DCUSA Change Declaration

At what stage is this document in the process?

01 – Change Proposal

02 – Consultation

03 – Change Report

04 – Change Declaration

DCP 268

DUoS Charging Using HH Settlement Data

Raised on 14 March 2016 as a Standard Change

Purpose of Change Proposal:

DCP 268 seeks to facilitate a transition to half-hourly (HH) settlement for non-half hourly (NHH) customers by moving to a time band charging basis, based on the HH (profiled) data used in settlement.

DCUSA Parties have voted on DCUSA Change Proposal (DCP) 268 with the outcome being a recommendation to the Authority on whether the Change Proposal (CP) should be accepted or rejected.

The DCUSA Parties consolidated votes are provided as Attachment 1.

For DCP 268, DCUSA Parties have voted and recommended to the Authority to determine that:

- **the proposed variation (solution) should be accepted; and**
- **the implementation date should be accepted**

Impacted Parties: Distribution Network Operators (DNOs), Independent Distribution Network Operators (IDNOs) and Suppliers.

	Impacted Clauses: Schedule 16 'Common Distribution Charging Methodology' Schedule 17 'EHV Charging Methodology (FCP Model)' Schedule 18 'EHV Charging Methodology (LRIC Model)' Schedule 19 'Portfolio Billing' Schedule 20 'Production of the Annual Review Pack' and Schedule 21 'Portfolio Billing for Nested Networks'

Contents

Any questions?

Contact:

Code Administrator

DCUSA@electralink.co.uk

0207 432 3011

Proposer:

Lee Wells – Northern Powergrid

Lee.Wells@northernpowergrid.com

07885712226

DCUSA

Timeline

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

Change Proposal timetable

Activity	Date
Initial Assessment Report Approved by Panel	16 March 2016
Consultation One issued to Parties	18 May 2016
Request for Information Issued to Parties	31 August 2016
Consultation Two issued to Parties	17 February 2017
Change Report issued to Panel	14 June 2017
Change Report issues for Voting	23 June 2017
Change Declaration issues to Parties & Authority	18 July 2017
Authority decision to send back Change Proposal	20 October 2017
Consultation Three issued to Parties	21 February 2018
Change Report issued to the Panel	11 April 2018
Change Report issued for Voting	20 April 2018
Change Report voting deadline	14 May 2018
Change Declaration issued to Parties & Authority	16 May 2018
Authority Decision	21 June 2018
Implementation Date	01 April 2020

1 Summary

What?

1.1 The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract principally between electricity Distributors and 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 The Competition and Markets Authority (CMA) in their *'Notice of provisional findings*[1]' of its Energy Market Investigation advised that the absence of a firm plan to move to half hourly (HH) settlement for domestic and microbusinesses electricity customer is a feature of the Small Medium Enterprise (SME) retail electricity market in Great Britain which gives rise to an Adverse Effect on Competition (AEC).

1.3 Ofgem issued a consultation[2] on *'Half-Hourly (HH) Settlement – The Way Forward'* which set out their intention to reform the electricity settlement arrangements to include facilitating Suppliers settling their domestic and smaller non-domestic electricity customers on a HH basis. HH settlement is initially proposed to be on an elective basis with a future expectation that all Suppliers will be mandated to settle their customers on a HH basis.

1.4 Both the CMA and Ofgem have produced further documentation on this topic, namely the CMA's Energy Market Investigation Final Report[3] and Ofgem's Elective Half Hourly Settlement: Conclusions Paper[4].

1.5 DCP 268 seeks to support these initiatives by facilitating a transition to HH settlement for NHH customers by moving to a Distribution time band charging basis, based on the HH (profiled) data used in settlement.

1.6 This change will have the additional benefits identified by the Distribution charging Methodology Forum (DCMF) Methodology Issues Group (MIG) of:

- Simplifying the Common Distribution Charging Methodology (CDCM) by not accommodating the historic NHH charge structures;
- Moving to Use of System (UoS) charging based on HH settlement will simplify the billing framework and remove barriers for customers moving between NHH & HH settlement;
- Enables innovative NHH retail tariff structures; and
- Removes risk and complexity for all industry participants.

---

[1] https://assets.publishing.service.gov.uk/media/559aacbee5274a1559000017/EMI_Notice_of_PFs.pdf

[2] https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-settlement

[3] https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf

[4] https://www.ofgem.gov.uk/system/files/docs/2016/05/elective_hhs_conclusions_paper.pdf

How?

1.7 This CP is seeking to transition all existing NHH customer on to the Red Amber Green (RAG) or Black, Yellow and Green (BYG) tariff structures, with UoS charging based on HH (profiled) data used in settlement.

1.8 In achieving this, some of the existing tariffs have been merged together (33 tariffs down to 16) with the data from each group of customers on such tariffs within the CDCM model. Tariff mapping tables (Attachment 8) for both the CDCM and the EDCM have been produced to highlight this in more detail.

1.9 Some of the existing tariffs (LV Medium Non-Domestic, LVS Medium Non Domestic and HV Medium Non Domestic), that over time would become redundant due to the move to HH tariffs introduced for PC 5-8 customers, have been merged with the Non Domestic Aggregated tariff to mitigate any remnants of such a transfer process still remaining.

1.10 The distinction between the intermittent and non-intermittent generation is removed. The distinction is no longer required as the DUoS charges will be on a RAG basis regardless of whether the generation is intermittent or non-intermittent. This provides a simplification to the generation tariffs and removes the existing unnecessary complication of allocating different generation across the two tariffs.

1.11 Similarly, unmetered tariffs have been reduced to one from five based on BYG tariff structures.

1.12 The Distributors will need to amend their billing systems to cater for these new tariffs and the use of RAG and BYG in preference to the Settlement time pattern regimes and for the Suppliers to determine what level of validation they require. This arrangement is currently in place for those DNOs who have delinked tariffs.

1.13 There will be no impact on settlements, but it does allow for Suppliers to introduce new innovative tariffs based on time of day to those customers with smart meters installed without the need to move NHH to HH settlements. This therefore introduces such arrangements earlier while the issues surrounding HH settlements are resolved through open governance and the industry progresses the mandating of HH settlement in line with the Ofgem timetable.

1.14 This change proposal therefore delinks DUoS billing for NHH customers (based on the mix of profiled and actual HH data) from Supplier billing data which will over time be based on actual HH data from smart meters. As Suppliers start to use the HH settlement processes for these customers it will be a seamless process.

1.15 There may be a risk to Suppliers relating to the validation of data dependent upon the billing arrangements introduced by Distributors who do not have a de-linked solution in delivering this Change Proposal.

Authority Send-Back Letter

1.16 The Authority referred DCP 268 back to the DCUSA Panel in a letter dated 20 October 2017, noting that the impacts of DCP 268 on charges for embedded generators had not been considered fully; and that the implementation date required further consideration based on Party votes. The Panel subsequently sent this back to the Working Group for further consideration.

1.17 The Working Group have provided further information under the headings 'Post Authority Send-Back' in the following Sections:

- Section 4: Solution
- Section 5: Relevant Objectives
- Section 6: Impacts and Other Considerations
- Section 7: Implementation
- Section 8: Legal Text

2 Governance

Justification for Part 1 Matter

2.1 DCP 268 is classified as a Part 1 Matter as it will impact both Distributor and Supplier Parties through amendments to the CDCM and therefore will go to the Authority for determination.

3 Why Change?

Background of DCP 268

3.1 On 26 June 2014, the Competition and Markets Authority (CMA) published its '*Notice of provisional findings*'[5] of its Energy Market Investigation stating that the *"The absence of a firm plan for moving to half-hourly settlement for domestic and the majority of microbusiness electricity customers and of a cost-effective option of elective half-hourly settlement is a feature of the markets for domestic and SME retail electricity supply in Great Britain that gives rise to an AEC".*

3.2 On the 07 July 2015, CMA published their *'Notice of Possible Remedies'*[6] advising that *"within a reasonable timetable, half hourly consumption data could be used by domestic and SME electricity suppliers to settle electricity for customers falling into profile classes 1 to 4. This approach to settlement would give electricity suppliers an incentive to offer innovative time-of-use tariffs* to*

[5] https://assets.digital.cabinet-office.gov.uk/media/559aacbee5274a1559000017/EMI_Notice_of_PFs.pdf

[6] https://assets.digital.cabinet-office.gov.uk/media/559aac8eed915d1592000023/EMI_Remedies_Notice_-_Final.pdf

encourage peak load shifting, reducing the overall costs of generating and supplying electricity to customers".

3.3 In December 2015, Ofgem issued a consultation[7] on *'Half- Hourly (HH) Settlement – The Way Forward'* which set out their intention to reform the electricity settlement arrangements to include facilitating Suppliers settling their domestic and smaller non-domestic electricity customers on a HH basis. HH settlement is initially proposed to be on an elective basis with a future expectation that all Suppliers will be mandated to settle their customers on a HH basis.

3.4 Ofgem issued a conclusions paper on elective HH settlement[8] in May 2016, which focussed on removing the perceived barriers to cost-effective elective HH settlement, and aims to have largely completed this work by early 2017, with the aim to help make a decision on mandatory HH settlement during 2018. Within this document it stated that they did not think there were any other immediate barriers to elective HH Settlement from the distribution charging arrangement, and went on to recognise that this change proposal would harmonise NHH and HH arrangements. However, it also indicated that the amount a NHH customer pays in distribution charges could still change on a move to HH Settlement, due to the switch from profiled to actual data.

3.5 Under the DCMF MIG, Issue 81 was raised on the use of HH data for DUoS charges. The group concluded that the:

- CDCM could be simplified by not accommodating the historic NHH charge structures;
- Moving to HH settlement DUoS charging will simplify the billing framework and remove barriers for customers moving between NHH & HH settlement;
- Enables innovative NHH retail tariff structures; and
- Removes risk and complexity for all industry participants.

3.6 DCP 268 has been raised by Northern Powergrid and seeks to facilitate a transition to HH settlement for NHH customers by moving to a time band charging basis, based on the HH (profiled) data used in settlement

4 Solution

DCP 268 Assessment

[7] https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-settlement

[8] https://www.ofgem.gov.uk/system/files/docs/2016/05/elective_hhs_conclusions_paper.pdf

4.1 The DCUSA Panel established a Working Group to assess DCP 268. This Working Group consisted of DNO, IDNO, Supplier, Consultant, Code Administrator representatives and an Ofgem observer. Meetings were held in open session and the minutes and papers of each meeting are available on the DCUSA website – www.dcusa.co.uk.

4.2 The Working Group considered that through the introduction of smart meters, an increasing amount of HH data is available for use in settlement which enables more accurate settlement and DUoS charging. It is recognised that the barriers to utilising HH data should be removed. The ground work for facilitating this change has been laid through recent modifications such as DCP 179[9] and P300[10] which introduced the:

- the Time of Use (ToU) RAG aggregated tariffs into the CDCM for domestic and small non-domestic customers; and
- the provision though settlement of aggregated consumption data summed by RAG time bands.

4.3 The current tariff structure within the CDCM contains a range of different tariffs which are dependent on whether the MPANs are settled on a HH or NHH basis. HH settled customers are charged under the RAG arrangements while the Unmetered Supplies (UMS) HH customers are charged under Seasonal Time of Day (SToD) BYG arrangements. The RAG & BYG time bands are DNO specific and intended to give forward looking cost signals.

4.4 This CP is seeking to transition all existing NHH metered customers on to the RAG arrangements and all NHH UMS customers onto the BYG arrangements. It is only the DUoS charges between Distributor and Supplier which will change. This change does not necessarily require any change to the tariff structure that the Supplier charges to retail customers but will allow the Supplier to introduce innovative retail tariffs if they so wish to those customers with smart meters installed without the need to move for NHH to HH settlements.

4.5 For example, a Supplier may wish to develop a retail tariff offering “free” electricity on a Saturday and identify the consumption during this period via a smart meter. The Supplier could then establish SSC & TPRs resulting in the consumption for Saturday being identified separately from other days of the week. Under the current DUoS charging arrangements the Supplier will incur the average day/night DUoS charge for all the consumption throughout the week, including Saturday, on a single rate which is a weighted average of the RAG charges for that distribution area. Under this proposal the consumption on the Saturday would be charged to the Supplier on a RAG basis, which on a Saturday for all Distributors avoids any red charges. As a result, the DUoS charges will be reduced.

[9] DCP 179 ‘Amending the CDCM tariff structure’

[10] P300 - Introduction of new Measurement Classes to support Half Hourly DCUSA Tariff Changes (DCP179)

4.6 The Working Group considered the question of how to transition from NHH DUoS customers to RAG or BYG tariffs by the use of aggregated HH settlement data and agreed that:

- All DUoS tariffs to be on RAG (or BYG) basis; and
- Billing of Suppliers by Distributors will be as per the status quo, i.e. MPANs in Measurement Classes C, D and E on a site-specific basis. MPANs in Measurement Classes A, B, F and G on an aggregated basis.

4.7 The Working Group considered how this change would impact upon the billing of these customers. On the introduction of DCP 179 and P300, the Balancing & Settlement Code (BSC) instigated a process to create pseudo data within the D0030[11] dataflows which are provided to the respective Distributor and Supplier. This information is already used to support the DUoS charging of the aggregated tariffs with effect from November 2015. The Working Group proposed to utilise and extend this existing framework (introduced as a result of these two change proposals) to support the extension proposed under this DCP.

DCP 268 Consultation One

4.8 The Working Group carried out a consultation (Attachment 4) to give DCUSA Parties and other interested organisations an opportunity to review and comment on the proposed DCP 268 solution. The Working Group issued consultation one to DCUSA Contract Managers, the DCMF distribution list, Elexon, Gemserv, Ofgem and National Grid on 18 May 2016 to determine whether Parties:

- Agreed with the principle of the change;
- Understood how the existing tariffs were proposed to be mapped;
- Agreed with the proposed legal text changes to Schedule 16 'Common Distribution Charging Methodology' which was updated to transition all existing NHH DUoS tariffs on to the RAG (or BYG) arrangement; and
- Preferred Elexon to provide the pseudo split of consumption data or for Parties to undertake the relevant work on their billing systems for Distributor to Supplier billing purposes.

4.9 There were 18 responses received to consultation one. Nine respondents were Suppliers, six respondents were Distributors, one respondent was an Independent Distribution Network Operator, a Code Administrator (Elexon) and an anonymous respondent. The Working Group discussed each response and its comments are summarised alongside the collated consultation response in Attachment 4.

---

[11] D0030 - Aggregated DUoS Report

4.10 A summary of the responses received, and the Working Group's conclusions are set out below:

Question 1: Do you understand the intent of DCP 268?

4.11 All respondents understood the intent of the CP.

4.12 Although some respondents considered that a move to billing on HH settlement data would increase the accuracy of DUoS billing and simplify the tariff structure, some concerns were raised in regard to the system costs to implement this change.

Question 2: Are you supportive of the principles of DCP 268?

4.13 16 respondents were supportive of the principles of the CP. Two Suppliers respondents who did not state that they agreed with the principles of the change provided the following reasons:

- One Supplier respondent advised that insufficient information was provided in the consultation to allow them to determine whether they were supportive of the principles of this change.
- Another Supplier advised that although they recognise the long-term justification of this proposal, they had *"significant concerns relating to the price increases for some Off-Peak and Heating tariffs".*

Question 3: Do you have any comments on the proposed legal text?

4.14 14 respondents had no comments on the legal text. Four respondents provided feedback on the legal text, a summary of the highlights is set out below:

- Paragraph 72A: The respondent considered that *"a full impact assessment should be undertaken as the existing Aggregated tariffs for 2016/17 and 2017/18 will not be representative of the likely level of the Aggregated tariffs being proposed by this change if the intent is to remove these 'correction factors'".*

  The Working Group considered that there were two tables which contained the equalisation factors and if Clause 72A is removed, it will remove the equalisation factors. The impact assessment will need to develop a model without the equalisation factors.

- Paragraph 84: *"We do not think it is sensible for this DCP to remove the Medium Non-Domestic tariffs, especially since there is a separate Change Proposal (DCP 270) looking at the issues surrounding the removal of these tariffs. The intent of this change is simply to* *introduce RAG/BYG charges for all customers. This can be achieved whilst retaining the Medium Non-Domestic tariffs, an approach which would allow the separate issues surrounding the removal of these tariffs to be debated and consulted upon as part of DCP 270. This approach would also mean this DCP remained capable of approval even if it was decided that the Medium Non-Domestic tariffs should not yet be removed".*

The Working Group clarified that the consultation proposed that *'LV Medium Non-Domestic', 'LV Sub Medium Non-Domestic'* and *'HV Sub Medium Non-Domestic'* tariffs be mapped to the relevant HH tariff with a default capacity value of 71kVA. Based on the responses to the consultation, the Working Group considered whether these Medium Non-Domestic tariffs should be mapped to profile classes 3-4 rather than 5-8 and as such move onto the aggregated non-domestic tariffs. The Working Group highlighted that the approach proposed may not be necessary if DCP 270 was approved which had been raised to remove these tariffs from the CDCM on the 01 April 2018.

Post Consultation Note: DCP 270 'Removal of HV Medium Tariff from CDCM' was raised to remove the HV Medium Non-Domestic tariff and LV and LV Sub Medium Non-Domestic tariffs from the CDCM during the progression of DCP 268. This CP was rejected on the 16 November 2016 as Ofgem recognised that there may be Customers that had not been transitioned in accordance with the BSC P272[12] requirements from the traditional metering to profile class meters 5-8 by the 01 April 2018 and that these tariffs may still be required.

Question 4: Please provide your views on the proposed mapping of tariffs set out in Attachment 4?

4.15 The majority of respondents considered that the tariff mapping proposed seemed logical and appropriate. However, some Supplier respondents did not agree with the approach proposed for the medium non-domestic tariffs with one respondent suggesting that an assumed default capacity value of 71kVA was punitive.

4.16 The Working Group highlighted their response to the previous question where they proposed to map these tariffs to the non-domestic aggregate whole current tariff.

4.17 One respondent requested clarity on the tariff mapping for a Small Non-Domestic site with CT metering which is currently mapped to a LV Non-Domestic Non-CT Aggregate tariff as the name implies that the site does not have CT metering.

[12] DCP272 - Mandatory Half Hourly Settlement for Profile Classes 5-8

4.18 The Working Group noted that there is no distinction between CT and WC and agreed to amend the tariff name to LV Non-Domestic Aggregate to remove ambiguity.

Question 5: Do you agree with the proposed approach to the mapping of off peak tariffs as set out in paragraph 5.5 of this consultation?

Respondent Party Type	Agree	Do Not Agree	Part Agree	Insufficient Information	No Comment	Comment Provided
Supplier	5	0	0	1	2	1
DNOs	5	0	1	0	0	0
IDNO	1	0	0	0	0	0
Anonymous	0	0	0	0	1	0
Code Administrator	1	0	0	0	0	0
Total	**12**	**0**	**1**	**1**	**3**	**1**

4.19 12 respondents were supportive of the approach proposed to facilitate the correct DUoS billing by mapping the off-peak tariffs (for related MPANs) using a unique Line Loss Factor Class (LLFC) and Standard Settlement Configuration (SSC) that has no fixed charge.

4.20 One respondent who was supportive of the approach advised that *"failure to take this approach would likely cause parties (DNOs and Suppliers) billing issues, as primary MPANs (with a fixed charge) and the off peak (without a fixed charge) would otherwise use the same LLFC. This approach separates the two tariffs*".

4.21 Another respondent requested that DNOs retain the existing settlement codes (SSC, Time Pattern Regime (TPR), and LLFC) whenever possible due to their extensive use in the industry and be provided of advance notice if the code changes. The Working Group agreed that they would not be changing settlement codes for customers.

4.22 The Working Group discussed the responses and agreed to take this approach forward as part of the final solution.

Question 6: Please advise whether you have a preference for Elexon to provide the pseudo split of consumption data or for Parties to undertake the relevant work on their billing systems?

Respondent Party Type	Elexon	DNOs	Comment	No Comment	Insufficient Information
Supplier	7	1	0	1	1
DNOs	3	2	1	0	0
IDNO	1	0	0	0	0
Anonymous	0	0	0	0	0
Code Administrator	0	0	1	0	0
Total	**11**	**3**	**2**	**1**	**1**

4.23 The majority of respondents were supportive of Elexon centrally providing the pseudo split of consumption of data with only three respondents preferring for DNOs to undertake this work on their billing systems.

4.24 One respondent highlighted a concern that all of the existing NHH settlement data is already on the D0030 so by adding it again it causes a risk of double counting. This respondent did not consider that a profile class of zero for all HH aggregated and NHH settled data to be appropriate and that to extend the use of dummy Market Domain Data (MDD) across all NHH MPANs needs to be carefully considered.

4.25 Following consideration of the responses, the Working Group agreed that insufficient detail was provided to allow Parties to determine whether it was more beneficial for Elexon to provide the pseudo split of consumption data or for Parties to undertake the relevant work on their billing systems. The Working Group agreed to carry out a Request for Information (RFI) on an impact assessment on the proposed solutions which would include utilising the BSC dataflows, the Distributors billing system and a Suppliers validation system.

4.26 Members agreed to undertake detailed process mapping considering what appears in the dataflows and listing the advantage and disadvantages of the approaches proposed for consideration by Parties.

Question 7: Which DCUSA Charging Objectives does the CP better facilitate? Please provide supporting comments.

1. 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

2. that compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)

3. that compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business

4. that, so far as is consistent with Clauses 3.2.1 to 3.2.3, the Charging Methodologies, so far as is reasonably practicable, properly take account of developments in each DNO Party's Distribution Business

5. 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. Should there be Service Level Agreements (SLAs) in place for EDNOs to verify the content of the customer inventory submissions?

Respondent Party Type	Objective 1	Objective 2	Objective 3	Objective 4	Objective 5	Undecided /Not Applicable
Supplier	0	4	7	0	0	1
DNOs	0	4	5	0	0	1
IDNO	0	0	0	0	0	1
Anonymous	0	0	0	0	0	1
Code Administrator	0	1	1	0	0	0

Total	0	9	13	0	0	4

4.27 The majority of respondents considered that DCUSA Charging Objectives 2 and 3 were better facilitated by the change for the following reasons.

Objective Two

- This change allows greater flexibility in the supply industry to offer time of use tariffs. The development by suppliers of innovative tariffs will facilitate competition in electricity supply;
- The provision of appropriate cost signals to encourage efficient use of the distribution system; and
- The wider use of time band pricing will make DUoS pricing more transparent, which will influence suppliers to respond to the cost signals. Suppliers will be able to continue with the status quo if they wish, as the new tariffs should result in the same total DUoS charge for the average customer for the majority of tariffs.

4.28 1 respondent considered that objective two was not better facilitated as customers will not be able to respond to pricing signals if they are billed based on profiled data. This change would not encourage users to increase their off-peak consumption or reduce their peak consumption but will allow Suppliers a broader understanding of the time-based charging bands. Therefore, this will not benefit consumers or distributors until such a time as real consumption data can be used in settlement and billing.

4.29 This respondent also did not see how this change increased cost reflectivity under Charging Objective three as this CP allocates a time band charge not based on actual data. Consumers who use the system at different times will not be charged different prices to use the system and so there cannot be considered to be any increase in cost reflectivity in these charges.

4.30 The Working Group noted that the majority of respondents considered that Charging Objectives 2 and 3 are better facilitated by this CP. Please refer to Section 5 of this report for the Working Group's rationale on which DCUSA Charging Objectives are better facilitated by this change taking into consideration the request for information and the second consultation that resulted from this consultation

Question 8: It is proposed that DCP 268 be implemented on the 01 April 2018. Do you agree with this approach?

Respondent Party Type	Agree	Do Not Agree	Comment	Insufficient Information
Supplier	7	1	0	1
DNOs	4	1	1	0
IDNO	0	0	1	0
Anonymous	0	1	0	0
Code Administrator	1	0	1	0
Total	**12**	**3**	**2**	**1**

4.31 The majority of respondents to this question were in agreement with the proposed implementation date of the 01 April 2018. A number of Supplier respondents, although supportive of the implementation date, raised concerns about the short timescales prior to the next round of DUoS charges being released which may adversely affect their ability to update their customer tariffs and the minimising of any customer cost disturbance.

4.32 Respondents who were not supportive of the implementation date provided the following comments:

- "No. The tariffs for 2018/19 will be set in December 2016; we do not think that this allows sufficient time for us to amend our forecasting models to facilitate reasonable consumption input data for CDCM table 1053. We would prefer DCP268 to be implemented on 1st April 2019".

The Working Group agreed to take this in to consideration following the outcome of the RFI on the impact assessment.

- "No. It should be implemented on the same date as mandatory Half Hourly settlement for Profiles 1-4".

- "No. This gives suppliers less than 6 months (Since charges will be published for April 18 and beyond in December 16) to make changes to systems/process that quote DUoS charges beyond April 18. With other concurrent regulatory changes such as Project Nexus and faster switching also needing to happen, it's important that implementation dates consider the impacts this will have on these changes too. We propose an implementation date of 01 April 2019 to give suppliers the opportunity to manage all of the changes successfully. Plus suppliers may have created contracts where DUoS costs are fixed on a NHH basis beyond April 18 and experience friction if DUoS is settled on a HH basis thereafter".

4.33 The Working Group noted that there will be 15 months notification of a change to charges and agreed that the deadlines are tight but agreed to aim for a 01 April 2018 implementation date.

4.34 **Post Consultation note:** Following a further RFI and consultation to develop an effective solution to this change, the implementation date was amended to the 01 April 2019

Question 9: Are you aware of any wider industry developments that may impact upon or be impacted by this CP?

4.35 11 respondents were not aware of any wider industry development that may impact or be impacted by this CP that the Working Group had not already raised within its consultation. Other respondents noted the CMA's and Ofgem's support for a move to half-hourly settlement, any stumbling blocks associated with the *P272 'Mandatory Half Hourly Settlement for Profile Classes 5-8'* and DCP 270 *'Removal of HV Medium Tariff from CDCM'* as having a potential impact on this change.

4.36 1 respondent highlighted a recent report published by Citizens advice on 'Tackling Tariff Design - managing the tariff transition' for the Working Group to consider.

4.37 The Working Group noted the responses relating to the CMA Ofgem's work in this area and agreed that this Change Proposal would support that work and considered the Citizens Advice document was more related to retail tariff rather than DUoS tariffs.

Question 10: Are there any alternative solutions or unintended consequences that should be considered by the Working Group?

4.38 9 respondents were not aware of any alternative solutions or unintended consequences for the Working Groups consideration with one respondent advising that there was insufficient information in the consultation for them to answer this question. A summary of the responses is provided below:

- 1 Supplier respondent noted that this change provides for elective HH settlement and advised that Suppliers may only move accounts to being HH settles if their usage patterns mean lower DUoS bill. This respondent asked the Working Group to consider whether if this is the case, a forced method of conversion should be considered.

- Another Supplier respondent highlighted concerns over pricing volatility and receiving sufficient notice of the implementation of this change.

- A DNO respondent advised that "this change will increase the proportion of DNO revenue which is recovered from the red time band. This could cause issues if, in the future, time of use supply tariffs become widespread for end customers. If a large number of customers were to respond in the short term to such time of use tariffs by moving load away from the DNO red time band, this could lead to significant under-recovery as the change would likely occur in the period between DNO charges being set and coming into force. The increased variability of DNO revenue could lead to higher correction factor in future years. The potential impact of this will be quantifiable once an impact assessment is produced; at present we believe the benefits of the change outweigh this potential issue".

4.39 The Working Group noted the responses.

Consultation One: Working Group Conclusion

4.40 The Working Group agreed that insufficient detail was provided in the initial consultation to allow Parties to determine whether it was more beneficial for Elexon to provide the split of consumption data in to the distribution time bands or for Parties to undertake the relevant work within their internal and billing systems. The Working Group agreed to carry out an RFI on a set of proposed options identified under paragraph 4.41 and 4.42 below.

DCP 268 Request for Information

4.41 Following the previous consultation, it was noted that if the preferred option was for Elexon to provide the pseudo split of consumption data, then a change to the BSC would need to be raised with a list of detailed changes required to the D0030 dataflow. The Working Group undertook detailed process mapping in order to provide the data that would appear in the dataflow and list the advantages and disadvantages of the approaches proposed.

4.42 The Working Group carried out a RFI between the 31 August 2016 and the 21 September 2016 on the proposed centralised and Distributor solutions which include utilising the BSC dataflows, the Distributors billing system and a Suppliers validation system.

4.43 The four variants to the Centralised approach are set out below:

- **Option 1a** – aggregate the settlement combinations to the proposed new Distribution tariffs.

- **Option 1b** – aggregate the settlement combinations to the proposed new Distribution tariffs but subdivide the LV Domestic Aggregated tariff by HH aggregation and NHH aggregation and separate the non-domestic aggregated tariffs by NHH and HH.

- **Option 1c** – aggregate the settlement combinations by HH aggregation and NHH profiles (Profile Classes (PC) 1-8 and maintain the difference between metered and unmetered profiles).

- **Option 1d** – retain the existing settlement combinations but replace the TPR of each combination with the distributor time band TPRs.

4.44 The **Distributor approach** proposed utilises the existing profiled HH consumption values contained in the D0030 data flow to determine the units to be charged under the NHH DUoS time of day (year) tariff.

4.45 There were 13 responses received to the RFI. 6 respondents were Suppliers, 6 were Distributors and 1 was an IDNO. The Working Group discussed each response and its comments are summarised alongside the collated RFI responses in Attachment 5.

A summary of the responses received, and the Working Group's conclusions are set out below.

Question 1: Please advise which is your preferred option? Please provide your rationale inclusive of any financial, resource or system impact or restriction.

Options	1A	1B	1C	1D	Non-Centralised Approach	No preference
DNO	0	0	0	1	4	1
Supplier	0	0	1	2	3	0
IDNO	0	0	0	1	0	0
Total	**0**	**0**	**1**	**4**	**7**	**1**

4.46 Some Parties clarified their position in relation to their preferred solution at the 28 September Working Group meeting. The above table summarises respondent's preferences for each solution proposed in the RFI.

4.47 A summary of comments provided on the rationale behind respondents preferred options is set out below:

Option 1c – Aggregate the Settlement Combinations by HH Aggregation and NHH profiles (Profile Classes (PC) 1-8 and maintain the difference between metered and unmetered profiles).

4.48 1 respondent preferred Option 1C on the basis it was the only option that gives PC 1 and 2 level transparency and that the PC split on the D0030 negates the requirement to include pseudo PCs which the respondents believed would complicate and add unnecessary systems developments to the UoS billing processes.

4.49 The Working Group noted that under this solution there would be a pseudo LLFC, TPR and SSC combination.

Option 1d – Retain the existing settlement combinations but replace the TPR of each combination with the distributor time band TPRs.

4.50 4 respondents preferred Option 1d and provided the following rationale for their choice:

- *"Although this is likely to have the most significant system impact internally; as the industry continues to move towards HH Settlement, option 1d better facilitates this move and ensures that costs are more reflective of the actual DUoS charges. This option also gives the best transparency for the validation of DUoS Charges".*

- *"It has the following benefits; it retains each settlement combination, apart from the TPR, both Suppliers and Distributors receive the same data, likely to be a simpler change than options 1a, 1b and 1c and of the Centralised options it is closest to the 'status quo', so likely to have lowest implementation cost".*

- *"Option 1d would be our preferred option, as it utilises the approach already used successfully following the introduction of the new Measurement Classes (F & G). This method would have zero costs…., and offers the benefit of speedy implementation whereas the other solutions would all require system and process changes".*

- This second preference solution requires the least number of changes on the D0030, only replaces the TPRs with the distributor's pseudo TPRs; Distributors can apply RAG unit charges without using de-linking; retains the relationship between the D0030 data and MPRS data; it gives parties detail at the lowest possible level; is a simple change and has the lowest implementation cost for the centralised options for this respondent.

Distributor Approach

4.51 Some respondent's comments on why they preferred the Distributor approach are set out below:

- *"Our preferred option is Option 2, - Under this approach the data provided to parties in the D0030 & D0314 would remain the same, which allows Distributors control over how charges are applied and would not require any central system changes. The link between data on the D0030 and MPRS is retained and there is no risk of data being missed off the data flows due to incomplete mapping".*

- *"The distributor approach is the preferred option, this has the least impact both financially and on systems and it retains the reporting flexibility as current".*

- *"In effect this would be the introduction of De- linking which ----- already does within our 2 midland DNO areas. However to adopt de-linking we believe there would be a change to schedule16, para 130 of the DCUSA required".*

- *"It also allows Billing of invalid combinations on a default tariff".*

4.52 Following consideration of the responses, the Working Groups voted on the preferred option which resulted in eight members voting for the non-centralised approach and four members voting for the centralised approach with three of those four members voting for Option 1D.

Question 2: Please provide your comments on all options (Centralised approach options 1a-d and the Distributor approach) based on your priority of preference for the solution proposed? Please provide your rationale inclusive of any system impacts.

4.53 A selection of comments on each of the Option 1 a-d and the Distributor approach are set out below:

Option 1a

- *"Loss of transparency of settlement combination costs; The use of pseudo LLFCs and PCs for billing adds complexity to charging arrangements; Requires transitional arrangements which could add to system cost and charging complexity".*

- *"Although the decrease in size of the D0030 content would be welcomed, using this method we require a complex level of de-aggregation internally with the HH and NHH volumes being aggregated in the LV classes, in order to validate our DUoS charges".*

- *It might be a more straightforward D0030 flow change. Less information will be included whilst still reaching the outcome required. We are concerned that this option may require further changes when full HH settlement is considered and therefore it cannot be considered to be a viable option going forward.*

Option 1b

- Maintains *"the NHH and HH split is important, however with this option we would require a complex level of de-aggregation internally in order to validate our DUoS charges".*

- *"Unusable - 1b – Maintains the NHH/HH split but uses pseudo PC in the D30 flow, causing reporting issues – High system cost to change, large resource and cost to change reporting for pseudo PC's".*

- *"Option 1b – This option appears to be a more balanced solution, however, there are concerns that have not been addressed yet with regards to the SVAA allocating volume to tariffs".*

Option 1c

- *“Option 1c: This option provides a better level of de-aggregation by utilising PC’s as segments in the D0030, which would enable a more simple DUoS validation logic”.*

- *“Workable at cost - 1c – Maintains the NHH/HH Split by PC which is required for reporting – High System cost to change”*

Option 1d

- *“As stated above we are supportive of option 1d, as this approach does not aggregate the data in the same way, but does utilise an existing approach. By using the existing LLFC/PC but with the red, amber, green time bands and black, yellow, green time bands, suppliers are given visibility of the volumes and customer numbers for any LLFC/PC and can reconcile those”.*

- *“Option 1d – With the data split to this level of granularity this option has the potential to increase the size of the D0030, granularity that is not necessary required to achieve the goal of billing DUoS charges”.*

- *“Option 1d has a smaller impact then 1a, b,c on the system and appears to only require pseudo TPR’s ,this retains the link between data on the D0030 and data in MPRS. There is a risk that data is missed from the revised D0030 and any future changes to the way that data is mapped could require additional BSC modifications”.*

General Comment on Centralised Options

- *“Options 1a, 1b and 1c have similar impact on DURABILL……... If any of options are selected, changes will be required to DURABILL to allow the use of pseudo PC, LLFC and SSC values. The required changes would be similar to those made when aggregated HH Tariffs were introduced. As per current HH aggregated data billing, no validation against MDD will be possible. As the data in the D0030 would no longer represent actual combinations of PC, LLFC and SSC, there would be no way to link the data in the data flow back to MPRS. Hence it would no longer be possible to use some DURABILL reports. Each of these options would require Elexon to use mapping data, and that where mapping data does not exist, there is a risk that data is missing from the D0030 or D0314 data flows and that income cannot be recovered”.*

Distributor Approach

- *“Priority 2 - Distributor Approach 2: This option appears to require the least amount of system changes to implement. Existing RAG time mappings for all DNO’s are able to be utilised along with additional tariffs, which will also facilitate a simpler way to validate NHH DUoS charges. However not being centralised, there may be delays in receiving data based on revised settlement data and we will more than likely see differences in how each DNO interprets de-aggregates the D0030 data”.*

- *“Option 2 – This approach has the least system impact and provides the most transparent data as the existing settlement combinations will continue to be used. Suppliers will be able to validate the data in the D0242 dataflow using the published Distributor time bands”.*

4.54 The Working Group noted that if a centralised approach was to be recommended, a BSC change would need to be raised. In regard to the concern that pseudo industry data would not be contained in MDD for validation purposes, the Working Group agreed that all Parties impacted would need access to this data and how it is mapped.

4.55 The Working Group agreed to summarise the cost impact to preferred Options 1c, 1d and 2 to determine the cost of the options and provide to Parties in the next consultation.

Question 3: What do you consider is the development timescale required for each of these options? Please provide your rationale.

4.56 8 respondents considered that they could make the relevant changes to their billing system in line with the implementation date of the 01 April 2019. For all approaches proposed, two respondents advised that the project would take 4-6 months or 12 months. One respondent provided a separate implementation timescale depending on the option taken forward, with a 6-12-month implementation timescale for Option 1a-d and 3-6 months for the Distributor approach.

4.57 The Working Group agreed that the timescales to process and implement a BSC change for a centralised approach will determine the length of time available to Parties to develop a system solution. It was noted that Parties will be provided with a minimum 15-month notification period prior to any change being implemented.

Question 4: Distributors: What approaches will you be taking to the LLFCs for each of these options? Please refer to paragraph 4.4 of this RFI.

4.58 7 respondents had no comments, or the question was not applicable to them. Respondents who preferred the Distributor approach and the centralised option 1d advised that there is no need to create a new LLFC for these options. For the Centralised Option 1a-1c, there was a split with some respondents proposing to use pseudo LLFCs with a mapping provided to Elexon and those proposing to create a new LLFC.

4.59 For the pseudo LLFCs, it was noted that it would result in a loss of transparency as LLFCs used for billing would no longer be registered in MDD. This would in turn cause problems with MDD and gateway validation of files received. For the new LLFCs, one respondent advised that they would create a new LLFC for each new tariff but would not be prepared to change every LLFC to a new LLFC. One respondent proposed that the new LLFCs be added to the MDD catalogue.

4.60 1 IDNO respondent on review of this question, advised they were supportive of Option 1D due to the reduced pseudo data requirements. For the Distributor approach, they use a system called pebble which makes the cost of implementing the Distributor approach less favourable.

4.61 The Working Group noted the responses.

Question 5: If DCP 268 is implemented with central system changes (i.e. any of options 1a-1d) an approach will be required for transition to the new arrangements. Please advise which transitional approach option, i, ii, or iii is your preferred approach? Please see Section 5 of this RFI.

Transitional Option			
Party Type	Option i	Option ii	Option iii
DNO	2	4	0
Supplier	0	2	1
IDNO	0	0	1
Total	**2**	**6**	**2**

4.62 The above table sets out Parties preferred Transitional Option for the centralised approach options 1a-1d that were provided in the RFI. 4 respondents suggested an alternative transitional Option iv *"where the version of the D0030 remains the same, and Elexon populates the dataflows with the current Settlement Class data for Settlement Dates before the implementation date, and with only aggregated data for Settlement Dates on or after the implementation date".*

4.63 The Working Group considered that this new Option (iv) has the advantage of not having to go through the process of raising a change that goes to MDB. This reduces the number of changes to be co-ordinated - MRA, BSC and DCUSA changes.

Question 6: If DCP 268 is implemented with the Distributor approach, are you able to cater for the transitional arrangements as detailed in paragraph 6.5?

4.64 Respondents advised that they could cater for the transitional arrangements if the Distributor approach will be implemented. The majority of respondents can accommodate the transitional arrangements with no change or a small change to their systems. One of these respondents advised that they the Distributor approach would require large scale changes to their systems. One of these respondents advised that they *"would be required to introduce a new process for the new data (in order to aggregate in). Further processes would need to be developed to support the utilisation of the existing flow for this purpose".*

4.65 1 Distributor who used the Durabill system advised that the *"DURABILL tariffs are already applied at a settlement date level so no changes would be required to cope with the transition from TPR based tariffs to de-linked tariffs".*

4.66 The Working Group noted that currently 2 Distributor areas are already de-linked and sending the data in the Distributor option, so Suppliers are already receiving the fully de-linked or a combination of default TPR and supported TPR in WPD distribution licence areas.

Question 7: Are there any alternative solutions or unintended consequences that should be considered by the Working Group?

4.67 4 respondents had no comments. Some respondents highlighted that if any of the Option 1 solutions were selected, changes may need to be made to software processing incoming data flows from the Data Transfer Network. There is a concern that these data flows will contain data that is not in MDD and may fail validation, resulting in a need to turn off validation for these flows.

4.68 The Working Group considered that if the party considers that there is a need for a change to MDD that it is raised or alternatively it can form part of a change to the BSC if the centralised option is supported.

4.69 A number of respondents advised that if the *"Distributors approach is adopted, the DNOs may want to consider whether changes can be made to the provision of Profile Class 0 data in the D0030 and D0314. If de-linking is used for all NHH data on the flows, distributors may want to start doing this for the Profile Class 0 data instead of ELEXON".*

4.70 The Working Group noted that the PC data is already split in to RAG. The intent of this CP is specific to NHH data.

4.71 1 respondent proposed a transitional solution for Option 1d through the utilisation of "a pseudo SSC and TPR (which follows the approach taken with DCP179 and P300), and not just a pseudo TPR as specified in the suggested approach for option 1d in the RFI. A significant benefit of this approach would be that fewer combinations would need to be included in the D0030 to Distributors".

4.72 The Working Group noted that this option may be an issue for IDNOs as they use a combination of LLFC and SSC to determine the tariff. It would make the mapping more complex than the current suggested 1D option

Request for Information Conclusions

4.73 On review of the responses on the Centralised approach, the Working Group noted:

- **Option 1a** - that respondents did not support Option 1A as the mixing of actual HH consumption data with HH profiled data reduces transparency and does not offer enough visibility for reporting or validation purposes.

- **Option 1b -** that respondents did not support Option 1B as the use of pseudo LLFCs and PCs for billing adds complexity to charging arrangements and there is a loss of transparency of settlement combination costs.

- **Option 1c** – that the majority of respondents did not support Option 1c as the introduction of pseudo LLFC, TPR and SSC could complicate the validation process of data flows.

- **Option 1d** – that the majority of respondents did not support Option 1d but it is noted that it has a smaller impact on the system as it builds on existing functionality successfully used for P300. It requires the least number of changes on the D0030, only replacing the TPRs with the distributor's pseudo TPRs. Distributors can apply RAG unit charges without using de-linking. It retains the relationship between the D0030 data and MPRS data. It gives parties detail at the lowest possible level.

4.74 On review of the responses on the Distributor approach, the Working Group noted:

- **Distributor approach**- the majority of respondents supported the Distributor approach and advised that this approach provided the least impact on their internal systems and as a result the lowest implementation cost. The DNO's existing RAG time mappings are able to be utilised along with additional tariffs, which will facilitate a simpler way to validate NHH DUoS charges. A DNO respondent noted that this solution would require significant system and process changes to take place to their internal systems. A Supplier respondent considered that it would provide the greatest flexibility in reporting of all the options.

4.75 Those respondents who provided a summary of the cost to implement the options set out above advised:

Respondent	Option 1a	Option 1b	Option1c	Option 1d	Distributor Approach
Distributor Respondents					
1					£30k and an additional £30 k for the company
2	£35k to £60k	£25k to £45k	£80k to £110k	£20k to £40k	£25-£30k for Durabill changes
3					£25 to £30k for Durabill changes
4				0	
Supplier Respondents					
5					£6,250.
6	>£100k	>£100k	>£100k	>£70k	

<u>Transitional Arrangements</u>

4.76 If DCP 268 is implemented with central system changes an approach will be required for transition to the new arrangements. Settlement days prior to the 'effective from Settlement Date' for the new approach would require the existing D0030 data until completion of all associated Reconciliation runs. Elexon identified the following options:

i. Add the new aggregations into the existing D0030, for the transition period, and let the Distributor identify the appropriate data for the Settlement Date. This option has the risk of double counting. Following the transition period, the existing D0030 data can be removed from the flow;

ii. Define a new flow version. Reconciliation runs for Settlement days prior to the *'effective from'* settlement date for the new approach would get the old flow version of the D0030. Reconciliation runs for Settlement days' post to the *'effective from'* settlement date for the new approach would be provided on the new version. This option will result in system costs to accommodate the new data. No change required following transition as Distributors will only receive the new flow version; or

iii. Define a new flow. Reconciliation runs for Settlement days prior to the *'effective from Settlement Date'* for the new approach would get the D0030. Reconciliation runs for Settlement days' post to the *'effective from Settlement Date'* for the new approach would get the new data flow. This new data flow could be defined to remove any redundant items not required for the aggregation (e.g. PC). This option will result in system costs to accommodate the new data. Following the transition, the D0030 will be discontinued.

4.77 2 respondents provided the cost of the Centralised Options in relation to the Transitional Approach for Options 1A – 1C. The Distributor respondent who chose to provide their costs in this format also provided a cost for Option 1D as set out below:

Option 1A- 1C		
Transitional Options	**Supplier Respondent**	**Distributor Respondent**
Option i	10-12k, plus additional internal additional IT costs + Testing of System, approximately £10k to 15k	£45,000 - £60,000
Option ii	10-12k, plus additional internal additional IT costs + Testing of System, approximately £10k to 15k	£35,000 - £45,000
Option iii	20-25k, plus additional internal additional IT costs + Testing of System, approximately £10k to 15k	£90,000 - £110,000
Option iv[13]	10-12k, plus additional internal additional IT costs + Testing of System, approximately £10k to 15k	£35,000 - £40,000

Option 1D	
Transitional Options	**Distributor Respondent**
Option i	£35,000 - £40,000
Option ii	£25,000 - £30,000
Option iii	£80,000 - £95,000
Option iv	£20,000 - £25,000
Option 2/Distributor Approach	
Distributor Respondent	
£35,000 - £40,000	

4.78 The Working Group concluded that the PC would need to be populated with a pseudo PC in the D0030 dataflow for Options 1A, 1B and 1C. This introduces additional complexity and could cause validation issues. The Working Group considered the cost impact on parties and agreed to not proceed with Option 1A – 1C.

[13] See para 4.61

4.79 The Working Group considered that Option 1D provides the least level of pseudo data and the only change is related to TPRs whilst other options within Option 1 relate to pseudo LLFC's, SSC's, PC's and TPR's. Option 1D would be cheaper to implement than Options 1A to 1C as it builds on the existing infrastructure introduced by P300.

4.80 On review of the Distributor approach, it was noted that currently two Distributor areas are already de-linked and sending the data in the Distributor option so Suppliers are already receiving the fully de-linked or a combination of default TPR and supported TPR in these distribution licence areas. Distributors who use the Durabill billing system are quoting costs of approximately £30,000 - £40,000 for the implementation of the Distributor approach. One Distributor who is known not to use this system advised that this solution would require significant system and process changes and advised that they preferred Option 1D transitional option iv.

4.81 Taking into account the RFI responses and after further discussions on the merits of each option (including the new transitional option iv), the Working Group agreed by majority that the preferred implementation approach for DCP 268 is the Distributor Approach. However, since the transitional option iv was proposed by respondents to the RFI and so not all Parties were given an opportunity to comment on this transitional option, the Working Group decided to offer Parties the opportunity to comment on Option 1D transitional option iv in consultation two.

DCP 268 Consultation Two

4.82 Following consideration of the responses to the RFI, the Working Group agreed that they preferred the Distributor approach but considered that respondents had not an opportunity to comment on a solution proposed in the responses to the consultation, Option 1D Transitional Option iv. The Working Group carried out consultation two on a modelling impact assessment, the proposed legal text track changed against the charging methodology pre-release and the remaining two proposed solutions.

4.83 There were 11 responses received to consultation two. 2 were Suppliers, 6 were Distributors, 1 was an IDNO, 1 was a consultant and 1 was a code administrator. The Working Group discussed each response and its comments are summarised alongside the collated consultation two responses in Attachment 6.

A summary of the responses received, and the Working Group's conclusions are set out below.

Question 1: Do you agree with the Working Group conclusion that the Distributor Approach offers the best solution for implementing DCP 268? Please provide your rationale.

4.84 9 respondents agreed that the Distributor approach offers the best solution and some of the reasons behind this choice are outlined below:

Supplier Response

- *"does not require any central system changes or costs; does not require new mappings to be submitted to ELEXON; retains the existing visibility of the Settlement combinations within the D0030; does not require the creation of new 'pseudo' Profile Classes, SSCs or TPRs; avoids invalid mapping issues; avoids issues with different dataflow versions before and after the proposed EFD of 1 April 2019; and can use existing distributor functionality in mapping the D0030 to the new tariffs".*

Consultant Response

- *"It ensures a consistent approach by Distributors. It minimises the overall costs. The DNOs using the St Clements Durabill system have previously advised that it should be able to facilitate with little or no change. The Supplier changes are to validate the Distributor charges and as such do not need to be on the critical path for implementation by 2019".*

Distributor Response

- *"This is the only option which provides the DNOs with total control over their DUOS charges and requires no central system changes or BSC changes. This is the only option which requires NO change to the existing D0030 and D0314 flows, this also has the advantage of keeping the D0030 in line with ECOES, and gives ALL parties details at the lowest possible level. It also allows DUOS Billing of invalid combinations".*

4.85 2 respondents did not agree that the Distributor approach was the best solution for implementing DCP 268. 1 IDNO respondent highlighted that *"Under the proposed solution, costs associated with amending the billing system can be shared across the majority of industry participants as they use a common billing system. In our case, we use a bespoke billing system and consequently we cannot socialise the costs of such change and therefore believe the proposed solution will not be cost effective for our business".*

4.86 A DNO respondent advised that they did *"not agree that the Distributor approach is the best solution, for the following reasons; In-efficiency as requires multiply Distributor parties to perform the same or similar calculations; Potential knock on in-efficiencies for suppliers in validating Distributor calculations; and Future market entrants would need to engage with the process – potentially an additional hurdle for market entry. In summary, we believe that the Distributor approach is too costly (multiple systems to be changed), inefficient and creates potential data inconsistencies and validation difficulties".*

4.87 The Working Group acknowledged that both of the Distributor respondents above did not use the Durabill billing system which is currently utilised by four DNOs. As the costs of implementing the DCP 268 solution on the Durabill billing system are socialised, this change will have lower cost implications for these DNOs. Members noted that the two Supplier respondents to this consultation who supported the Distributor approach did not highlight any difficulties with invoice validation.

4.88 The Working group noted the responses and made a decision after reviewing the comments on Question 2 and 3 below.

Question 2: If you have a preference for the Centralised Approach Option 1D Transitional Option iv over the Distributor Approach, please provide your rationale.

4.89 6 respondents had no comments on this question. 2 Distributor respondents had a preference for the Centralised Approach Option 1D with Transitional Option iv. The IDNO respondent referenced their response to the previous question which the Working Group addressed at this question. The DNO respondent provided the following reasons for their preference for the Centralised Approach;

- *"Utilises the already successfully proven model used by the entire industry to facilitate DCP179 and P300.*
- *Efficiency as a single party (Elexon) would be preforming the same calculations – thereby ensuring standard calculation and validation rules can be applied,*
- *Reduces complexity for suppliers in validating data.*
- *In summary, we believe that the centralised approach would deliver an industry efficient standard approach with robust data validation rules – much as has been delivered for DCP179 and P300".*

4.90 1 DNO respondent who was not supportive of this solution advised that they did *"not see value in losing transparency of settlement data".*

4.91 The Working Group noted the responses and made a decision based on Question 1 and 3 below.

Question 3: Please confirm the costs expected to be incurred under either approach.

Respondent	Distributor Approach	Centralised Approach
ENWL	£25k - £30k	
Northern Powergrid	£10k	
SEPD & SHEPD	£25k - £30k for Durabill and £40k for internal systems	£20k-£25k
SPD & SPM	£60k	£60k
UK Power Networks	£100k - £150k	

Western Power Distribution	£25k - £30k	£20k-£25k
SSE Energy Supply	£6,250	£20,000
Elexon	0	Indicative £102k - £112k

4.92 The code administrator respondent advised that *"a detailed specification for changes and an IA from the Supplier Volume Allocation Agent (SVAA) if the centralised approach were adopted. For reference the centralised system costs for P300 were £112K, and for P339 were £102K. The changes proposed under the centralised approach would appear to be more complex than either P300 or P339. A lead time of at least six months would also be required which could impact the proposed implementation date".*

4.93 After consideration of the costs and the comments on the Distributor and Centralised led approach, the majority of the Working Group agreed to progress the Distributor led approach.

Question 4: The Working Group agreed with the Parties view that site specific tariffs were not appropriate, see tariffs concerned and these will be mapped to the aggregated non-domestic tariff. Views are sought on whether this is the appropriate approach.

4.94 In the previous consultation, the Working Group proposed that the *'HV Medium Non-Domestic', 'LV Medium Non-Domestic'* and *'LV Sub-Medium Non- Domestic'* tariffs be mapped to relevant HH tariff with a default capacity value of 71kVA. Following consideration of those responses, the Working Group proposed to map these tariffs to the aggregated non-domestic tariff in consultation two.

4.95 9 respondents agreed with proposed mapping of these tariffs to the aggregated non-domestic tariff. With one respondent agreeing with the approach based on it not being possible to complete the installation of HH capable metering for the remaining PC 5-8 customers prior to the implementation date for this change.

4.96 1 DNO respondent queried the proposed mapping as they considered that *"Charging the different voltage levels on the same tariff would weaken cost reflectivity".*

4.97 The Working Group noted that there will be approximately 70,000 PC 5 -8 customers by the 01 April 2017 and this CP would only impact those that should be site specific due to CT metering. This change will be introduced by the 01 April 2019 so the Working Group expect these volumes to be low. It is a pragmatic solution until suppliers, as a consequence of their supply licence obligations and BSC obligations, ensure that these customers are migrated to the correct tariffs. There were 600 HV medium non-domestic customers in 2016 which the Working Group would expect all to have migrated by the time that this CP is implemented. These numbers have reduced substantially since 2016 / 2017 and are likely to continue to reduce.

Question 5: Do you have any comments on the proposed legal text and the inclusion within it of approved but not implemented DCP 227 impact?

4.98 9 respondents had no comments on the DCP 268 draft legal text. 1 DNO respondents advised that *"A modified version of paragraph 42A in Schedule 16 may still be necessary – we are still going to need a load and coincidence factor for the LV UMS tariff, which we believe will be calculated by aggregating data for NHH metered and pseudo HH metered UMS customers. The issue of data in settlements for NHH metered UMS customers will still exist, and so derived profile data will be necessary".*

4.99 The Working Group agreed to restate Clause 42A. The Working Group agreed to clarify the reference to modified version in this response prior to issuing the legal text to the legal advisor.

4.100 The consultant respondent highlighted that P519 – the row with unmetered tariffs should have the 8&0 not on the row below and questioned whether the PC column is relevant any more.

4.101 The Working Group agreed to remove the PC column

Question 6: It is proposed that DCP 268 be implemented on the 01 April 2019. Do you agree with this approach?

4.102 10 respondents agreed with the implementation date of the 01 April 2019. 1 DNO respondent did not agree with the implementation date and provided their reasons in their response to question 8, 9 and 10. The Working Group address the respondent's comments at these questions.

Question 7: Do you have any comments on the updated model or impact analysis? Please provide supporting comments.

4.103 5 respondents had no comment on the impact analysis. Some of these responses are set out below:

- *"There is likely to be significant variation within customer groups, but the analysis does seem to indicate a significant impact for HV medium customers".*
- *"The impacts on the customers move in different directions and are mostly of a very low magnitude with a few outliers. These outliers may need explanation. E.g. LPN and EMEB Domestic Unrestricted".*

- *"The generation group sees a benefit to their tariff as the distinction between intermittent and non-intermittent has been removed. The domestic group sees a small increase due to their contribution to the red time band; however the change to a three rate tariff structure will enable suppliers to offer customers in this group a more transparent time of use tariff. Customers in this group would then be able to respond to the cost signals by reducing their usage in the red time band to reduce their energy costs".*

4.104 The Working Group agreed to consider any outliers and underlying concerns in the change report. This is covered by the Consumer Impact in Section 6 of this Change Declaration.

Question 8: Which DCUSA Charging Objectives does the CP better facilitate? Please provide supporting comments.

Respondent Party Type	Objective 1	Objective 2	Objective 3	Objective 4	Objective 5	No Objectives
DNOs	0	4	5	3	0	1
IDNO	0	0	0	0	0	1
Suppliers	0	1	1	0	0	0
Consultant	0	1	1	0	0	0
Code Administrator	0	1	1	0	0	0
Total	**0**	**7**	**8**	**3**	**0**	**2**

4.105 The majority of respondents agreed that DCUSA Charging Objective 2 and 3 were better facilitated by this change and provided the following rationale:

- *"As the wider use of time band pricing will make DUoS pricing more transparent, which will influence customers to respond to the cost signals providing they are offered by suppliers"*
- *"it simplifies the existing tariff structure".*
- *"As use of the specific DNO time bands more accurately reflect the costs of using the distribution network".*
- *"Aligning the DUOS costs for NHH and HH customers is best for all customers. Using a time band charging methodology will also benefit customers and help DNOs manage the network more effectively".*

4.106 The respondents that considered DCUSA Charging Objective 4 was better facilitated provided the following the rationale:

- *"The introduction of Smart Meters will support the use of HH settlement data".*
- this change sits *"alongside the developments in half hour metering and smart meters"*.

4.107 The Working Group noted that the majority of respondents considered that Charging Objectives 2 and 3 are better facilitated by this CP. Please refer to Section 5 of this report for the Working Group's rationale on which DCUSA Charging Objectives are better facilitated by this change.

4.108 2 Distributor respondents did not consider that any objectives were better facilitated by this change for the following reasons:

- *"as it will place additional costs on both existing and new market entrants".*

  The Working Group considered the costs provided by Parties to this consultation and did not agree that there was a considerable differentiation in costs associated with the distributor approach.

- In regards to objective two, one respondent advised *"we remain unconvinced that this is the case as customers will not be able to respond to pricing signals if they are billed based on profiled data. This does not encourage users to increase their off-peak consumption nor does it encourage them to reduce their peak consumption. Whilst a greater visibility among suppliers (and possibly users) will allow a broader understanding of the time-based charging bands we do not believe that this will benefit consumers or distributors until such time as real consumption data can be used in settlement and billing".*

The Working Group noted that there is the ability of Suppliers to introduce SSCs and time of use tariffs to reduce the consumption in the red timeband when smart meters are in place and still settle in the NHH market.

Question 9: Are you aware of any wider industry developments that may impact upon or be impacted by this CP?

4.109 5 respondents were not aware of any wider industry developments that would impact this CP. The remaining respondents made reference to Ofgem's work on HH settlement and the introduction of smart meters. A representation of those responses is set out below:

- *"Further changes may be required if Ofgem progresses a move to mandatory HHS. The decision is likely to be made in early 2018".*
- *"As mentioned in our first consultant response, the advent of smart meters will revolutionise the methods to track and bill for electricity consumption. Assumed standard consumption patterns (NHH profiles) are expected to be replaced with half hourly metering and settlement. This CP is a*

step we can take now with NHH billing to prepare for this future direction, improve cost reflectivity and make the transition more straightforward, and less of a disturbance to consumers, in the future".

- *"Quote from Ofgem's consultation on HH Settlement, issued 11 November 2016, where they stated in paragraph 4.26";*

  "Work carried out alongside the introduction of P272 introduced new HH metered distribution tariffs [DCP179] These tariffs apply to customers formerly in Profile Classes 1-8, so remain suitable for our work on mandatory HHS."

4.110 The Working Group noted the responses.

Question 10: Are there any alternative solutions or unintended consequences that should be considered by the Working Group?

4.111 9 respondents had no alternative solutions or unintended consequences to raise with the Working Group. 1 DNO respondent reiterated the response they provided to consultation one question ten advising that the change will increase the proportion of DNO revenue recovered from the red time band. Should customers move load away from the red time band due to time of use tariffs, it could lead to significant under recovery of allowed revenue by the DNO and lead to a higher correction factor in future years. This respondent considered that the benefits of the change outweigh this potential issue.

4.112 1 DNO respondent advised that they had *"concerns around the additional workload being placed on billed parties to review and validate DUoS invoices created by either a centralised or distributor approach"*.

4.113 The Working Group noted that Suppliers are already validating de-linked bills and they already do this for Measurement Class G. The Supplier attendees who attended the March 2017 DCP 268 meeting considered that there would be changes to initially set up the billing arrangement but did not see a significant issue from this.

Working Group Conclusions

4.114 The Working Group reviewed each of the responses received to the consultation and concluded that all of the respondents understood the intent of DCP 268.

4.115 The Working Group agreed that the majority of respondents were supportive of the principle of the CP.

4.116 The Working Group noted that the majority of respondents felt that specifically DCUSA General Objectives 2 and 3 were better facilitated by this change.

4.117 Ofgem issued a consultation on 'Half- Hourly (HH) Settlement – The Way Forward' which set out their intention to reform the electricity settlement arrangements to include facilitating Suppliers settling their domestic and smaller non-domestic electricity customers on a HH basis. HH settlement is initially proposed to be on an elective basis with a future expectation that all Suppliers will be mandated to settle their Customers on a HH basis. DCP 268 harmonises the arrangements between NHH and HH on aggregated sites.

Authority Send-Back Letter

4.118 A Change Report was submitted to the DCUSA Panel in May 2017. The DCUSA Panel agreed that the CP should be issued to the voting process. Following the conclusion of the voting process, a Change Declaration was submitted to the Authority on 22 August 2017. Upon review, the Authority referred DCP 268 back to the DCUSA Panel in a letter dated 20 October 2017 noting that the impacts of DCP 268 on charges for embedded generators had not been considered fully; and that the implementation date required further consideration based on Party votes. The Panel subsequently sent this back to the Working Group for further consideration.

4.119 The Working Group reviewed the Authority Decision Letter and noted that a revised Change Report should consider:

- All elements of the proposal, including the removal of the distinction between intermittent and non-intermittent generation, when assessing the impact on the relevant charging objectives; and
- What potential alternative implementation date may be appropriate, taking into account the different time-related concerns expressed by voting parties.

In undertaking these additional steps, the Working Group has also considered how the modification proposal relates to wider work being progressed in this area, such as the Charging Futures Forum (CFF) Access and Forward-Looking Charges Task Forces (TFs).

4.120 In reviewing the distinction between intermittent and non-intermittent generation it was noted that the impact analysis previously undertaken aggregated the intermittent and non-intermittent generators and assumed that the 'average' intermittent generator acts in the same way as the 'average' non-intermittent generator; which is not in line with DNO expectations. Whilst this has no direct impact on the proposed solution for the change itself, the Working Group agreed to refine the impact analysis in order to be more reflective of the expected behaviour of generators in each group and so more closely reflect the charges which would have been implemented had DCP 268 been in place for 2018/19 charges.

4.121 In order to understand the impact on intermittent and non-intermittent generators, it was agreed that a RFI would be issued to DNOs requesting the proportion of units generated in each of the three timebands for intermittent generators connected at Low Voltage, Low Voltage Substation and High Voltage, in order to determine a revised set of illustrative RAG usage values for a typical generator on each tariff. The result of this RFI and the updated impact assessment can be found in the consultation three documentation pack (Attachment 10) and within the impact assessment section 6 below.

DCP 268 Consultation Three

4.122 A consultation was undertaken to seek views on the revised impact assessment and the areas identified by the Authority. There were 11 responses received to consultation three. Three were Suppliers, six were Distributors, one was an IDNO, and one was a consultant. The Working Group discussed each response and its comments are summarised alongside the collated consultation three responses in Attachment 10.

Q1: Do you agree with the Working Group's use of actual RAG sage values calculated from settlement data for intermittent generation in preference to the average of intermittent and non-intermittent values? Please provide your rationale

4.123 Nine respondents supported the use of the actual intermittent data in preference to the average of intermittent and non-intermittent values indicating that it would provide a more accurate view of the impact, whilst two did not.

4.124 One respondent stated that this has no impact on the change itself, as it only affects the impact assessment. Consequently, in their view, anyone who does not agree with this does not necessarily disagree with the intent of, the principle behind, or the solution to the change, but merely with the logic by which the impact assessment presented in the consultation has been compiled.

4.125 Of the two respondents who didn't support this approach, the first cited no benefit to the DCUSA objectives and the second indicated that where there is no actual volume data against the LV Sub Generation Intermittent tariff (as was the case in their area) the RAG split is zero. This tariff is used as a proxy customer group for both the 'LV Sub Generation NHH' and 'LV Sub Generation Intermittent no RP charge' tariffs. This therefore creates a problem where there is volume data against either of these two tariffs.

4.126 The Working Group acknowledged the support for the approach taken in determining the impact assessment. It noted the support in principle from one respondent who highlighted a concern over the lack of data on one tariff resulting in no impact assessment being calculated on another tariff, but this didn't impact the change itself, just the impact assessment for one tariff.

Q2: Do you agree with the Working Group's use of intermittent generation RAG values for NHH generation and no reactive power

charge intermittent generation tariffs in preference to the average of intermittent and non-intermittent values? Please provide your rationale.

4.127 Nine respondents supported the approach to use the proxy values for these tariffs and two did not, with those not supportive quoting the same rationale to that of the first question.

4.128 The Working Group dealt with this concern in its response to question 1. An updated impact assessment is provided in section 6.

Q3: Are the charging objectives better facilitated for generation customers, giving due regard to the removal of the distinction between intermittent and non-intermittent generation? Please provide your rationale

4.129 Eight respondents believed that the DCUSA Charging Objectives were better facilitated; one suggested further analysis was necessary; and two respondents believed that the objectives were not better facilitated.

4.130 Amongst those who believed that the objectives are better facilitated, in the main there was support for objectives 2, 3, 4 and 6 citing that the current flat rate distorts competition; the change will result in more cost reflective tariffs; the change will take account of further developments in the distributor's business; and distributors will no longer need to differentiate between different generation technology types when assigning LLFs, improving efficiency in the implementation of the charging methodologies.

4.131 One respondent suggested further analysis was required especially on technology type noting that it seems reasonably likely that solar generation will be benefiting from the higher payments, by exporting during the red and amber time bands during the spring/summer/autumn months. This would be a concern since solar will not be operational at winter peak, when the real benefit of generation to the network is likely to accrue.

4.132 Two respondents believed that the objectives were not better facilitated. The first believes that the change is immaterial. The second stated that the consumption data will remain based on the same profiled data that is used today. As a result, this will not allow charges to Suppliers and IDNOs to reflect actual consumption in each time band. Where smart meters have been installed, the tariffs introduced as a result of a previous change, alongside the new Measurement Classes (MC) 'F' and 'G', would already deliver the benefits for which this change purports to deliver without the indirect additional cost.

4.133 The Working Group discussed a respondent's concern over the benefit that solar would receive from this change when compared with wind power.

4.134 The concern was whether this would provide the wrong incentive for economic development of the DNO network, rather than whether the RAG approach was more beneficial than the status quo. This was countered by suggestions that in some instances e.g. London where system peak is in the summer, this would be beneficial.

4.135 The Working Group agreed that although it is recognised that the relative benefits for solar and wind are a concern, the methodology being associated with Generation is the same as the methodology for Demand and thus the treatment is one and the same. This could be resolved by a Seasonal Time of Day tariff; however, this is outside of the scope of DCP 268.

4.136 The Working Group noted the rest of the responses and provide their position on the charging objectives in section 5 below.

Q4: Do you agree with the Working Group that the implementation date should be the 1st April 2020? If not please provide your rationale.

4.137 There were six respondents in favour of the implementation date being 01 April 2020 and five against. Those in favour stated that an early decision by DCUSA & Ofgem may give parties 18 to 21 months' notice of the changes and that this should be considered in the context of reform being assessed as part of the Charging Futures agenda and the Targeted Charging Review (TCR) Significant Code Review (SCR), from which Ofgem may direct initiatives to be implemented in 2020/21, potentially undermining the 15 months' notice period DNOs are required to provide in doing so.

4.138 Those against cited that the implementation date is likely to be no different to the lead time of the first change report resulting in one of the reasons for the change being sent back, the additional costs and significant planning requirements this change would introduce, and that it may be better to align the implementation with the plan for mandating HH settlements.

4.139 The Working Group noted the responses and have provided their position on the implementation date in section 7 below.

Q5: Does this CP impact the wider work being progressed in this area, such as the Charging Futures Forum Access and Forward-Looking Charges Task Forces?

4.140 There were mixed views in response to this question. A number of respondents didn't believe there was an impact. Others felt that it had a positive contribution whereas some felt that the CFF TFs were too early in their development stage to determine the interaction. One respondent felt that this change should be tied into the implementation of the HH settlement programme and another that there is a potentially significant impact as a result of the work currently being discussed by the TFs. Changes from this work could alter not only how access to the networks is allocated and paid for, but also in the tariff structures.

4.141 The Working Group noted the mixed responses but concluded that this change proposal should progress independently since the TFs are in the early development phases and the implementation date of the SCR on mandating HH settlements decision is late 2019.

Working Group Conclusions

4.142 The Working Group conclusions to the two key areas identified by the Authority associated with generation charging objectives and the implementation date are discussed further within section 7 and 8 below.

5 Relevant Objectives

Assessment Against the DCUSA Objectives

5.1 For a DCUSA Change Proposal to be approved it must be demonstrated that it better meets the DCUSA Objectives. There are six DCUSA Charging Objectives. The full list of objectives is documented in the CP form provided as Attachment 3.

Initial Change Report

5.2 The Working Group initially considered that the DCUSA Charging Objectives 2, 3 and 4 were better facilitated by DCP 268 although Charging Objective 1 was negatively impacted. However, when considered together there was a unanimous view that the DCUSA Charging Objectives were better facilitated by the change proposal. The reasoning against each objective was set out in the table below:

Impact of the Change Proposal on the Relevant Charging Objectives:	
Relevant Objective	**Identified impacts and rationale**
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	**Negative** • It will place additional costs on Distributors who are not currently de-linked.
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	**Positive** • This change allows greater flexibility in the supply industry to offer time of use tariffs. The development by suppliers of innovative tariffs

electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)	will facilitate competition in electricity supply. • The provision of appropriate cost signals to encourage efficient use of the distribution system subject to the appropriate metering being installed; and • It reduces the number of tariffs from 33 to 16 and provides long term simplification in the calculation of the tariffs
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** • Where appropriate metering is in place, the costs of using the network will not be smeared, but based upon each Suppliers portfolio of customers; and • Where appropriate metering is in place, use of the specific DNO time bands more accurately reflect the costs of using the distribution network
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	**Positive** • this change sits "alongside the developments in half hour metering and smart meters
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.	**None**
Charging Objective Six - that compliance with the Charging Methodologies promotes efficiency in its own implementation and administration.	**None**

Post Authority Send-Back Letter

5.3 The majority of the Working Group now considers that for both demand and generation the DCUSA Charging Objectives 2, 3 and 4 are better facilitated by DCP 268, it does not impact Charging Objectives 1 and 5, and Charging Objective 6 is considered neutral in the round.

5.4 A minority of the Working Group considers a potential negative impact against DCUSA Charging Objective 1 based on Distribution Licence Condition 21.4A[14], whereas one Working Group Member feels that this is offset by the benefits of aligning cost signals for intermittent and non-intermittent generation. The majority of the Working Group therefore believe that there is no impact on DCUSA Charging Objective 1.

5.5 The reasoning against each objective is set out in the table below:

Impact of the Change Proposal on the Relevant Charging Objectives:	
Relevant Objective	**Identified impacts and rationale**
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	**None**
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** • This change allows greater flexibility in the supply industry to offer time of use tariffs. The development by suppliers of innovative tariffs will facilitate competition in electricity supply. • The provision of appropriate cost signals to encourage efficient use of the distribution system subject to the appropriate metering being installed (Demand and Generation); and • The current flat rate tariff for intermittent generation under-values generation technologies which are (perhaps fortuitously) active at peak and consequently overvalues generation technologies which are (by their nature) not active at peak, and hence distorts competition between different intermittent technology types. (Generation)
Charging Objective Three - that compliance by	**Positive**

[14] *"The third requirement is that the Distribution Code, so far as is consistent with the first two requirements, must be designed so as to better facilitate the achievement of the Applicable Distribution Code Objectives, which are to:*

(a) permit the development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity"

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	• Where appropriate metering is in place, the costs of using the network will not be smeared, but based upon each Suppliers portfolio of customers (Demand and Generation); • Where appropriate metering is in place, use of the specific DNO time bands more accurately reflect the costs of using the distribution network (Demand and Generation); and • The removal of the intermittent/non-intermittent distinction will result in more cost reflective tariffs (Generation).
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	**Positive** • this change sits "alongside the developments in half hour metering and smart meters (Demand and Generation)
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.	**None**
Charging Objective Six - that compliance with the Charging Methodologies promotes efficiency in its own implementation and administration.	**Overall Neutral** **Negative Impact** • It will place additional costs on Distributors who are not currently de-linked. (Demand and Generation) **Positive Impact** • It reduces the number of tariffs from 33 to 16 and provides long term simplification in the calculation of the tariffs. (Demand and Generation)

6 Impacts & Other Considerations

6.1 This change impacts IDNOs, DNOs and Suppliers as it transitions all existing NHH DUoS tariffs on to the Red Amber Green (RAG) or Black, Yellow and Green (BYG) arrangement.

Consumer Impacts

6.2 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 (See Consultation two, Attachment 6). DNO Working Group members successfully populated the DCP 268 CDCM model and replicated the expected resulting outputs from this modified model. A template was developed to aid Parties in determining the impact of this change which has been updated for each Distribution area against 2018/19 tariffs.

6.3 This summary workbook displayed the impact on all DNOs and a zip file contained workbooks for each DNO. It used the volume forecast (from 2018/19 published models) for each customer group, and split the units across the RAG time bands as accurately as possible using other CDCM inputs. An annual charge per customer on the basis of the published volume forecast with published tariffs was calculated.

6.4 Parties were invited to comment on the impact of the DCP 268 solution incorporated in to the CDCM model under question 7 of consultation two.

6.5 In the All DNO Impact Assessment excel spreadsheet, there is a customer impact and group impact tab. The group impact tab provides an overview of the portfolio customer showing a reduction for domestic customers of 0.02% and a maximum increase of 2.60%. The non-domestic aggregated customer shows an increase of 2.77% and a maximum reduction of 0.52%.

6.5.1 The distinction between the intermittent and non-intermittent generation is removed. The distinction is no longer required as the DUoS charges will be on a RAG basis regardless of whether the generation is intermittent or non-intermittent. This provides a simplification to the generation tariffs and removes the existing unnecessary complication of allocating different generation across the two tariffs. As a result, the generation group charges have reduced.

6.5.2 Generation – Reactive Power. A separate tariff without reactive power is identical to the other generation tariffs albeit without the reactive charge element.

6.5.3 Domestic - The domestic customer group sees a small increase due to their contribution to the red time band; however, the change to a RAG tariff structure will enable suppliers to offer customers in this group a more transparent time of use tariff if they so choose. The Supplier can identify the changed usage either through HH metering or through appropriate SSC/TPRs reflecting the different DUoS time bands.

6.5.4 Customers in this group would then be able to respond to the cost signals by moving their usage in the red time band into the amber or green time bands reducing their energy costs

6.6 HV Medium customers – the number of these customers is low and they are currently paying considerably less in DUoS charges than an equivalent HV Site Specific tariff. This DCP eliminates this anomaly by ensuring that the tariffs are equivalent and cost reflective. Therefore, the relatively few HV medium customers being migrated onto HV Site Specific tariffs are expected to see an increase in DUoS charges. The numbers of HV Medium customers is expected to have reduced by April 2019 as all the customers will have HH metering and should migrate to HV site specific charging in April 2017. If there are any HV Medium customers remaining at 31 March 2019 then Distributors and Suppliers will need to determine the most appropriate new tariff to apply, the default arrangements for domestic tariff might apply but would result in artificially low charges

6.7 As referred to above, there are some larger than average increases (or decreases) in a small number tariffs in selected regions which is largely as a result of scaling in the methodology. Positive scaling (where the methodology increases the initial yardstick charges to recover the allowed revenue of the DNO) will see an increase in the unit charge, whereas negative scaling (where the initial yardstick charges are reduced) will see a decrease in the unit charge and in more extreme cases can see the removal of the amber and green unit rates, as can be seen in one DNO region. However, this is not a factor solely of DCP268 and is simply more noticed as a result of the RAG (or BYG) approaches being introduced for all tariffs. No party expressed a significant concern with the changes to tariff rates as a result of this change.

Post Authority Send-Back Letter

6.8 The revised impact assessment compares that of the first (referred to under paragraph 6.5 above) with the revised RAG values for intermittent generators i.e. the same impact assessment has been undertaken but with these values replacing those in the 'generator split' tab of the model for each DNO (Attachment 10).

6.9 The outcome is that there is no difference between the two when considering domestic customers and non-domestic aggregated customers (see paragraph 6.5 above).

6.10 However, when considering the impact on embedded generators, the data in initial Change Report shows an increase in credits of between 1.42% through to 36.78%. The revised approach being suggested by the Working Group shows an increase in credits of between 1.14% through to 18.42%.

Environmental Impacts

6.11 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 268 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

6.12 Ofgem has been fully engaged throughout the development of DCP 268 as an observer on the Working Group.

7 Implementation

Initial Change Report

7.1 The proposed implementation date for DCP 268 was the 01 April 2019.

Post Authority Send-Back Letter

7.2 The Working Group considered the responses received during the consultation period and noted that there were two proposed implementation dates: 01 April 2020 and 01 April 2021. The respondents who supported 01 April 2020 suggested their reasoning for this was that parties are likely to get the maximum lead time via this process rather than deferring to the Charging Futures agenda which may result in changes being within the 15-month notice period. Also, the SCR on mandating HH settlement implementation programme is some way off in the future and trying to tie the two together may result in further delays.

7.3 The respondents who supported 01 April 2021 suggested that this would be required due to IT system changes, whereas other respondents cited the impact this would have on customer contracts, and the potential stranding of costs depending on the outcome of the mandating of Half-Hourly Settlements. A further respondent suggested that it would seem logical to merge the DCP 268 and mandatory Half-Hourly Settlements implementation dates.

7.4 The Working Group decided by a slender majority to propose an implementation date for DCP 268 of **1 April 2020**. The Working Group acknowledged that some Parties may not be able to achieve this date, however these Parties would be able to apply for a derogation.

8 Legal Text

8.1 The DCP 268 legal text has been reviewed by the DCUSA Legal Advisor and acts as Attachment 2.

<u>Legal Text</u>

8.2 The legal text changes are red-lines in Schedule 16 Common Distribution Charging Methodology (CDCM) and have been reviewed by the DCUSA modelling consultant. The CDCM has been updated to transition all existing NHH DUoS tariffs on to the RAG (or BYG) arrangement. The Working Group would like to highlight the following changes to the legal text:

- The removing of all NHH arrangements. Under Paragraph 74 the NHH tariffs have been removed from the table containing the standing charge factors for demand tariffs. Under paragraph 137 table 4 showing the demand tariff structures for NHH tariffs has been removed and table 5 displaying the HH demand tariff structures has been updated to include the LV Network Domestic tariff. Tariff structures for LDNOs captured in Table 8 under paragraph 143 have also been updated to remove the NHH tariffs.
- All generation (i.e. intermittent and non-intermittent) is proposed to be treated in the same way under this CP. Under paragraph 142 table 6 containing the NHH generation tariffs has been removed and table 7 containing the HH metered generation tariffs has been updated to remove the intermittent generation tariffs.

8.3 The Working Group have change marked the DCP 268 proposed legal text against the DCUSA charging methodology pre-release text which contains the approved CPs for the 01 April 2018. These CPs are DCP 161 *'Excess Capacity Charges'*; DCP 222 *'Non billing of Excess Reactive Power charges'*; DCP 228 *'Revenue Matching in the CDCM'*; DCP 234 *'Merging the PCDM and extended PCDM'* and DCP 273 *'Align CDCM table 1001 (target revenue) to latest Schedule 15 template'.*

8.4 The CDCM model is also amended to reflect the changes made to Schedule 16, In addition, there are consequential changes to Schedule 17 and Schedule18 due to the EDCM models being changed to reflect the new tariff names. Also, the Annual Review Pack will be updated to reflect the tariff names changes and there are minor changes to the Schedule 19 and Schedule 21 to refer to either 'site specific' or 'aggregated' in preference to 'NHH' or 'HH' where appropriate.

8.5 The Working Group agreed that the legal text meets the intent of this change.

Post Authority Send-Back Letter

8.6 The Working Group reviewed the DCP 268 Legal Text in light of the implementation of DCP 293[15] on 01 April 2018 and made the necessary amendments due to these now being contained within the current version of DCUSA.

9 Code Specific Matters

9.1 There is no specific matter identified.

[15] DCP 293 'Charging Methodology Cut-off Date'

10 Voting

10.1 The DCP 268 Change Report was issued to DCUSA Parties for voting on 20 April 2018.

Part 1 Matter: Authority Decision Required

DCP 268: Proposed Variation (Solution)

10.2 For the majority of the Parties that were eligible to vote, the sum of the Weighted Votes of the Groups in that Party Category which voted to accept the proposed variation was more than 50%.

10.3 DCUSA Parties' have voted and recommend to the Authority to determine that the proposed variation (solution) is accepted for DCP 268.

DCP 268: Implementation Date

10.4 For the majority of the Parties that were eligible to vote, the sum of the Weighted Votes of the Groups in that Party Category which voted to accept the implementation date was more than 50%.

10.5 DCUSA Parties' have voted and recommend to the Authority to determine that the implementation date is accepted for DCP 268.

The table below sets out the outcome of the votes that were received in respect of the DCP 268 Change Report that was issued on 20 April 2018 for a period of 15 working days.

DCP 268	WEIGHTED VOTING				
	DNO	IDNO	SUPPLIER	DISTRIBUTED GENERATOR	GAS SUPPLIER
CHANGE SOLUTION	Accept	Reject	Accept	n/a	n/a
IMPLEMENTATION DATE	Accept	Reject	Accept	n/a	n/a

11 Recommendations

DCUSA Parties Recommendation

11.1 DCUSA Parties have voted on DCP 268 and in accordance with Clause 13.5 of the DCUSA, recommend to the Authority to determine that the Change Proposal be accepted and thus that the proposed variation to the DCUSA should be made.

12 Attachments

- Attachment 1 – DCP 268 Consolidated Party Votes
- Attachment 2 – DCP 268 Legal Text
- Attachment 3 – DCP 268 Change Proposal
- Attachment 4 – DCP 268 Consultation One Documents
- Attachment 5 – DCP 268 Request for Information Documents
- Attachment 6 – DCP 268 Consultation Two Documents
- Attachment 7 – DCP 268 Modelling Documentation
- Attachment 8 – Tariff Mapping Tables
- Attachment 9 – Customer Impact Assessment (Change Report 1)
- Attachment 10 – DCP 268 Consultation Three (including updated Customer Impact Assessment Documentation for Change Report 2)