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| **DCUSA Consultation** | | At what stage is this document in the process? |
| **DCP 287** **Generation Credits in the EDCM**  **Raised on 7 December 2016 as a Standard Change** | | |  | | --- | | **01 – Change Proposal** | | **02 – Consultation** | | **03 – Change Report** | | **04 – Change Declaration** | |
| **Purpose of Change Proposal:**  DCP 287 seeks to amend the calculation of credits for embedded generation in the EDCM to take account of potential cost savings for DNOs that can be attributed to embedded generation in the areas of transmission exit charges, direct costs, indirect costs and network rates. | | |
|  | The Workgroup recommends that this Change Proposal should proceed to Consultation  Parties are invited to consider the questions set in section 10 and submit comments using the form attached as Attachment 1 to [dcusa@electralink.co.uk](mailto:dcusa@electralink.co.uk) by **xx xxxx 2018.**  The Working Group will consider the consultation responses and determine the appropriate next steps for the progression of the Change Proposal (CP). | |
| Description: Description: High_Impact | Impacted Parties: Distribution Network Operators (DNOs), Distributed Generators and Suppliers | |
| Description: Description: High_Impact | Impacted Clauses:  Schedule 17 - EHV Charging Methodology (FCP Model); and  Schedule 18 - EHV Charging Methodology (LRIC model | |

***Guidance On The Use Of This Template****:*

*Code Administrators will produce this Report using the original proposal as the source.*

*The Workgroup will verify all of the information provided, adding the Impact Assessment.*

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| Contents  1 Summary 3  2 Governance 4  3 Why Change? 4  4 Code Specific Matters 6  5 Working Group Assessment 6  6 Solution and Legal Text 14  7 Relevant Objectives 15  8 Impacts & Other Considerations 16  9 Implementation 16  10 Consultation Questions 18  11 Attachments 19  Timetable  The timetable for the progression of the CP is as follows:   |  |  | | --- | --- | | Change Proposal timetable: | | | Activity | Date | | Initial Assessment Report Approved by Panel | 21 December 2016 | | First Consultation issued to Parties | 06 October 2017 | | First Consultation closes | 27 October 2017 | | Second Consultation issued to Parties |  | | Second Consultation closes |  | | Change Report issued to Panel |  | | Change Report issued for Voting |  | | Party Voting Ends |  | | Change Declaration Issued to Authority |  | | Authority Decision |  | | Implementation | 01 April 2021 | | **Any questions?** |
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1. Summary

#### What?

* 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.
  2. This CP (Attachment 2) addresses the issue of whether the calculation of credits for embedded generators in the Extra High Voltage (EHV) Distribution Charging Methodology (EDCM) should include credits for the avoidance of costs on behalf of the Distribution Network Operator (DNO) relating to transmission exit charges, direct costs, indirect costs and network rates.

#### Why?

* 1. The level of credits for embedded generators within the EDCM is determined from the Charge 1 that results from a powerflow analysis of the DNO’s network. Although this captures future reinforcement costs, it does not necessarily reflect the full costs savings that can be attributed to embedded generators. More cost reflective credits for generators will place incentives on embedded generators that reflect the benefits they bring to DNOs.

#### How?

* 1. The proposed solution is to apply credits to eligible[[1]](#footnote-1) EDCM embedded generators in the areas of:
* Transmission exit charges;
* Direct costs;
* Indirect costs; and
* Network rates.

1. Governance

#### Justification for Part 1 Matter

* 1. DCP 287 is considered a Part 1 Matter as it directly affects the level of charges for embedded generators and therefore impacts on competition for embedded generation as specified under clause 9.4.2 (A) of DCUSA, and will indirectly affect (through scaling) the level of charges for demand customers. Therefore, DCP 287 will go to the Authority for determination after the voting process has been completed.

#### Requested Next Steps

* 1. Following a review of the Consultation responses, the Working Group will progress to Change Report phase.

1. Why Change?

#### Background of DCP 287

* 1. The principle of this proposal is to amend the credits awarded to EDCM embedded generators to reflect all of the components that result in cost savings to the DNO in a similar way to the methodology used in the Common Distribution Charging Methodology (CDCM), which is used to determine charges for designated High Voltage (HV) and Low Voltage (LV) properties. Each component is listed separately below.

##### ****Transmission Exit Charges****

* 1. The review of embedded benefits undertaken by National Grid in 2013 (charging methodology paper GB ECM-23 Transmission Arrangements for Embedded Generation) determined a value for the avoided cost of embedded generation on the transmission network. This analysis excluded the cost of transformation located at Grid Supply Points (GSPs), known as supergrid transformers (SGTs). This is because SGTs tend to be fully contributed (i.e. paid for by the DNO) and the cost recovered from the DNO via transmission exit charges.
  2. Under the EDCM, a credit for offsetting transmission exit costs is only paid to qualifying embedded generators that have an agreement with the DNO, the terms of which require the embedded generator, for the purposes of P2/6 compliance, to export power during SGT outage conditions. As most EDCM embedded generators do not have this agreement, very few receive a credit in this respect.
  3. Transmission exit charges recover the capital cost of GSPs, on behalf of transmission companies, from DNOs. Embedded generators may offset demand at the GSP and therefore reduce the need for future reinforcement at the GSP. Embedded generators may also increase the amount of spare capacity at the GSP which enables more demand to connect without triggering reinforcement. This principle is accepted within the CDCM, where embedded generators receive a credit for offsetting transmission exit charges, but not within the EDCM. In addition, the costs of future reinforcement of GSPs is not included in the locational element of the charge (Charge 1) due to the ownership lying with the transmission company.

##### ****Direct Costs****

* 1. Within the CDCM, designated HV and LV embedded generators receive a credit for reducing direct operating costs at voltage levels above the level of connection. This is because they reduce the demand and therefore the level of infrastructure required at higher voltage levels. This results in less reinforcement and a saving in direct costs.
  2. Annex 1 of schedule 17, s8.3 (d) and schedule 18, s7.4 (d) set out the costs to be included when deriving the future reinforcement costs under the Forward Cost Pricing (FCP) and the Long Run Incremental Cost (LRIC) approaches to load flow modelling respectively, and are as follows:

(d) The typical unit costs used to derive the cost of reinforcement for a Branch shall:

(i) reflect the modern equivalent asset value of reinforcing the particular asset;

(ii) include overheads directly related to the construction activity;

(iii) include building and civil engineering works, in unmade ground.

* 1. The costs outlined above therefore do not reflect the savings that result from lower direct costs that are realised by the DNO due to the reduction in size of the infrastructure that needs to be maintained by the DNO. This CP suggests awarding an additional credit to EDCM embedded generators for the avoided direct costs associated with increased infrastructure that may have been required if the embedded generators were not connected to the DNO network.
  2. Within the EDCM an operating intensity of 68% is applied to direct costs for the derivation of demand charges. This operating intensity is used to reflect the apportionment of direct and indirect costs between EDCM and CDCM customers. Effectively, this parameter states that more direct costs (on a relative basis) are spent on the LV and HV network than the EHV network. This CP does not intend to amend this operating intensity which is presented for information only.

##### ****Indirect Costs****

* 1. The CDCM assumes the degree to which indirect costs contribute to demand costs or generation credits on a forward-looking basis via a 60% multiplier within the methodology i.e. 60% is used to represent the proportion of indirect costs which are assumed to vary with demand. There is no equivalent factor applied within the EDCM; demand charges as indirect costs are recovered on a capacity basis rather than a unit basis.

##### ****Network Rates****

* 1. The proposer believes that network rates are another avoidable cost for DNOs. Where fewer assets are required by the DNO the amount of network rates expenditure by the DNO is reduced. As this expenditure is not considered during the derivation of Charge 1 it is therefore not built into the credit assigned to EDCM embedded generators. The proposer therefore believes that the calculation of credits for EDCM embedded generators should be amended to incorporate any savings due to avoided network rates.

1. Code Specific Matters

#### Reference Documents

* 1. The Working Group agreed that there are no other Working Groups that impact upon the development of DCP 287 however it noted the work being undertaken by DCP 313 [‘Eligibility Criteria for EDCM Generation Credits](https://www.dcusa.co.uk/Lists/Change%20Proposal%20Register/DispForm.aspx?ID=341&Source=https%3A%2F%2Fwww%2Edcusa%2Eco%2Euk%2FSitePages%2FActivities%2FChange%2DProposal%2DRegister%2Easpx&ContentTypeId=0x0100684A1DE09E1F9740A444434CF581D435)’ which is looking into clarifying the eligibility criteria for EDCM embedded generators to receive Charge 1 credits. This change proposal replaces DCP 291 [‘Application of Generation Credits to EDCM Customers’](https://www.dcusa.co.uk/Lists/Change%20Proposal%20Register/DispForm.aspx?ID=320&ContentTypeId=0x0100684A1DE09E1F9740A444434CF581D435&Source=https%3A%2F%2Fwww%2Edcusa%2Eco%2Euk%2FSitePages%2FActivities%2FChange%2DProposal%2DRegister%5FUSL2%2Easpx%23InplviewHasheedde852%2D0231%2D4b85%2D87ff%2D0f14d79826f5%3DPaged%253DTRUE%2Dp%5FDCP%253D288%2Dp%5FID%253D314%2DPageFirstRow%253D21) which was previously looking at the same area and was withdrawn.
  2. The Working Group agreed that there is no conflict between DCP 313 and this change proposal. DCP 313 will determine who receives EDCM Generation Credits, whereas this CP will determine how those credits are to be derived.

1. Working Group Assessment

#### DCP 287 Working Group Assessment

* 1. The DCUSA Panel established a Working Group to assess DCP 287. This Working Group consists of DNO, Supplier, consultancy, trade body 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).

##### First Consultation

* 1. To aid the further development of the solution for DCP 283, the Working Group issued a consultation to Parties in October 2017. The responses and subsequent review of responses by the Working Group is detailed within Attachment 3 and an overview of the conclusions drawn from the review are outlined below.
  2. The Working Group agreed that further development work is required to:
* justify each of the four elements including what the status quo is and why this change is better or worse in respect to each element;
* determine whether there is a direct relationship between energy flows and indirect costs, direct costs and network rates incurred by a DNO, or whether the nature of the relationship is more complex;
* determine whether there are any conditions that must be applied in regard to the application of generation credits, including justification as to why the discrepancy between EDCM and CDCM is appropriate; and
* develop a table covering the costs to the DNO associated with direct costs, indirect costs and network rates in order to understand what may be impacted should generation not be connected.
  1. In order to determine the outcome of the above, the approach taken on transmission exit charges, direct costs, indirect costs and network rates is detailed below.

##### Transmission Exit Charges

* 1. The Working Group developed a request for information for DNOs and a pilot exercise on the peak demand associated with one DNO area.

##### Request for Information (RFI)

* 1. The RFI requested the following:
* How many generators do you have in each licence area to whom a capacity-based credit related to transmission exit charges is applied as per section 10 of schedule 17 and 18?;
* Do you envisage an increase in the number of Generators who are eligible for a capacity-based credit related to transmission exit charges as per section 10 of schedule 17 and 18 in the short, medium and long term?; and
* Based on your week 24 submission, what proportion of GSPs in your area peaked in the super-red period in 2016/17?

##### RFI Conclusions

* 1. The responses from DNOs indicated that there are:
* no generators receiving a credit related to transmission exit charges at the present time;
* none likely to be receiving credit in the short, medium or long term; and
* seven DNO licensed regions that do not peak in the super red time period. The range being between 58% and 88% of GSPs that do within such licensed regions.
  1. Reviewing these responses, the Working Group made the following observations:
* One Working Group member noted that the responses to Question 1 and Question 2 indicate that DNOs don’t require bilateral contracts with generators and it does not support the case that generators help reduce transmission exit charges – if they did then DNOs would contract with them for that purpose;
* Some Working Group members noted that the lack of such contracts does not necessarily mean that generators are not offsetting any transmission exit charges costs as the terms of any such contracts are quite specific in the requirement to export under SGT outage conditions. The Working Group agreed that further analysis was required to determine whether a generator, in its normal operation (i.e. without a specific contract) is potentially offsetting transmission exit charges costs; and
* It was suggested that peak demand may simply be pushed into a different time if generation was removed from transmission exit charges. This suggestion was tested against a pilot scheme undertaken by Northern Powergrid to understand the impact generation is having on peak demand (see para 5.13 below);
  1. Under the EDCM, a credit for offsetting transmission exit costs is only paid to qualifying embedded generators that have an agreement with the DNO, the terms of which require the embedded generator, for the purposes of P2/6 compliance, to export power during SGT outage conditions. It was suggested that if credits are to be provided in addition to this then perhaps the approach should be to include such a provision within the bi-lateral agreement. The counter argument is that this would introduce a significant administrative burden and may also result in differing contract terms across the country. It was suggested that a common approach to amend the EDCM is preferable via this CP.
  2. The Working Group would like industry views on whether a bi-lateral contractual approach is supported in preference to an amendment to the EDCM or whether there is another approach that should be considered for credits to transmission exit charges.

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| Question 1: Do you favour the bi-lateral contractual approach or an amendment to the EDCM or is there a more effective way for embedded generators to become eligible for transmission exit charge credits? Please provide rationale. |

* 1. The Working Group discussed the application of transmission exit charge credits to EDCM embedded generators and how these could be applied. The Working Group initially discussed the analysis provided by Northern Powergrid, which shows the peak demand at Northern Powergrid’s GSPs, and the hypothetical peak demands which would have been observed if EDCM embedded generators had not been connected.
  2. It was noted from this analysis that the impact varies significantly from GSP to GSP, with some seeing no difference and some seeing a significant drop in the peak demand which is expected to have been observed had EDCM embedded generators not been connected. The former scenario implies that there would be no cost saving in transmission exit charges for the DNO as a result of EDCM embedded generators as the peak demand for which the GSP is designed would be the same regardless of EDCM embedded generators; conversely the latter implies that there may have been a cost saving in transmission exit charges for the DNO as a result of EDCM embedded generators as the peak demand for which the GSP is designed would have been higher had the EDCM embedded generators not been connected.
  3. The Working Group discussed whether it would be possible to calculate a GSP specific credit to be applied to EDCM embedded generators connected at each GSP, reflecting the contribution of EDCM embedded generators at that GSP to offsetting GSP peak demand. It was agreed that, in order to be cost reflective, such a credit would need to take account of any headroom at the GSP – if EDCM embedded generators are offsetting peak demands at GSPs with significant headroom then the value will be minimal; conversely if EDCM embedded generators are offsetting peak demands at GSPs which would otherwise be overloaded then the value would be significant.
  4. The Working Group then considered the way in which transmission exit charges are allocated to demand users, in order to inform its thinking on options for the application of credits to generators. It was noted that, for demand customers, a ‘Transmission Exit Charging Rate’ is calculated in the EDCM, which is based on the total transmission exit charges forecast for the year, divided by an estimate of peak demand (across both CDCM and EDCM customers). Each EDCM demand customer’s contribution to transmission exit charges is then determined from that customer’s contribution to peak demand, as determined by usage in the super-red timeband.
  5. One Working Group member suggested that it would be inappropriate to introduce a new GSP specific method of allocating transmission exit charge credits without also considering a GSP specific method of allocating transmission exit charges for demand. Any such change to demand charges would be outside the scope of this change, so the Working Group member suggested that the best solution for this change would be use the same ‘Transmission Exit Charging Rate’ for generation as is used for demand, but with a credit determined for each EDCM embedded generator which is eligible for charge one credits based on the output of that EDCM embedded generator in the super-red period.
  6. The Working Group agreed that this is the solution that should be progressed for transmission exit charges. By limiting this to eligible generators it preserved the separation from DCP313 on the eligibility criteria which is being progressed under that CP and also ensured that where there are generator dominated areas the benefit that they would receive from such a credit is likely to be zero or close to zero.

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| Question 2: Do you agree with the Working Group approach for progression of Transmission Exit Charges? Please provide rationale. |

##### Direct costs

* 1. The Working Group reviewed the table below which identifies various categories of Direct Costs i.e. the cost of those activities which involve or related to physical contact with system assets.

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| **Direct Costs** |
| Staff whose work involves physical contact with system assets. This can include the element of labour costs associated with trench excavation staff, craftsmen, technicians, technical engineers, administration and support staff, network planners and designers where a portion of their time involves physical contact with system assets, however only that portion spent on direct activities may be included. It will include idle, sick, non-operational training and other downtime of staff, which cost should follow their normal time allocations. |
| Operational Engineers working on commissioning of assets, physically changing protection settings, issuing safety documentation or liaising with the control centre are considered direct activities |
| Contractors - the total charges invoiced by external contractors for the primary purpose of performing direct activities. |
| Materials from stores or purchased and delivered directly to site for use in performing direct activities. In addition, this includes the cost of the materials (stores issues) for refurbishing system assets. |
| Servitude and easement to enable the direct activity to be performed. This does not include the cost of management or administration of these. |
| Related Party Margins - charged by a Related Party for work performed on direct activities. In addition, includes, for the purposes of flooding, site surveys and non site based costs. |
| Low carbon networks - resourcing and project preparation and Second Tier bid preparation |

* 1. The Working Group discussed how direct costs may be reduced through the presence of embedded generation. The potential areas where direct costs may be reduced are as follows:
* Reduced energy flows through existing assets – embedded generation will typically reduce the amount of energy flowing upstream of the asset by offsetting demand flows. The Working Group noted that this may not be the case where a network is generation dominated. The Working Group did not identify material direct cost savings from reduced powerflows in existing assets; and
* Reduced direct costs associated with avoided reinforcement – embedded generation can offset the need for reinforcement of existing assets or enable existing assets to be replaced with smaller, lower cost assets. Where this occurs, the direct costs associated with these new assets will be saved by the DNO.
  1. The Working Group noted that DNOs may experience reduced level of direct costs under bullet point two above. The EDCM is a forward looking charging methodology and the powerflow approach to determine charge 1 is based on future reinforcement costs. However, this relates to the capital cost saved and does not include the direct costs that would have been incurred if the reinforcement physically took place.
  2. The Working Group recognised that any saving in direct costs relating to future reinforcement would be greater where there is a greater likelihood of this reinforcement occurring. The charge 1 element from the powerflow analysis represents this likelihood as it is high when assets are close to reinforcement and low when they are not. Consequently, the proposed solution to apply the direct charging rate to generation credits would intuitively increase credits more where assets are close to reinforcement and have a small impact where there is lots of spare capacity and potentially zero in generator dominated areas.

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| Question 3: Do you agree with the proposed application to adopt a Charge 1 element to credits associated with Direct Costs? Please provide rationale. |

##### Indirect Costs

* 1. Activities listed below, which in most cases support work being physically carried out on network assets, that could not, on their own, be classed as a direct network activity. Indirect Activities generally do not involve physical contact with system assets, whereas direct activities do.

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| **Indirect Costs** |
| Closely Associated Indirects |
| Business support costs |
| Non-Operational Capex |
| Operational Engineers working on planning and project mobilisation, preparing and planning associated with protection settings, administration of outages, contract specification and liaising with contractors and customers are considered Indirect Activities |

* 1. Although there was a majority support in the first consultation for the use of the 60% value (as used in the CDCM) to determine the proportion of indirect costs which EDCM embedded generators have the potential to offset, the Working Group reserved judgement until further analysis on the costs was considered.
  2. This analysis was undertaken on all DNOs ‘closely associated’ indirect costs as a percentage of ‘total’ indirect costs (Attachment 4) since this was believed to be closely linked to any deferred costs that generators may contribute to this part of the DNO indirect costs.
  3. The average was 59.6% across the DNOs, with a minimum of 53.4% and a maximum of 63.3%. The average closely aligns with that of the 60% value used within the CDCM although the method adopted is different and perhaps such a value therefore may also be appropriate for use in the EDCM.
  4. As with Direct Costs, the Working Group recognised that any savings relating to future reinforcement would be greater where there is a greater likelihood of this reinforcement occurring. Consequently, the proposed solution to apply the indirect charging rate to generation credits would intuitively increase credits more where assets are close to reinforcement and have a small impact where there is lots of spare capacity and potentially zero in generator dominated areas.

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| Question 4: Do you agree with the proposed application to adopt a Charge 1 element to credits associated with Indirect Costs? Please provide rationale. |

##### Network Rates

* 1. A significant number of respondees to the first consultation supported Option 1 – amending the calculation for Charge 1 in preference to Option 2 – NUF. The Working Group agreed to progress Option 1 which ensures an element of protection in terms of applying generation credits to exporting GSPs, whereas the NUF approach does not.
  2. For Network Rates, the information gathered is from the Government Valuation Office website, for which a link is below. Exactly what is included within the calculation of the Network Rates is listed in section 5 ‘Electricity Distribution Hereditaments’. This site, however is out of date, and still refers to DCPR5 and not ED1, however the arrangements for Network Rates has not changed in recent times.

<https://www.gov.uk/guidance/rating-manual-section-6-part-3-valuation-of-all-property-classes/section-371-electricity-distribution-networks>

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| **Network Rates** |
| Type |
| Buildings and structures at sub stations and depots, |
| Underground cables and ducts |
| Overhead lines, towers and poles (which are rateable plant and machinery) |
| The “land” within which the wires sit |
| The meters |

* 1. The methodology used to determine the networks rates bill is the receipts and expenditure method. This method determines a DNO’s network rates bill based on the underlying profitability of the network business to the tenants (deemed to be the shareholders). The underlying methodology is to determine the income (receipts) which are well known ahead of time based on the regulatory price control. The operating cost elements are forecast based on historical costs, Ofgem’s forecast of operating costs and the DNO business plans. Depreciation is also taken into account which is set at 20% of operating costs.
  2. The Working Group discussed whether a DNO’s network rates bill will change if the assets in situ change. Some Working Group members were concerned that the receipts and expenditure method would mean that where a DNO used an existing asset more efficiently by contracting with an embedded generator, then the profitability of the business would increase and therefore the network rates bill would increase rather than decrease.
  3. Another Working Group member put forward the view that the underlying driver of the profit for a networks company is based on the assets in situ as the network company is able to earn a rate of return for all the assets they own. Consequently, an embedded generator that reduces the number of assets the DNO owns will reduce the profitability of the network company and thereby reduce their network rates bill.
  4. The Working Group member has provided a simple example to illustrate this point. In this example a DNO has a primary substation which needs reinforcement by installation of an additional transformer at an additional cost of £1m. An embedded generator connects and avoids the need for this additional asset by providing the required network security to meet the network planning requirements (P2/6). Assuming the DNO earns a rate of return of 5% on the MEAV of the asset value, the profitability of the DNO based purely on the assets in place is as follows:

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| **Scenario** | **With generation** | **Without Generation** |
| Assets in place | Primary Substation | Primary Substation + additional transformer |
| Cost | £3,000,000 | £4,000,000 |
| Rate of return (p.a.) | 5% | 5% |
| Profit | £150,000 | £200,000 |

* 1. The table above shows that when the generator is not present, the DNO makes a higher profit based on the additional assets. This means that under the receipts and expenditure method, the network rates bill for the DNO will be higher where the generator is not present.
  2. The example above is simplistic and some Working Group members highlighted that there are additional complexities to how revenues and costs are determined such as dird factors for TOTEX expenditure and other incentive schemes. The Working Group member who provided the example, highlighted that regardless of these additional factors the underlying driver of the profitability of a network company is the assets in place.
  3. The Working Group recognised that any savings relating to network rates would be greater where there is a greater likelihood of this reinforcement occurring. Consequently, the proposed solution to apply the indirect charging rate to generation credits would intuitively increase credits more where assets are close to reinforcement and have a small impact where there is lots of spare capacity and potentially zero in generator dominated areas.
  4. This approach is also supported by a significant number of respondents to the first consultation who supported Option 1 – amending the calculation for Charge 1 in preference to Option 2 – NUF. The Working Group agreed to progress Option 1 which ensures an element of protection in terms of applying generation credits to exporting GSPs, whereas the NUF approach does not

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| Question 5: Do you agree with the proposed application to adopt a Charge 1 element to credits associated with Network Rates? Please provide rationale. |

##### Price Control

* 1. The Working Group is seeking views as to the impact on the DNO Price Control that such credits would have and whether eligible embedded generators provide a genuine reduction of costs which would result in a reduction in demand revenue.

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| Question 6: What impact will this change have on the DNO price control? Please provide your rationale. |

1. Solution and Legal Text
   1. A new sub section in both Schedule 17 and 18 is created entitled “6b – Generation Credits”.
   2. A new paragraph is introduced that contains the formula for the super red export rate (Charge 1). This being the sum of the credit covering:

* the current credit on transmission exit charges,
* the credit being driven from direct costs, indirect costs and network rates and
* the new credit being applied to transmission exit charges.
  1. Separate paragraphs are created for the three elements that make up the Charge 1 credit and these also contain a formula to calculate that element of the credit.
  2. In all instances the credit is only available for eligible embedded generators.
  3. The legal text can be found as Attachment X.

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| Question 7: Do you have any comments on the legal text? |

1. Relevant Objectives

## **Assessment Against the DCUSA Objectives**

* 1. The Proposer considers that the following DCUSA Objectives are better facilitated by DCP 287.

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| Impact of the Change Proposal on the Relevant Objectives: | |
| **Relevant Objective** | Identified Impact |
| Charging Objective One - 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 | Neutral |
| 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) | Positive |
| 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. | Positive |
| Charging Objective Four - 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 | Neutral |
| Charging Objective Five - that compliance by each DNO Party with the Charging Methodologies facilitates compliance with the Regulation on Cross-Border Exchange in Electricity and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators | Neutral |
| Charging Objective Six - that compliance with the Charging Methodologies promotes efficiency in its own implementation and administration. | Neutral |

* 1. The proposer believes that this CP better meets charging objective two as the tariffs for EDCM embedded generators will be more cost reflective and therefore 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.
  2. The proposer believes that this CP better meets charging objective three as it increases the cost reflectivity of tariffs within the EDCM by awarding credits to eligible 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.

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| Question 8: Do you believe that this change proposal better facilitates the DCUSA Charging Objectives? Please provide your rationale against each objective |

1. Impacts & Other Considerations

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

* 1. Ofgem launched a SCR on the 4th August 2017 on the Targeted Charging Review. One aspect of this is looking into residual charges via a Significant Code Review, which the Working Group believes does not impact this CP. It is therefore suggested that unless directed otherwise by the Authority that this CP should continue to be developed.
  2. The Working Group is also aware of a further initiative called the Active Network Scheme however this is currently subject to further development work.

#### Consumer Impacts

* 1. . <put here the impact assessment based on the new legal text and model>.

#### Environmental Impacts

* 1. 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 287 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

* 1. Ofgem has been fully engaged throughout the development of DCP 287 as an Observing member of the Working Group.

1. Implementation
   1. Since this change will affect tariffs the proposed implementation date for DCP 287 is 01 April 2020.

|  |
| --- |
| Question 9: Do you agree with the proposed implementation date? Please provide your rationale. |

* 1. The Working Group are of the view that there are no costs associated with implementing this change by Parties.

|  |
| --- |
| Question 10: Do you agree that there are no costs associated with the implementation of this change. If not please provide an estimate of the costs and what they cover. |

1. Consultation Questions
   1. The Working Group is seeking industry views on the following consultation questions:

|  |  |
| --- | --- |
| No. | Questions |
|  | Do you favour the bi-lateral contractual approach or an amendment to the EDCM or is there a more effective way for embedded generators to become eligible for transmission exit charge credits? Please provide rationale. |
|  | Do you agree with the Working Group approach for progression of Transmission Exit Charges? Please provide rationale. |
|  | Do you agree with the proposed application to adopt a Charge 1 element to credits associated with Direct Costs? Please provide rationale. |
|  | Do you agree with the proposed application to adopt a Charge 1 element to credits associated with Indirect Costs? Please provide rationale. |
|  | Do you agree with the proposed application to adopt a Charge 1 element to credits associated with Network Rates? Please provide rationale. |
|  | What impact will this change have on the DNO price control? Please provide your rationale |
|  | Do you have any comments on the legal text? |
|  | Do you believe that this change proposal better facilitates the DCUSA Charging Objectives? Please provide your rationale against each objective |
|  | Do you agree with the proposed implementation date? Please provide your rationale. |
|  | Do you agree that there are no costs associated with the implementation of this change? If not please provide an estimate of the costs and what they cover. |

## Responses should be submitted using Attachment 1 to dcusa@electralink.co.uk no later than, **xx xxxx 2018**.

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

1. Attachments

#### The following documents are attached

* Attachment 1 – DCP 287 Consultation Response Form
* Attachment 2 – DCP 287 Change Proposal
* Attachment 3 – First consultation – consolidated responses with Working Group comments
* Attachment 4 – Indirect cost analysis
* Attachment 5 – DCP 287 Proposed Legal Text
* Attachment 6 – Impact Assessment

1. Eligible generators are those which have ‘proportion eligible for Charge 1 credits’ set to 1. The proportion eligible for Charge 1 credits is zero if the F factor that is assigned to the generator is zero and 1 otherwise. [↑](#footnote-ref-1)