DCUSA

Part A: Generic

DCUSA Change Proposal (DCP)	At what stage is this document in the process?
	01 – Change Proposal
	02 – Consultation
	03 – Change Report
	04 – Change Declaration

DCP 326:

Introduction of Load Diversification Identifiers for Load Managed Areas

Date Raised: 20 June 2018

Proposer Name: Steven Gough

Company Name: SSEN

Party Category: DNO

Purpose of Change Proposal:

This Change Proposal seeks to introduce a simplified process for retaining the diversification of demand in Load Managed Areas (LMA) during the replacement of RTS controlled metering equipment by Suppliers or post the decommissioning of the Radio Teleswitch System (RTS).

Governance: DCP 326 is raised following the implementation of DCP 204[1] which made changes to Schedule 8 of DCUSA and recommended in the Change Report that further development was needed on the area of demand diversification arrangements. Two DCUSA Issue Forms (DIF) were raised (DIF 45[2] and DIF 50[3]) by the DCP 204 Working Group and have been discussed by the SIG, with a Sub-group being formed for more detailed discussion on DIF 50. The DIF 50 Sub-group have assisted in developing this Change Proposal.

The Proposer recommends that this Change Proposal should be:

- Treated as a Part 1 Matter;
- Treated as a Standard Change; and
- Proceed to a Working Group

The Panel will consider the proposer's recommendation and determine the appropriate route.

Impacted Parties: Suppliers, DNOs, IDNOs

Impacted Clauses: Schedule 8

[1] DCP 204 – 'Smart Metering Related Amendments to Schedule 8'
[2] DIF45 - Replicating Time Switching And Load Switching In The Smart Roll-out;
[3] DIF50 - RTS Management in SMETS2

Contents

Indicative Timeline

The Secretariat recommends the following timetable:

Initial Assessment Report	11 July 2018
Consultation Issued to Industry Participants	TBC
Change Report Approved by Panel	19 September 2018
Change Report issued for Voting	21 September 2018
Party Voting Closes	12 October 2018
Change Declaration Issued to Authority	16 October 2018
Authority Decision	20 November 2018

Any questions?

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1 Summary

What?

We intend to modify the wording to Schedule 8 in the DCUSA to provide to a more practical way of ensuring load diversification in LMAs and introduce a process to facilitate this.

Why?

Currently LMAs have diversification through the use of the Radio Teleswitch Service which ensures that switched demands, such as night storage heaters and water heating, are not all switched simultaneously. To maintain the best value for money for the customer, it is important to retain this load diversification particularly on networks that were designed to use this forward-looking system. If it is not retained the estimated cost in the Scottish Hydro Electric Power Distribution (SHEPD) Licence area alone is estimates in the region of £718m, derived from an EA Technology Ltd (EATL) report[4] written 2012. Making the most efficient use of networks, through diversification of high loads (such as night storage heating) is well aligned with the abilities that's are being developed as part of the transition to Distribution System Operator.

The future of the RTS is uncertain with the current operating contract between the ENA and BBC coming to the end of its term in March 2020 and the steady roll out of smart meters displacing current RTS meters. Currently there is no defined process to retain the diversification that is obligated in Schedule 8. Since this diversification will be required indefinitely, this Change Proposal endeavours to make Schedule 8 easier to comply with and ensures that it is more sustainable into the future.

How?

The proposed solution seeks to make small amendments to Schedule 8 to provide improved flexibility to DCUSA parties who will be responsible for implementing the requirements of Schedule 8. The proposed legal text modification is attached.

The principle proposal is to introduce a Load Diversification Identifier (LDI) which is derived from the last digit of the MPAN at the relevant property. Each LDI will correspond to a specific set of switching times defined by the DNO/IDNO responsible for the connection to the property. This will allow new supply tariffs to have multiple switching times which will retain the required load diversification i.e. any one tariff could have up to ten variants on switching times, one for each LDI. Current tariffs will have their SSCs matched to the new LDIs. By comparison with the current system, use of the LDI to determine switching times for a customer on any tariff will be easier because the LDI is based on readily available information (the MPAN), whereas the information currently required to replicate existing switching times is not held on any central system.

[4] EATL (2012) A Study of the Benefits of the Radio Teleswitch System and the Consequences of Replacement in the SHEPD Licence Area

2 Governance

Justification for Part 1 and Part 2 Matter

This Change Proposal should be classed as a Part 1 matter since it:

- 9.4.1 it is likely to have a significant impact on the interests of electricity consumers;
- 9.4.2 (C) it is likely to have a significant impact on competition in the supply of electricity; and
- 9.4.4 it is directly related to the safety or security of the Distribution Network

Requested Next Steps

This Change Proposal should:

- Proceed to a Working Group

The current RTS operating contract between the ENA and BBC is due to end in March 2020 and the roll out of variant smart meters to replace existing RTS metering equipment is likely to commence towards the end of 2018. These issues will start to erode the current network loading diversity that has been delivered by the RTS system since the 1990's. It is therefore important that this Change is implemented either before the end of 2018 or soon after.

3 Why Change?

In conventional metering the time switch settings on metering systems are implemented on site by the MOP (as the Supplier's agent) via the equipment fitted to reflect the supply tariff (the settings being based on the SSC/TPRs provided by the Supplier). Time switching settings on smart metering systems can be applied remotely or locally (via hand-held terminal equipment).

Only energy suppliers have access to the relevant commands to set the time switching settings on a smart meter. Distributors will have no ability to control, or be involved, with the tariff arrangements applied to any meters on their network. This will lead to a removal of the diversification of switching times in their areas that they were previously able to manage through Group Codes that were randomly associated with the Radio Teleswitch (RTS) infrastructure. For example, there are five published Standard Settlement Configurations (SSC) operating in the SHEPD Scottish Mainland Load Managed Areas (LMA) with a different group code association to each. This means approximately a 5th of the portfolio, on these arrangements, switch concurrently thus providing a smoothing of the load in that region to protect the network from peak demand.

The current obligation in DCUSA is for the supplier to replicate the Switching Regime as closely to that already at the premises: "User shall use reasonable endeavours to ensure that the Load Switching Regime, and any other material characteristics of the existing Load Switching Device, are replicated on the new Load Switching Device". Although this process may be possible to follow for RTS equipment to retain the switching times, as the RTS equipment is removed, the smoothing effect enabled by this will be lost because there is no concept of Group Codes under smart metering.

The implications of this are that the protection provided by the Group Codes will be lost resulting in the security of supply being put at risk, leading to the potential of faults, loss of supply and consequentially a significant negative impact on customers in terms of reliability and costs. This would ultimately lead to an escalation of the processes contained within Schedule 8 such as Security Restriction Notices being issued. The risks to supply security are also exacerbated by the loss of visibility of switching regimes once the RTS meter is replaced with a smart meter. It may also result in more LMAs being introduced. This was highlighted in the development of DCP204.

This change proposed to Schedule 8 will enable the responsible DNO to specify the LDI and hence the corresponding switching times for each customer in an LMA in order to protect their network. Moreover, for Suppliers to comply with Schedule 8 as it stands the Suppliers are required to replicate the current switching times, which they typically have little or no visibility of. There is concern that either through choice or ignorance Schedule 8 as it is currently written will not be complied with. This change provides an easily derivable format that allows more flexibility whilst minimising ongoing workload for Suppliers and maintains the integrity of Schedule 8.

Part B: Code Specific Details

4 Solution and Legal Text

Potential Solution

The DIF 50 Subgroup considered a number of options and have developed a potential solution that replicates the benefit of the RTS arrangement apart from the ability to dynamically switch the load.

The first step would be for the distributor to review the current SSCs associated with Radio Teleswitch devices and ensure that such arrangements are available for time switch selection inclusive of each group code being associated with the SSC. For example, in the Scottish mainland as stated above where there are five Group Codes, an SSC for an Economy Seven supply tariff may result in 5 SSCs being created with the seven hour off peak times varying on each SSC to smooth out the load. Once this work has been completed the DNO may need to raise any new SSCs as part of the Elexon MDD process if any of the proposed combinations are currently not available.

The second step is for the distributor to determine how the historic Group Codes are to be allocated to a Metering Point, as the new Load Diversification Identifiers. A solution to this was suggested within DIF 455. It was suggested that the last digit of the MPAN could be associated with a Group Code:

MPAN ending in 1 = LDI A;

[5] Replicating Time Switching And Load Switching In The Smart Roll-out

MPAN ending in 2 = LDI B etc

This could be expanded to associate multiples together:

MPANs ending 1, 3 and 5 = LDI A

MPANs ending 2, 4 and 6 = LDI B etc

depending on the amount of load management required.

This approach is a simple, easy to identify the MPANs in question and provides an interoperable solution across the industry across all parties.

Once the distributor has decided on the mapping of MPANs to a LDI, there would be an obligation on the distributor within DCUSA to notify the supplier of such a combination. The suggested solution to this is for the distributor to send this as part of the LMA notification process which includes the MPAN and post code. The notification would also identify for each MPAN whether a legacy Group Code is applicable and if so which one.

The third step is for the supplier to ensure that they use the SSC with the specific LDI identified in the LMA notification as part of replicating the tariff arrangement when an RTS meter is removed and replaced with any other load switching device. This requirement on suppliers would also be placed into the DCUSA.

The suggested legal text is shown below.

Risks

The project associated with mandating HH settlement (via a Significant Code Review) may remove the need for SSCs in Half-hourly trading. To mitigate this risk, the administrator for the BSC, the Authority and potentially the Department for Business, Energy and Industrial Strategy (BEIS) should be invited to review this suggested solution either in advance of a Change Proposal being raised or for them to form part of the working group developing the solution further once a Change Proposal has been raised.

The proposal does not provide for dynamic load shifting. If this is required as a feature of tariffs by suppliers (in order to ensure continuity of service and that choice is not lost for consumers who currently have dynamic switching tariffs), an alternative means of implementing dynamic switching would need to be developed.

Legal Text

Schedule 8 – Demand Control

Add a new definition

Load Diversification Identifier	An Identifier containing a selection of Load Switching Regimes that are available to a Metering Point in order to smooth the load in a Load Managed Area, thereby protecting the network from peak demand.

5.3 A Load Managed Area Notice shall be effective when received or deemed to be received in accordance with Clause 59 and shall indicate:

(a) the geographical area to which it applies by providing the MPAN, ~~and~~ postcode and where appropriate the Load Diversification Identifier associated with the MPAN (or such other method as the Company and the Supplier agree, acting reasonably);

(b) the time or times of day during which in the Company's opinion:

(i) changes to Load Switching Regimes in force at particular Metering Points introduced by Suppliers have increased the coincidence of Demand to such an extent that Security of Supply may be threatened; and

(ii) new applications of Load Switching Regimes to particular Metering Points introduced by Suppliers may reasonably be expected to increase the coincidence of Demand to such an extent that Security of Supply may be threatened;

(c) the date from which the notice is effective; and

(d) that it shall continue in force until withdrawn in writing by the Company by serving a notice on all Suppliers and the Authority

5.4 The Company and the User acknowledge and agree that the issue of a Load Managed Area Notice constitutes notice that:

(a) significant modifications of Customer Demand in the area identified in such notice may threaten Security of Supply;

(b) SRNs and Emergency SRNs may be issued in respect of that area;

(c) any future changes to Load Switching Regimes and/or the Randomised Offset Limit in force at particular Metering Points in that area may be subject at the request of the Company to change in accordance with Paragraph 7.6 or 8.6; and

(d) any changes to Load Switching Regimes and/or the Randomised Offset Limit referred to in Paragraph 5.4(c) will, if requested by the Company pursuant to Paragraph 7.6 or 8.6 or if made voluntarily by a User, be at the relevant User's cost.

(e) where the User is replacing a Load Switching Device at a particular Metering Point, in the area identified in such a notice, the User shall use reasonable endeavours to ensure that the Load Switching Regime, and any other material characteristics of the existing Load Switching Device, are replicated on the new Load Switching Device (including the use of the Load Switching Regimes associated with a Load Diversification Identifier at a particular Metering Point where these have been issued by the Company in accordance with Paragraph 5.3 (a)); and

(f) where the User is unable to comply with Paragraph 5.4 (e) the User will consult with the Company and agree to alternative arrangements for that particular Metering Point.

7.3 A Security Restriction Notice shall be effective when received or deemed received in accordance with Clause 59 and shall indicate:

(a) the geographical area to which it applies by providing the MPAN and postcode and where appropriate the Load Diversification Identifier associated with the MPAN (or such other method agreed as per Paragraph 5.3(a))

7.4 The Company and the User acknowledge and agree that the issue of a Security Restriction Notice constitutes notice that:

(a) any modifications of Customer Demand induced by changes to Load Switching Regimes in the area identified in such notice may threaten Security of Supply;

(b) Emergency SRNs may be issued in respect of that area and that such notices will normally not be issued within 20 Working Days of the Effective Date of the relevant Security Restriction Notice;

(c) any future changes to Load Switching Regimes and/or the Randomised Offset Limit in force at particular Metering Points in that area may be subject at the request of the Company to change in accordance with Paragraph 7.6 or 8.6; and

(d) any changes to switching times in order to effect changes to Load Switching Regimes and/or the Randomised Offset Limit referred to in Paragraph 7.4(c) will, if requested by the Company pursuant to Paragraph 7.6 or 8.6 or if made voluntarily by a User, be at the relevant User's cost.

8.3 An Emergency SRN shall be effective when received or deemed to be received in accordance with Paragraph 11.3 and shall indicate:

(a) the geographical area to which it applies, by providing the MPAN and postcode and where appropriate the Load Diversification Identifier associated with the MPAN (or such other method agreed as per Paragraph 5.3(a));

8.4 The Company and the User acknowledge and agree that the issue of an Emergency SRN constitutes notice that:

(a) any modifications of Customer Demand induced by changes to Load Switching Regimes in the area identified in that notice may threaten Security of Supply;

(b) any future changes to Load Switching Regimes and/or the Randomised Offset Limit in force at particular Metering Points in that area may be subject to reversion to the Load Switching Regimes for the relevant Metering Points at the Effective Date of the Emergency SRN, or to such other Load Switching Regimes as shall not have a materially adverse effect on Security of Supply;

(c) any changes to switching times in order to effect changes to Load Switching Regimes and/or the Randomised Offset Limit referred to in Paragraph 7.4(b) will, if requested by the Company, be at the relevant User's cost;

(d) where the User is replacing a Load Switching Device at a particular Metering Point, in the area identified in such a notice, the User shall use reasonable endeavours to ensure that the Load Switching Regime, and any other material characteristics of the existing Load Switching Device, are replicated on the new Load Switching Device (including the use of the Load Switching Regimes associated with a Load Diversification Identifier at a particular Metering Point where these have been issued by the Company in accordance with Paragraph 5.3 (a)); and

(e) where the User is unable to comply with Paragraph 8.4 (d) the User will consult with the Company and agree to alternative arrangements for that particular Metering Point

8.5 This Paragraph 8.5 applies where the Company, having issued an Emergency SRN, reasonably believes that Load Switching Regimes and/or the Randomised Offset Limit allocated in respect of the Customers of a User have materially contributed to the risk to Security of Supply in respect of which the Emergency SRN has been issued.

8.6 Where Paragraph 8.5 applies, the Company may also send a Compliance Notice to that User, and a copy to the Authority, which notice shall require the User:

(a) to change at its own cost and within such period of time as the Company considers reasonable the Load Switching Regimes and/or the Randomised Offset Limits in force at particular Metering Points in the area designated in the Emergency SRN to the Load Switching Regimes for the relevant Metering Points at the Effective Date of the relevant Security Restriction Notice (or, where the Company reasonably believes that it is necessary, to such other Load Switching Regimes as shall not have a materially adverse effect on Security of Supply); or

(b) to take such other action as the Company considers reasonable,

(c) provided that where the Company requires changes to Load Switching Regimes and/or the Randomised Offset Limits in an area which is not a Load Managed Area or to Load Switching Regimes and/or the Randomised Offset Limit which have not been modified by the User since the Effective Date of the current Load Managed Area Notice, then the reasonable cost visits required to affect such changes shall be at the Company's cost.

5 Code Specific Matters

Reference Documents

DCP 204 – Smart metering amendments to Schedule 8 – implemented 01 September 2016

DIF 45 – Replicating Time Switching And Load Switching In The Smart Roll-out - withdrawn

DIF 50 - RTS Management in SMETS2

The issue this Change Proposal attempts to remedy was initially raised within DCP 204 and resulted in DIF 45 being raised. This was withdrawn due to the potential overlap with the Balancing and Settlement Code (BSC) CP 1443 'Standard Settlement Configurations (SSCs) for Smart And Advanced Meters'.

DIF 50 was subsequently raised since the BSC change did not consider the issue. The DIF 50 Subgroup was set up under the Standing Issues Group to discuss and develop a solution. The solution and the legal text developed by the Subgroup is shown within section 4 of this Change Proposal.

6 Relevant Objectives

	DCUSA General Objectives	Identified impact
☒	1. The development, maintenance and operation by the DNO Parties and IDNO Parties of efficient, co-ordinated, and economical Distribution Networks	Positive
☒	2. The facilitation of effective competition in the generation and supply of electricity and (so far as is consistent therewith) the promotion of such competition in the sale, distribution and purchase of electricity	Negative
☒	3. The efficient discharge by the DNO Parties and IDNO Parties of obligations imposed upon them in their Distribution Licences	Positive
☒	4. The promotion of efficiency in the implementation and administration of the DCUSA	Positive
☒	5. 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

1. The change will continue to protect the network and avoid substantial reinforcement works. It will also facilitate a more effecitive process to co-ordinate with suppliers.
2. The proposal will limit the exact switching times that can be applied to customers and therefore limit the times in the tariffs that can be offered.
3. DNOs/IDNOs must operate a safe and reliable network, this proposal significantly limits the likehood of overloading which impacts both of these.
4. The change is a minor amendment which simplifies the process of retaining the necessary diverisification during the smart meter roll out and beyond.

7 Impacts & Other Considerations

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

None

Does this Change Proposal Impact Other Codes?

BSC	☐
CUSC	☐
Grid Code	☐
MRA	☐
SEC	☐
Other	☐
None	☒

Consideration of Wider Industry Impacts

The change does limit the precise switching times that a customer can have and it will mean a significant number of customers will need to change from their current switching times. Although the proposer, during the discussions at the SIG sub group, pushed for these switching times to be retained, the forward looking implications of a simpler solution makes this solution easier and more efficient to maintain. The proposal allows for multiple tariffs to be offered for each LDI so the tariff offered to the customer will not be impacted.

Confidentiality

None

8 Implementation

Implementation in February 2019 ahead of significant displacement of RTS meters due to the ongoing roll out of smart meters.

9 Recommendations

Part C: Guidance Notes for Completing the Form

Ref	Section	Guidance
1	**Attachments**	Append any proposed legal text or supporting documentation in order to better support / explain the CP.
2	**Governance**	A CP must be categorised as a Part 1 or Part 2 matter in accordance with Clause 10.4.7 of the DCUSA. All Part 1 matters require Authority Consent. **Part 1 Matter** A change Proposal is considered a Part 1 Matter if it satisfies one or more of the following criteria: a) it is likely to have a significant impact on the interests of electricity consumers; b) it is likely to have a significant impact on competition in one or more of: i) the generation of electricity; ii) the distribution of electricity; iii) the supply of electricity; and iv) any commercial activities connected with the generation, distribution or supply of electricity; c) it is likely to discriminate in its effects between one Party (or class of Parties) and another Party (or class of Parties); i) it is directly related to the safety or security of the Distribution Network; and ii) it concerns the governance or the change control arrangements applying to the DCUSA; and iii) it has been raised by the Authority or a DNO/IDNO Party pursuant to Clause 10.2.5, and/or the Authority has made one or more directions in relation to it in accordance with Clause 11.9A. **Part 2 Matter** A CP is considered a Part 2 Matter if it is proposing to change any actual or potential provisions of the DCUSA which does not satisfy one or more of the criteria set out above.
3	**Related Change Proposals**	Indicate if the CP is related to or impacts any CP already in the DCUSA or other industry change process.
4	**Proposed Solution and Draft Legal Text**	Outline the proposed solution for addressing the stated intent of the CP. The Change Proposal Intent will take precedence in the event of any inconsistency. A DCUSA Working Group may develop alternative solutions. The plain English description of the proposed solution should include the changes or additions to existing DCUSA Clauses (including Clause numbers). Insert proposed legal drafting (change marked against any existing DCUSA drafting) which enacts the intent of the solution. The legal text will be reviewed by the Working Group (if convened) and is likely to be subject to legal review as part of its progress through the DCUSA change process.

5	**Proposed Implementation Date**	The Change can be implemented in February, June, and November of each year or as an extraordinary release. For Charging Methodology CPs, select an implementation date which takes into consideration the minimum notice periods for publishing tariffs. These are: NOs acting within their Distribution Services Areas; or NOs and DNOs acting outside their Distribution Services Area. Please select an implementation date that provides sufficient time for the Change to be incorporated into the appropriate charging model and the DCUSA in order to be reflected in future tariffs. Contact the DCUSA helpdesk for any further information on the releases dcusa@electralink.co.uk.
6	**Impacts & Other Considerations**	Indicate whether this Change Proposal will be impacted by or have an impact upon wider industry developments. If an impact is identified, explain why the benefit of the Change Proposal may outweigh the potential impact and indicate the likely duration of the Change.
7	**Environmental Impact**	Indicate whether it is likely that there would be a material impact on greenhouse gas emissions as a result of the proposed variation being made. Please see Ofgem Guidance.
8	**Confidentiality**	Clearly indicate if any parts of this Change Proposal Form are to remain confidential to DCUSA Panel (and any subsequent DCUSA Working Group) and Ofgem
9	**DCUSA General Objectives**	Indicate which of the DCUSA Objectives will be better facilitated by the Change Proposal.
10	**Detailed Rationale for DCUSA Objectives**	Provide detailed supporting reasons and information (including any initial analysis that supports your views) to demonstrate why the CP will better facilitate each of the DCUSA Objectives identified.
11	**DCUSA Charging Objectives**	Indicate which of the DCUSA Charging Objectives will be better facilitated by the Change Proposal.
12	**Defining 'Material' for Charging Methodology Changes**	In respect of proposals to vary one or more of the Charging Methodologies, such proposals shall be deemed to be "material" if they might reasonably be expected to have a significant impact on the tariffs calculated under one or more of the methodologies.