Data Communications Company

SEC Modification Proposal, SECMP0085, DCC CR1399

Synchronisation of Smart Meter voltage measurement periods

Preliminary Impact Assessment (PIA)

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1 Document History

1.1 Revision History

Revision Date	Revision	Summary of Changes
10/09/2020	0.1	Initial version, for DCC internal review
10/09/2020	0.2	Updated following DCC internal review

1.2 Associated Documents

This document is associated with the following documents:

Ref	Title and Originator's Reference	Source	Issue Date
1	DP085 Problem Statement	SECAS	18/09/2019
2	MP085 Modification Report	SECAS	21/07/2020
3.	MP085-March-Working-Group-Meeting-summary	SECAS	13/03/2020
4.	MP085 Business Requirements	SECAS	21/07/2020

References are shown in this format, [1].

1.3 Document Information

The Proposer for this Modification is Alan Creighton of Northern Powergrid. The proposal was submitted in March 2020.

Following the working group meeting, the Preliminary Impact Assessment (PIA) was requested of DCC on 19th June 2020 with the associated documents including Modification Report and Business Requirements revised in July 2020.

2 Context and Requirements

In this section, the context of the Modification, assumptions, and the requirements are stated.

The SEC Definitions, issue statement, and requirements following have been provided by SECAS and the Proposer.

2.1 Current Arrangements

The RMS voltage value of an Alternating Current (AC) circuit represents an equivalent voltage of a Direct Current (DC) circuit. Electricity Network Parties use Smart Meter average root mean square (RMS) voltage and average consumption data to monitor the performance of distribution networks and identify any problems.

Once there is data available in reasonable quantities from Smart Meters, Electricity Network Parties plan to use this data to develop the most efficient solution to any identified problem. The uptake in Low Carbon Technologies, particularly Electric Vehicles and Distributed Generation, is expected to cause an increase in the number of power flow and voltage issues in distribution networks. Voltage and consumption data from Smart Meters will help manage these issues efficiently in the future.

2.2 What is the issue?

The expectation of Electricity Network Parties during the development of the Smart Meter Equipment Technical Specification (SMETS) was that the average RMS voltage readings from Smart Meters would be measured across a consistent period. For example, with the default being for an average to be made across 30 minutes starting on the hour and on the half-hour as per the half-hour consumption profile data. This is not an explicit requirement codified in the SMETS or in the Great Britain Companion Specification (GBCS).

Whilst some electricity meter Manufacturers' meters work in this way, other Manufacturers' meters do not. Without voltage measurements being made in a consistent way, Electricity Network Parties must either make conservative, less efficient analysis assumptions to account for the lack of data alignment or recreate synchronised data by downloading high granularity (for example minute resolution) data and calculating the required data.

During the Refinement Process, the Smart Energy Code Administrator and Secretariat (SECAS) obtained information from a Network Party relating to meters that do not commence average RMS voltage readings on the hour. Of the meters tested by four Network Parties, over 50% provide average RMS voltage readings later than required.

Average RMS voltage readings that relate to random 30-minute periods are helpful for identifying voltage problems at individual customer premises. However, without synchronised recording times it will be difficult to:

- understand voltage issues on Low Voltage feeders that may be affecting more than one customer;
- identify trends or forecast future voltage issues; or
- validate power flows and voltages on a network model relating to a defined 30-minute period, and hence identify the most efficient solution.

2.3 Impact of the issue

2.3.1 Network Operators

This section contains the impact of the issue on the Network Operator as provided by the Proposer and SECAS. In this context Network Operator means both the Electricity and Gas Network Operators.

There are two headline implications if this issue is not addressed:

- Electricity Network Parties will either need to make conservative assumptions about network voltages which may lead to inefficient solutions being implemented; or
- Electricity Network Parties will need to reconfigure the average RMS voltage measurement period from the default period of 30 minutes to one minute and download the high granularity data so that they can recreate synchronised data in their systems. This will increase the voltage related traffic on the Data Communications Company (DCC) infrastructure by a factor of 30 and require Electricity Network Parties to develop systems to manage a greater volume of data than originally envisaged. This is not considered to be an efficient solution.

The Proposer has stated that the issue lies with the requirements for specifying the timings when the RMS voltage readings take place. Currently, it is not stipulated in the Technical Specifications and there will need to be amendments to Smart Metering Equipment Technical Specifications (SMETS) (Smart Energy Code (SEC) Schedule 9).

3 Description of Solution

After the discussion of this proposal in different fora such as Change Sub-Committee (CSC), Technical Architecture and Business Architecture and Sub-Committee (TABASC), Operations Group (OPSG) and Security Sub-Committee (SSC), following list of business requirements are identified.

Ref	Requirements
1	Electricity Smart Metering Equipment (ESME) to commence calculating the average Root Mean Square (RMS) voltage at 00:00 or 30:00 (whichever occurs first) of the first hour once the ESME has been first energised.
2	ESME to commence calculating the average RMS voltage at 00:00 or 30:00 (whichever occurs first) of the first hour after a command has been received to change the average RMS voltage measurement period.
3	ESME to continue to calculate the average RMS voltage at a frequency in accordance with the average RMS voltage measurement period, until a command is received to change the average RMS voltage measurement period.
4	Average RMS voltage measurement period is to be a maximum duration of 1,800 seconds with alternative periods being factors of 1,800 seconds.
5	ESME to retain any existing entries in the Average RMS Voltage Profile Data Log relating to the period before the ESME was energised or before a command to change the Average RMS Voltage Measurement Period**Error! Reference source not found.** has been received.
6	The MP085 solution shall not cause any changes to the current security access or rights.
7	The MP085 solution shall not cause any changes to the storage or network requirements.
8	The MP085 solution will not modify or create a new GBCS command/message.

The DCC and Service Providers have reviewed all these requirements and expect that changes are required in DSP systems only to meet requirement # 4. The other requirements imply changes in SEC Schedule 9 - Smart Metering Equipment Technical Specifications(SMETS) and possible changes in ESME firmware to apply the changes on installed ESMEs.

The following section details the DCC impact for requirement # 4.

3.1 SEC Changes

For requirement # 4, the DCC and Service Providers have reviewed the solution and expect the changes required in SEC Appendix AD - DCC User Interface Specification (DUIS). Section 3.8.57 of SEC Appendix AD shall get updated to include the additional validation and error code.

The actual change to the SEC Appendix AD for the Service Request Variant (SRV) data validation with the updated DUIS schema of Request will be provided during the Full Impact Assessment (FIA).

3.2 DSP Solution Overview

Electricity Network Operators use the Service Request (SR) 6.5 - Update Device Configuration (Voltage) to set a measurement period in an Electricity Meter. DSP will amend the processing of SR 6.5 to introduce a new validation check to verify the value of the attribute 'Average RMS Voltage Measurement Period'. If the Average RMS Voltage Measurement Period is not a factor of 1800, then the Service Request will be rejected using a specific error code. A new error code will be introduced for this, which will require changes to the DUIS schema.

In situations where the Service Users do not use a version of DUIS that supports the new error code, the existing error code E060501 will instead be used to indicate failure. DUIS Guidance will be required for Service Users to inform them of this possible usage of E060501.

The valid values for Average RMS Voltage Measurement Period will need to be finalised during the Full Impact Assessment (FIA) stage. A Feature Switch will be used to enable the new validation check.

The following assumptions are recorded for the above-mentioned DSP Solution.

i. The new validation check is applicable only for Service Requests targeted at SMETS2+ Devices.

ii. There will be no changes to the corresponding GBCS Use Cases in terms of the structure for the associated changes in SEC Schedule 9 and therefore no changes to the Transform libraries.

Request Management requires a modification to add the new validation check to SR6.5 processing.

3.3 Other Solution Impacts

Apart from DSP, no other DCC Components are impacted by this change.

4 Impact on DCC Systems, Processes and People

This section describes the impact of SECMP0085 on DCC Services and Interfaces that impact Users and/or Parties.

4.1 System Components

Change in Request processing of SR 6.5 requires a change in Request Management components at DSP.

4.2 Security Impact

The implementation will be security assured during the implementation phase. This includes reviewing designs, test artefacts and providing consultancy to the implementation and test teams.

A more detailed security impact will be carried out as part of the Full Impact Assessment.

At this stage, a penetration test and updates to protective monitoring are not thought to be required.

4.3 Technical Specifications

There will be changes in DUIS and corresponding changes in DUGIDS for the changes in DUIS. The DUIS Guidance document also needs to be updated.

No other changes are expected in any Technical Specification for the SRV 6.5 validation changes however SEC Schedule 9 – SMETS specification is expected to be updated for overall requirements.

4.4 Integration Impact

An appropriate level of Systems Integration and User Integration Testing (SIT and UIT) will be carried out prior to progressing the release of this change to the Production environment, but this is not included in the PIA.

4.5 Infrastructure Impact

There will be no change to the infrastructure design as a result of this change.

The Modification does not impact DSP resilience or Disaster Recovery implementation.

4.6 Application Support

No changes to Application Support are expected.

4.7 Service Impact

No material impact is expected for the Operations team and no changes to SLAs are expected.

4.8 Safety Impact

No impact is expected, but a full Safety Impact Assessment will be carried out as part of the production of the FIA.

4.9 Contract Schedules

No changes to contracts are expected, but this will be re-evaluated for the FIA.

5 Implementation Timescales and Approach

As this change affects DUIS Schema, it will need to be implemented as part of a scheduled release. Notwithstanding in which release this change is implemented, based on the current response from the Service Provider, the elapsed time for implementation from project initiation through to PIT completion will be 2 months.

The release lifecycle duration will be confirmed as part of the FIA. As currently planned, the standard ongoing major release model will provide drops to the production environment in November 2021.

5.1 Implementation Approach

Implementation of this change is assumed to follow a hybrid of agile and waterfall methodology. The release lifecycle duration will be confirmed as part of the FIA.

5.2 Testing and Acceptance

It is assumed that the change will be implemented and tested as part of a major release and will include release based regression testing in SIT and UIT.

6 Costs and Charges

The table below details the cost of delivering the changes and Services required to implement this Modification Proposal.

The scope of supply under this PIA includes design, development (build), system testing, and performance testing within the PIT environments.

The Rough Order of Magnitude cost (ROM) shown below describes indicative costs to implement the functional requirements as assumed above. The price is not an offer open to acceptance. It should be noted that the change has not been subject to the same level of analysis that would be performed as part of a Full Impact Assessment and as such there may be elements missing from the solution or the solution may be subject to a material change during discussions with the DCC. As a result, the final offer price may result in a variation.

6.1 Design, Build and Testing Cost Impact

The table below details the cost of delivering the changes and Services required to implement this Modification. For a PIA, only the Design, Build and PIT indicative costs are supplied.

£	Design, Build and PIT
Synchronisation of Smart Meter voltage measurement periods	100,000-200,000

Based on the existing requirements, the total fixed price cost for a Full Impact Assessment by all Service Providers is **£8645.12** and would be expected to be completed in 30 days.

7 Risk, Assumptions, Issues, and Dependencies

In the following sections, Risks, Assumptions, Issues, and Dependencies have been identified. Two clarifications are also requested.

Further RAID may be established as part of the Working Group reviews and the FIA.

7.1 Risks

None at this time.

7.2 Issues

None at this time.

7.3 Dependencies

Ref.	Area	Dependency	Impact
MP085-DD01	IA	To meet all the business requirements defined in Reference[4], changes are required in SEC Schedule 9.	Medium

7.1 Assumptions

Ref.	Area	Assumption	Impact
MP085-AS01	IA	The changes in SEC Schedule 9 will be taken care of by SECAS.	Medium
MP085-AS02	IA	The changes in SEC Schedule 9 will be targeted for SMETS2+ devices only.	Low
MP085-AS03	IA	No changes required to the corresponding GBCS Use Cases in terms of the structure for the associated changes in SEC Schedule 9.	Medium
MP085-AS04	IA	To apply the changes of SEC Schedule 9 on the installed meters, delivery of build and test of ESME Meter Firmware changes will be taken care of by the Device Manufacturers.	Medium

Appendix A: Glossary

The table below provides definitions of the terms used in this document.

.Acronym	Definition
AC	Alternating Current
CR	DCC Change Request
CSC	Change Sub-Committee
DC	Direct Current
DCC	Data Communications Company
DSP	Data Service Provider
DUIS	DCC User Interface Specification
ESME	Electricity Smart Metering Equipment
FIA	Full Impact Assessment
GBCS	Great Britain Companion Specification
OPSG	Operations Group
PIA	Preliminary Impact Assessment
PIT	Pre-Integration Testing
RMS voltage	Root Mean Square voltage
ROM	Rough Order of Magnitude (cost)
SEC	Smart Energy Code
SECAS	Smart Energy Code Administrator and Secretariat
SIT	Systems Integration Testing
SMETS	Smart Metering Equipment Technical Specification
SP	Service Provider
SR	Service Request
SRV	Service Request Variant
SSC	Security Sub-Committee
TABASC	Technical Architecture and Business Architecture and Sub-Committee
UIT	User Integration Testing