsulates the legal text changes for DCP 283 and indicates the outcome to this paragraph should DCP243 also be approved
- 8.3 For DCP 283, Schedule 16, paragraph 31 is amended as follows:

The network model is discounted by customer contributions at each network level in the calculation of demand tariffs only. For the purposes of deriving generation credits, the network model is not discounted by any customer contributions. ~~In the case of generators, the proportions relate to the notional assets whose construction or expansion might be avoided due to the generator's offsetting of demand on the network, and takes the same values as for a demand user at the same network level of supply~~

- 8.4 The Working Group would also highlight that the updating of the model version number reflects the changes made by DCP 293<sup>3</sup> which has recently been approved by the Authority. DCP 293 introduces new text at the beginning of the Schedules 16,17,18, 20 and [XX]<sup>4</sup> and also amends the Clauses in each that stipulates which version of any given model DNOs are to use and the date which the DCUSA Panel approved that version of the model. DCP 293 is to be implemented on 01 April 2018 in advance of this change.

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<sup>3</sup> DCP293 – “charging methodology cut-off date”

<sup>4</sup> Schedule [XX] will be introduced by DCP 234 – ‘Merging the PCDM and Extended PCDM’ which has been approved for implementation on 01 April 2018

## 9 Code Specific Matters

### Modelling Specification Documents

9.1 See applicable paragraphs in Impact section above and in Attachment 6.

### Reference Documents

9.2 Not applicable.

## 10 Recommendations

### Panel's Recommendation

10.1 The Panel approved this Change Report on 20 December 2017. The Panel consider that the Working Group have carried out the level of analysis required to enable Parties to understand the impact of the proposed amendment and to vote on DCP 283.

10.2 The Panel have recommended that this report is issued for Voting and DCUSA Parties should consider whether they wish to submit views regarding this CP.

## 11 Attachments

### Attachments

- Attachment 1 – DCP 283 Legal Text
- Attachment 2 – DCP 283 Voting Form
- Attachment 3 – DCP 283 Change Proposal
- Attachment 4 – DCP 283 Consultation and Collated Responses
- Attachment 5 – DCP 283 Second Consultation and Collated Responses
- Attachment 6 – Modelling Documentation
- Attachment 7 – Impact Assessment
- Attachment 8 – RFI and Responses