RETAIL ENERGY CODE

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01	Proposal Plan
02	Impact Assessment
03	Consultation
04	**Final Recommendation**

CHANGE REPORT

R0216 - REC CHANGES TO TIE IN WITH DCP419

DOCUMENT VERSION	V1.0
PROPOSED IMPLEMENTATION DATE	26 June 2026
IMPLEMENTATION APPROACH	Big Bang

RESPONSIBLE COMMITTEE	Metering Expert Panel	**CHANGE PATH**	Authority Determined
PRIORITY STATUS	Medium	**URGENCY**	Standard
IMPACTED STAKEHOLDERS	DNOs, MOAs, SIPs, EMOs, CMRMs, Revenue Protection Agents, Energy Suppliers		

LEAD ANALYST (SOLUTION LEAD)	SUBJECT MATTER EXPERT
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OVERVIEW

DCP419 is looking to place obligations on any Party or agent to update the Distribution Network Operator (DNO) before any planned De-energisation or communications interruptions on Sites with a Smart Meter. This is to allow DNOs to be able to manage any off-supply notifications (via AD1 alerts).

CODE MANAGER RECOMMENDATION

The Code Manager recommends that the REC Metering Expert Panel recommend that the Authority:

- **REJECT** the proposed change solution;
- **REJECT** the proposed implementation approach; and
- **REJECT** the proposed implementation date of 26 June 2026.

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BACKGROUND

1 SUMMARY

DNOs have an obligation to contact Consumers when they receive a Power Outage Event Alert (AD1) to ensure the Consumer is not experiencing a power outage. This obligation is in the Ofgem Reporting Instructions and Guidance (RIG) Annex F and is as below:

- Ofgem RIIO-ED2 Regulatory Instructions and Guidance – Interruptions 2.12 Single premises power outage alerts originating from a smart meter are not reasonably expected to indicate no supply. Where an outage alert is received, the DNO should contact the customer as soon as reasonably practicable thereafter to check whether the customer is without power, but only between 8am and 9pm.

RIGs are documents associated with the Electricity Distribution Licence. The DNOs are required to comply with them as if they were part of the licence. This is specified in Condition 46 of the Electricity Distribution Standard Licence Conditions.

While this alert is generated whenever a Smart Meter experiences a power outage, it is also generated when a Smart Meter is De-energised for planned works or when the Communications Hub is disconnected in order to be replaced. This means that DNOs may be contacting Consumers unnecessarily, for work the Consumer and other industry Parties were aware of in advance. This issue is expected to increase as the 2G to 4G Communications Hub replacement project commences in 2025, likely increasing the number of AD1s generated.

A change has been raised under the Distribution Connection and Use of System Agreement (DCUSA) as DCP419 Pre-Notifications of Planned Supply De-Energisations, of which R0216 is a cross-code change to.

These changes propose that all Parties who attend Sites to work on Smart Meters, or their Communications Hubs, must notify the DNO of this work in advance, and that DNOs do not have an obligation to contact these Consumers where such a notification is received.

2 PROBLEM STATEMENT

DNOs may be unnecessarily contacting Consumers where an AD1 notification is generated but the Consumer is having planned works involving their Electricity Smart Meter or Communications Hub replacements for their Electricity Smart Meter. This may create a poor Consumer experience.

3 IMPACTS

CONSUMERS
Electricity Consumers with Smart Meters

REC DOCUMENTS / PRODUCTS
Schedule 14 – Metering Operations
Data Specification

REC PARTIES AND SERVICE USERS
DNOs
MOAs
EMOs

SIPs
CMRMs
Revenue Protection Agents
Communications Hub replacement agents

Communications Hub replacement agent is not a defined term under the REC. The Code Manager is using it in this instance to mean any agent that replaces only the Communications Hub on a Smart Meter, as there is no requirement for that agent to be a Consolidated Metering Code of Practice (CoMCoP) registered Party.

MHHS
There is an indirect impact to the MHHS Code Drafting as this Change Proposal expects to make changes to Schedule 14 – Metering Operations. The Code Manager will be mindful of this when drafting the proposed legal text.

4 CROSS-CODE IMPACTS

This is a cross-code change with DCUSA change DCP419 Pre-Notifications of Planned Supply De-Energisations.

On 28 May 2025, the Cross Code Steering Group (CCSG) confirmed REC as the lead Code for these changes.

5 PROPOSAL PLAN

Milestone	Activity	From	To
Definition		**05-Nov-24**	**31-Jul-25**
	Code Manager Assessment	November	November
	Solution Development	November	February
	Impact Assessment	February	March
	Solution Refinement	March	July
	Business Case Assessment	March	July
Change Proposal		**01-Aug-25**	**09-Sep-25**
	Consultation	August	August
	Solution Refinement	August	September
	Final Determination	September	September
Voting		**10-Sep-25**	**10-Sep-25**
	Issue for Authority Determination	11-Sep-25	11-Sep-25

The definition solution refinement period included legal review from the REC Legal Counsel.

6 STAKEHOLDER ENGAGEMENT

DCP419 has been progressing under a DCUSA working group since 27 April 2023. There have been 15 work group meetings, two consultations and one Request For Information between that time and 03 February 2025.

The original scope of DCP419 was a requirement on Safe Isolation Providers (SIPs) only to provide this pre-notification to DNOs but has been expanded under the DCUSA working group.

I0216 was discussed at the REC Change Issues Group on 07 November 2024, with the minutes available on the REC Portal.

7 PRIORITY STATUS AND URGENCY

PRIORITISATION MATRIX

Category	Significance / Resource impacts / Urgency	Further selection / breakdown	Score (0-3)	Weighting	Weighted Score
Impacts	Consumer Impact	Direct	2	27	53
	Retail Markets Impact	Innovation and Market Arrangements	2	17	33
	RECCo / REC Party / REC Service Provider Impact	Operational Effectiveness and Efficiencies	3	7	20
		Legal and Regulatory Compliance	1	14	14
Resource	Complexity / Effort / Duration		1	9	9
Strategic Alignment	Contribution to/ Alignment with the objectives of the REC		1	17	8
	Contribution to/ Alignment with RECCo's Forward Work Plan		0		0
Urgency *(The need to progress a change to meet a targeted date)*		Other Planned Activity	0	10	0
				Overall Priority Score (rounded)	138

Priority Status	MEDIUM
Change Proposal Type	STANDARD

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SOLUTION

8 PROPOSED SOLUTION

The solution proposes a new Market Message to be sent over the Data Transfer Network and was initially developed by the DCP419 Working Group. It was further developed under the REC when the scope of the Change Proposal and the legal text that would be required to implement it became clear.

This market message would be sent by the below list of Parties to the DNO the day before any planned works:

- Metering Operator Agent (MOA) / Metering Service;
- Safe Isolation Provider (SIP);
- Crowded Meter Room MOA (CMRM); and
- Electricity Supplier.

It was originally proposed that the Market Message would be sent to the Electricity Supplier as well, but feedback was received at Party impact assessment this was not necessary. It was also proposed there would be a DNO to DNO Scenario Variant, which has also been removed following feedback at Party impact assessment.

The structure of the proposed Market Message is as below:

MMXXXXX - Notification of planned supply de-energisations

Market Message Reference	**MMXXXXX**
MM Description	This data flow is to be utilised by all relevant Parties that de-energises or otherwise interacts with the Communications of a Whole Current Metering Point with a Smart Meter installed, as part of any planned work, provide the Distribution Network Operator with advance notification of the supply interruption.
Local Catalogue Reference	D0XXX
Version	001
Notes	

Scenario Variants

Scenario Variant	Name	Source	Target	Owner
SV00XXX	Notification of planned supply de-energisations	Electricity Supplier	Distribution Network Operator	REC
SV00XXX	Notification of planned supply de-energisations	Meter Operator Agent	Distribution Network Operator	REC
SV00XXX	Notification of planned supply de-energisations	Safe Isolation Provider	Distribution Network Operator	REC
SV00XXX	Notification of planned supply de-energisations	Crowded Meter Room MOA	Distribution Network Operator	REC

SV00XXX	Notification of planned supply de-energisations	Smart Metering Service	Distribution Network Operator	REC
SV00XXX	Notification of planned supply de-energisations	Advanced Metering Service	Distribution Network Operator	REC

Data Items:

Data Item Number	Reference	Name
DI50003	J0003	MPAN Core
DI50008	J0012	Additional Information
DI51342	J2050	Customer Agreed Appointment Date

Flow Structure:

Group ID	Group Description	Range	Condition	L1	L2	L3	L4	L5	L6	L7	L8	Data Item Name	Data Item Rule
AAA	MPAN Cores	1-*		G									
					1							MPAN Core	
BBB	Customer Agreed Appointment Details	0-1			G								
						1						Customer Agreed Appointment Date	
						O						Additional Information	

Since Party impact assessment, the proposed owner of the Scenario Variants have been updated from the DCUSA to the REC as all the proposed legal text for this Change Proposal sits within the REC and all Data Items within the Market Message are owned by the REC. This advice was provided by the REC Technical Services team and by CCSG, to prevent the need for complex, cross code changes in the future.

There are also updates required to Schedule 14 - Metering Operations, requiring that Parties send this Market Message to DNOs. These are documented in section 9 of this report.

The proposed solution does not include any requirements for Performance Assurance monitoring. Following discussions with the Performance Assurance team and RECCo, it has been decided that if approved, it is likely most appropriate that this solution would be audited by the Metering Scheme Auditor. As the Code Manager minded to position is to recommend rejection for this Change Proposal, the Code Manager and RECCo have agreed not to include Performance Assurance requirements as part of this Change Proposal but will commit to raising a future Change Proposal for the consideration of those if R0216 is approved by the Authority. Service Provider impact assessment with the Metering Scheme Auditor will be conducted under that Change Proposal.

9 DRAFT LEGAL TEXT

The legal text changes to deliver the proposed solution to R0216 can be found here.

The Code Manager has drafted the legal text changes in the MHHS version of Schedule 14 - Metering Operations. The solution proposes the insertion of clauses:

- Section 2 General Obligations, Electricity Suppliers Only – where the Electricity Supplier is aware of a planned site visit on an Electricity Smart Meter which will De-energise the Meter (including Meter Exchanges and Removals), or remove or change the Communications Hub, they must send the Notification of planned supply De-energisations Market Message to the DNO at least one Working Day before the site visit. This is not applicable for site visits booked on the same day as the appointment;
- Section 2 General Obligations, Electricity MOAs Only – where the MOA is aware of a planned site visit on an Electricity Smart Meter which will De-energise the Meter (including Meter Exchanges and Removals) or remove or change the Communications Hub, they must send the Notification of planned supply De-energisations Market Message to the DNO at least one Working Day before the site visit. This is not applicable for site visits booked on the same day as the appointment;
- Sections 28 and 43 Safe Isolation Providers – where the SIP is aware of a planned site visit on an Electricity Smart Meter which will De-energise the Meter (including Meter Exchanges and Removals) or remove or change the Communications Hub, they must send the Notification of planned supply De-energisations Market Message to the DNO at least one Working Day before the site visit. This is not applicable for site visits booked on the same day as the appointment; and
- Sections 29 and 44 Crowded Meter Room MOAs – where the CMRM is aware of a planned site visit on an Electricity Smart Meter which will De-energise the Meter (including Meter Exchanges and Removals) or remove or change the Communications Hub, they must send the Notification of planned supply de-energisations Market Message to the DNO at least one Working Day before the site visit. This is not applicable for site visits booked on the same day as the appointment.

10 DESCOPED SOLUTIONS

10.1 APPLICATION/API NOTIFICATIONS

The Code Manager explored a second solution at Party impact assessment, involving the introduction of an online application and/or API to send notifications. This would have allowed the same list of Parties as above to notify the DNO of planned site visit but could also have included Revenue Protection and/or Debt Collection Agents and Communication Hub replacement agents. These Parties are not required to send Market Messages, so are out of scope of the DTN message.

This has been descoped due to a lack of support from industry Parties. While many Energy Suppliers and MEMs were supportive of this solution over the Market Message solution, it was made clear that they would prefer neither be implemented. Several Energy Suppliers and MEMs asked for the discounted Smart Energy Code (SEC) solution to be re-investigated (see section 10.2 below).

10.2 SMART ENERGY CODE

There was also a proposed solution looked at under the SEC, to amend the requirements on the Data Communications Company (DCC) to only send the AD1 notification in certain circumstances – for example, if a power outage was registered but was not restored within one hour.

This was discussed at the DCUSA Working Group 14 held on 26 November 2024 (minutes available here), where the Energy Networks Association (ENA) presented they had held a meeting with the DCC. ENA confirmed that the DNOs would not accept using the power outage restoration alert as a mechanism to not contact Consumers, as this is typically received 30 minutes after the power outage alert and that DNOs had agreed they would contact Consumers within 15 minutes of receiving the power outage alert. This position was confirmed by both Northern Powergrid and Scottish and Southern Electricity Networks.

There was also a discussion around the DCC creating a bespoke solution for DNOs under the SEC. This was discounted due to the cost and timescales involved with this solution, with no further details provided. The REC Code Manager has since engaged with the SEC who have confirmed they had no detail on cost or timescale to provide without a full impact assessment being completed by the DCC, but did note that DCC changes are often costly and lengthy.

Several Energy Suppliers and MEMs asked for this solution option to be investigated again at Party impact assessment. The Code Manager made the decision not to pursue this, as they believe there is alternate solution with a more suitable business case. This is detailed further in section 13.3 of this report. Any Party can raise a change to the SEC if they wish this to be explored further.

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PRELIMINARY ASSESSMENT

11 SUMMARY OF IMPACT ASSESSMENT ACTIVITY

11.1 SERVICE PROVIDER IMPACT ASSESSMENTS

No Service Provider impact assessment was required as part of this Change Proposal.

11.2 REC PARTY IMPACT ASSESSMENTS

A Party impact assessment was conducted from 27 February to 21 March 2025. A total of 19 responses were received from seven Energy Suppliers, five Metering Equipment Managers (MEMs), six DNOs and the Crowded Meter Room Co-ordinator. Two of these responses were submitted confidentially, and one anonymously. The public responses have been published here.

ENERGY SUPPLIERS	• Of the Energy Suppliers who responded, two provided no preference, four preferred the API solution and one preferred the Market Message solution if they had to pick between the two options. However, almost all Energy Suppliers wanted neither of these solutions pursued with three requesting the discounted SEC solution be relooked at. • Six Energy Suppliers confirmed they saw no benefits to their business from the implementation of either the Market Message or API solution, and that any expected benefits would be seen only by DNOs. • Of Energy Suppliers who confirmed expected costs, these ranged between £10,000 and over £100,000 for both the Market Message solution and API solution, other than one who estimated no cost for API solution. Of these Energy Suppliers, most estimated the API solution would cost less to implement than the Market Message solution. • Of Energy Suppliers who confirmed the lead time they would require, one said they would require six months after MHHS has been implemented for either solution option. One confirmed a lead time of six months for the Market Message solution, and significantly shorter for the API solution. Another confirmed 12 to 18 months for either solution option. • The only risk called out by Energy Suppliers for MHHS is having to utilise the same resource for two large system changes around the same time.
DISTRIBUTION NETWORK OPERATORS	• Four DNOs preferred the Market Message solution, one preferred the API solution and one saw benefit in both being implemented – the Market Message short term and the API long term. • The DNOs who preferred the Market Message solution raised concerns around the API including time to develop and potential

	costs. In particular, DNOs raised that the API solution would be more expensive for them than the Market Message solution. • DNOs felt this solution appropriately accounted for the industry move to MHHS, although some queried whether a DIP flow could be used rather than a DTN flow. • DNOs confirmed no to minimal risks to their MHHS implementation from this Change Proposal, assuming that it would be implemented after MHHS go-live. • Of DNOs who confirmed the lead time they would require, this ranged from seven days to nine months for the Market Message solution. No specific timescales were provided for the API solution, other than significantly longer than the Market Message solution. • Of DNOs who confirmed their estimated costs, this ranged from £0 to £50,000 for the Market Message solution and £10,000 to £100,000 for the API solution.
METERING EQUIPMENT MANAGERS	• Of the MEMs who responded, four preferred the API solution and none preferred the Market Message solution if they had to pick between the two options. However, half of MEMs wanted neither of these solutions pursued and requested the discounted SEC solution be relooked at. • One MEM suggested that there be no obligation on the MOA to send the Market Message and it should only be on Energy Suppliers. The Code Manager has discounted this option as to cover situations where the Consumer has a direct contract in place with the MOA, or any other scenarios where the MOA books or amends an appointment directly with the Consumer. • All MEMs confirmed they saw no benefits to their business from the implementation of either the Market Message or API solution, and that any expected benefits would be seen only by DNOs. • Of MEMs who confirmed expected costs, these ranged between £50,000 and £100,000 for both the Market Message solution and API solution. Of these MEMs, most estimated the API solution would cost less to implement than the Market Message solution. • Of MEMs who confirmed the lead time they would require, three said they would require minimum six months lead time to implement either solution. • The main risk called out by MEMs for MHHS is having to utilise the same resource for two such large system changes around the same time.
CROWDED METER ROOM CO-ORDINATOR	• Alt Han Co responded as the Crowded Meter Room Co-ordinator (CMRC). They expressed no preference between the Market Message or API solution options, but did confirm one of

	their Crowded Meter Room MOAs (CMRMs) preferred the API solution option. • They did not confirm any required lead time or costs associated with this Change Proposal.

12 RISKS, ASSUMPTIONS, ISSUES AND DEPENDENCIES

12.1 RISKS AND ISSUES

There are no risks or issues associated with this Change Proposal.

12.2 ASSUMPTIONS AND DEPENDENCIES

NO.	ASSUMPTION	NOTES	HOW/WHEN TO VALIDATE
R0216.A01	The number of AD1 notifications received by DNOs is expected to increase as the 2G to 4G Communications Hub replacement rollout occurs.	The Code Manager notes that the definition of AD1 notifications under the SEC specifies that they are generated when a power outage to the Communications Hub lasts three minutes or longer. The SEC have confirmed it takes longer than three minutes to install a new Communications Hub, so it is expected Communications Hub replacements will generate AD1 alerts.	Not possible to validate, but the Code Manager considers this a reasonable assumption.

NO.	DEPENDENCY	NOTES	STATUS
R0216.D01	The Ofgem RIGs may need updating to be in line with the REC and DCUSA.	The Code Manager notes that the Ofgem RIGs may need updating to ensure it and the Codes are not in conflict. This is not known for certain, but if it is required then it may not be possible outside of the	Open – to be determined by the Authority as part of their decision.

		normal annual RIG update process. If this is not required, it does not change the Code Managers assessment (as laid out in section 13.3 of this report) that amending the RIGs has a better business case than the implementation of this Change Proposal.	
R0216.D02	If R0216 is approved, a further Change Proposal will be raised by the Code Manager to consider Performance Assurance requirements.		Open – dependent on Authority approval.

13 BUSINESS CASE ASSESSMENT

13.1 COSTS

There are no central systems costs associated with this Change Proposal, as any Performance Assurance requirements have been descoped to a future Change Proposal if R0216 is approved by the Authority. However, there will likely be additional costs from the Metering Scheme Auditor for the addition of this to their audit – based on previous Change Proposals that have impacted the Metering Scheme Auditor (REC Changes R0064 and R0152), the Code Manager estimates these costs will be under £20,000.

At Party impact assessment, the following costs were identified by Parties for the implementation of the Market Message solution and new obligations:

- MEMs ranged between £50,000 and £100,000 per respondent;
- DNOs ranged between £0 and £50,000 per respondent; and
- Energy Suppliers ranged between £10,000 and £100,000 per respondent.

These are based on the Parties who provided figures/a range of expected costs. Many further Parties said they expected costs but could not provide an estimate.

Based on the REC Party Register showing a total of 17 Qualified MOAs, 40 DNOs and 111 Acceded Electricity Suppliers, the Code Manager estimates a minimum industry cost of £1.9 million and a maximum of £14.8 million. This maximum assumes all Energy Suppliers and MOAs offer Smart Metering which the Code Manager is aware is not the case, so costs are not expected to be as high as the maximum stated here.

The Code Manager would also like to highlight the below intangible costs.

INTANGIBLE COSTS	COSTS DESCRIPTION
COMMUNICATIONS HUB REPLACEMENT AGENTS ARE NOT IN SCOPE	Part of the concern raised by DNOs has been the expected increase in AD1 notifications they expect to receive from the 2G to 4G Communications Hub replacement rollout. The Code Manager agrees this is likely to occur but is aware that many Energy Suppliers do not plan on booking appointments in advance of these replacements. As these agents will not be required to send Market Messages and there will be many replacements where the Energy Supplier is not aware of the date in advance and so also cannot send the Market Message, this will not help the DNOs manage the expected increase AD1 volumes.
SAME DAY APPOINTMENTS ARE NOT IN SCOPE	As the solution is a Market Message and must be sent at least the day before the planned appointment is due to occur, same day appointments are out of scope of this solution. Data provided to the Code Manager from some Parties at impact assessment indicated same day appointments make up between 5% and 35% of a Parties monthly site visits. There is potential for this to be transitioned to a Data Integration Platform (DIP) interface in the future which could allow for same day appointments to be moved in scope, but the Code Manager has not explored this option at this time while MHHS migration and transition are underway.
CONSUMER POWER OUTAGES WHEN A PLANNED APPOINTMENT IN CANCELLED	There is no proposed requirement for any Party to send up a follow up Market message to the DNO to tell them if a planned site visit has been cancelled or changed dates. This means that if the DNO received the Market Message, the job was then cancelled or moved and the Consumer had a genuine power outage on the day the appointment was originally booked for, they would not be contacted the DNO.

13.2 BENEFITS

At Party impact assessment, the average number of AD1s received per month by DNOs was provided across 12 regions. These ranged between 2,747 and 124,347 per month, with an average of 46,872 per month.

The average cost of DNOs contacting a Consumer was provided by six regions, which ranged between £0.03 and roughly £5 per contact.

Using these figures, the Code Manager estimates between £16,000 and £2.8 million is spent per region annually contacting Consumers when an AD1 is received. This large range is due to some DNOs having a more automated process involving text messages, while some are using call centre staff to phone Consumers.

Five Energy Suppliers and MEMs confirmed at Party impact assessment their average number of planned jobs where the Site has a Smart Meter which was required to be de-energised or had a Communications Hub replacement ranged between 300 to 83,000 per month, with an average of 28,000 per month.

Using this average to calculate roughly 336,000 of these jobs per year where DNOs would no longer be required to contact these Consumers, the Code Manager estimates DNO regions would save between £9,000 and £1.6 million annually.

The Code Manager would also like to highlight the below intangible benefits.

INTANGIBLE BENEFITS	BENEFITS DESCRIPTION
IMPROVED CONSUMER JOURNEY	Consumers would no longer be contacted unnecessarily during planned works within scope of the R0216 solution, leading to an improved Consumer experience. This has only been discussed anecdotally with no data available to the Code Manager to attempt to quantify this benefit.
REDUCTION IN REPUTATIONAL DAMAGE TO INDUSTRY	The implementation of this Change Proposal would lead to a reduction in reputational damage seen by the energy industry. A consultation response highlighted this as a benefit, as not implementing this Change Proposal shows Consumers the potential lack of communication between Parties and, for DNOs that are contacting Consumers, wasted resources on outages that haven't occurred. This has only been discussed anecdotally with no data available to the Code Manager to attempt to quantify this benefit.
AWARENESS OF PLANNED WORKS FOR DNOS	The implementation of this Change Proposal would provide DNOs with a greater awareness of works happening in their area. One DNO who spoke with the Code Manager confirmed they saw this as a benefit from the implementation of this Change Proposal.

13.3 COST BENEFIT ANALYSIS

There are multiple costs and benefits associated with this Change Proposal.

The estimated savings available to DNOs are significant, but the Code Manager is aware that not all DNOs are contacting Consumers when a power outage alert is received (confirmed by one DNO in their Party impact assessment response). As such, we expect the costs and savings to be on the lower end of the estimates as there are some DNOs where their costs (and so expected savings) are £0. However, the Code Manager cannot state this with confidence as the ranges are so large.

This Change Proposal also highlights there are likely cost savings available to DNOs without a Code change, as the range of DNOs cost to serve is so large (£0.03 and roughly £5 per contact).

The savings benefit would be seen solely by DNOs, whereas the costs are spread between Energy Suppliers, MEMs and DNOs – with Energy Suppliers and MEMs expecting higher costs than DNOs, and no benefits to their organisations.

The REC is a Consumer facing Code and Consumer benefits are at the heart of many of our Change Proposals. However, the Consumer benefit in this case of a reduction in the number of unnecessary contacts received from a DNO is low compared to the cost of implementing this Change Proposal.

The Code Manager also notes that while ENA and some DNOs confirmed they aim to contact Consumers within 15 minutes of receiving a power outage alert, this is not a requirement in the Ofgem RIG which confers this obligation:

- Ofgem RIIO-ED2 Regulatory Instructions and Guidance – Interruptions 2.12 Single premises power outage alerts originating from a smart meter are not reasonably expected to indicate no supply. Where an outage alert is received, the DNO should contact the customer as soon as reasonably practicable thereafter to check whether the customer is without power, but only between 8am and 9pm.

As such, the Code Manager is of the opinion the RIG could be amended to provide more clarity on the DNO obligation. For example, this could state that the DNO should contact the customer as soon as reasonably practicable where a power outage alert is received, and a power outage restoration alert is not received within 30 minutes, where the customer is not on Priority Services Register.

This would come at no cost to any industry Party as the RIGs go through an annual consultation, review and update process. This process typically runs from January to March, with the new RIGs being applicable from April, so the earliest this could be implemented would be April 2026.

Many Parties indicated at impact assessment they required six months between approval and implementation as is normal for any Market Message related Change Proposal, so the Code Manager would be proposing implementation of R0216 as part of the February 2026 standard REC Release (assuming Authority Decision is received by August 2025) at the earliest. As such, the Code Manager believes there is not a large enough difference in implementation timescales between this Code change and amending the RIGs to be seen as a detriment. Between this and the no costs to Parties, the Code Manager believes amending the RIGs is a viable alternate solution with a better business case than R0216.

14 CASE FOR CHANGE

The Code Manager does not believe that R0216 better facilitates the following REC Objectives:

OBJECTIVE	IMPACT TYPE	DESCRIPTION AND JUSTIFICATION
To ensure the REC operates and evolves in a manner that facilitates the achievement of its mission statement[1]	Neutral	The REC mission statement is to facilitate the efficient and effective running of the retail energy market, including its systems and processes through promoting innovation, competition, and delivering positive customer outcomes.

[1] REC Mission Statement

		The Code Manager believes that R0216 has a neutral impact on this REC objective. It will increase efficiency and lead to improvements for DNOs, in them not having to contact Consumers with pre-planned site visits on Electricity Smart Meters. It will however decrease efficiency for MOAs, CMRMs, SIPs and Energy Suppliers as it will add an extra step into the process when booking appointments for these scenarios. As the majority of the costs estimated are to be seen by Energy Suppliers and MEMs, whereas the majority of the savings and benefits are expected to be seen by DNOs the cost-benefits are not equally proportionate amongst Parties. The Code Manager does not believe that the costs or benefits outweigh the other, and so the impact to the REC and industry overall is neutral.
To ensure customers interests and data is protected in the operation of the REC	Neutral	The Code Manager believes R0216 has a neutral impact on this REC objective. It will potentially lead to an improved Consumer experience for some Consumers with Electricity Smart Meters who have pre-planned site visits to not receive unnecessary contact from the DNO. However, it will not do so for all Consumers in this scenario. For example, it will not reduce the potential need to contact Consumers while the 2G to 4G Communications Hub replacement rollout occurs. It will also not do so for Consumers who have a same day appointment booked in. Data provided to the Code Manager from some Parties at impact assessment indicated same day appointments make up between 5% and 35% of a Parties monthly site visits. This Change Proposal does not touch on the Consumers interest or data, only their experience. Based on this and the above, the Code Manager considers there to be neutral impact on this objective.
To drive continuous improvements and efficiencies in the operation of the REC and the central systems and communication infrastructures it governs	Neutral	The Code Manager believes R0216 has a neutral impact on this REC objective. It will increase efficiency and lead to improvements for DNOs, in them not having to contact some Consumers with pre-planned site visits on Electricity Smart Meters. It will however decrease efficiency for MOAs, CMRMs, SIPs and Energy Suppliers as it will add an extra step into the process when booking in appointments for these scenarios. The solution does not allow for real time updates, requiring MOAs, CMRMs, SIPs and Energy Suppliers to send the

		Market Message the night before the planned visit. This means that any same day appointments will be out of scope of the R0216 solution. Data provided to the Code Manager from some Parties at impact assessment indicated same day appointments make up between 5% and 35% of a Parties monthly site visits. The Code Manager believes the alternate solution of amending the Ofgem RIGs to provide more clarity on DNO obligations around contacting Consumers would lead to greater efficiency than the implementation of R0216. The example provided by the Code Manager in section 13.3 of this report would still lead to greater efficiency for DNOs (only contacting Consumers if a power outage restoration alert is not received within 30 minutes) and not require any extra steps to be added to MOA, CMRM, SIP or Energy Supplier processes. It may also lead to greater efficiencies for DNOs than the implementation of R0216 as Communications Hub replacements where an appointment is not booked in advance would still be able to be included.

15 SUMMARY OF CONSULTATION RESPONSES

A consultation was circulated on 11 July 2025 to obtain views on the Change Report (For Consultation). In total 14 responses were received from six Energy Suppliers, three Metering Equipment Managers, four Distribution Network Operators and the Crowded Meter Room Co-ordinator. Two of these responses were submitted confidentially and one anonymously.

The key themes from these responses have been summarised and set out below. The non-confidential responses have been published here.

15.1 SUMMARY OF RESPONSES

Energy Suppliers and MEMs believe this Change Proposal should not be implemented whereas DNOs believe this Change Proposal should be implemented.

15.2 COMMENTS ON THE SOLUTION AND PROPOSED LEGAL TEXT

There were limited comments on the legal text to support the proposed solution.

Some Energy Suppliers and MEMs highlighted they preferred the descoped API solution over the Market Message solution which has been taken forward. However, most comments at Party impact assessment from Energy Suppliers/MEMs that preferred the API solution came with a heavy caveat they preferred neither solution, and did not support this Change Proposal at all. They only preferred the API solution if one had to be implemented. DNOs overwhelming did not want the API solution.

The Code Manager felt there was not enough support for a solution that would have involved a lengthy tender and Service Provider impact assessment process to get ROM costs, to then recommend rejection.

One respondent queried if it was possible to simplify the proposed Market Message further and remove the Additional Information Data Item. The Code Manager has considered this and made the decision to leave it in as part of the proposed solution, as it is an optional field and not required to be populated.

Some Energy Supplier and MEM respondents have highlighted they believe this Change Proposal may not help DNOs manage this RIG obligation as there is no obligation within the REC legal text for them to use the Market Message. The Code Manager has reviewed this but concluded we cannot mandate DNOs use the Market Message in this way, as it is not a REC obligation it would help manage.

15.3 BENEFITS RELATIVE TO IMPLEMENTATION AND OPERATIONAL COSTS

The majority of respondents agreed with the costs and benefits as laid out by the Code Manager.

Many respondents noted the large range in both costs and benefits calculated. The Code Manager acknowledges this but is the most accurate that could be calculated using the information provided at Party impact assessment.

A DNO respondent highlighted the reduction in reputational damage as a further benefit of this Change Proposal, which the Code Manager has added to section 13.2 of this Change Report.

15.4 CHANGE PATH AND CODE MANAGER'S RECOMMENDATION

All 14 respondents agreed with the proposed Change Path of Authority Determined, following a recommendation by the REC Metering Expert Panel.

All Energy Supplier and MEM respondents agreed with the Code Manager recommendation that this Change Proposal be rejected. All DNO respondents disagreed and believed this Change Proposal should be implemented – although one did caveat this with a comment that they agreed that same day appointments not being in scope of the solution does reduce the expected benefits from the implementation of this Change Proposal.

The CMRC did not provide an opinion on whether this Change Proposal should be approved or rejected.

15.5 IMPLEMENTATION DATE AND APPROACH

13 of 14 respondents agreed with the implementation approach of Big Bang if this Change Proposal were approved for implementation. The one respondent who did not agree submitted their response confidentially, but it has been considered by the Code Manager.

Six respondents agreed with the proposed implementation date of 26 February 2026. Two agreed with 26 February 2026 as long as this provided six months between approval and

implementation, which the Code Manager believes is unlikely when the Change Proposal is subject to approval by the Authority.

Six respondents disagreed with the proposed implementation date of 26 February 2026, citing June 2026 release or six months being required between approval and implementation and noting the time required for an Authority decision. Two respondents believed this Change Proposal should not be implemented before MHHS migration is completed.

Based on this feedback, the Code Manager has amended the proposed implementation date to be 26 June 2026.

16 SUMMARY OF AMENDMENTS MADE FOLLOWING CONSULTATION

The following amendments have been made following the consultation.

- The Code Manager has removed the text from the Market Message flow notes, as this was a duplicate of the description.
- The proposed implementation date has been updated to 26 June 2026.
- A correction has been made to section 11.2 REC Party impact assessments to reflect that one Energy Supplier stated the implementation of this Change Proposal would cost more than £100,000. This has not changed the costs in section 13 Business Case Assessment which uses £100,000 as the upper limit for calculations.
- A new intangible benefit has been added, as highlighted by a Party consultation response. This is the reduction in reputational damage to the industry, with more details available in section 13.2 of this Change Report.

No changes have been made to the proposed legal text in Schedule 14 – Metering Operators following the consultation.

RETAIL ENERGY CODE

17 APPENDIX

CHANGE PROPOSAL	Link
LEGAL DRAFTING	Link
CONSOLIDATED IMPACT ASSESSMENT RESPONSES	Link
CONSOLIDATED CONSULTATION RESPONSES	Link
RELATED CHANGE(S)	DCUSA DCP419

18 GLOSSARY

TERM	DEFINITION
Communications Hub	means a physical device that includes a Communications Hub Function together with a Gas Proxy Function. As defined under the Smart Energy Code.
Crowded Meter Room MOA (CMRM)	means a Qualified MOA that has been contracted to perform that role by the Crowded Meter Room Coordinator.
Distribution Connection and Use of System Agreement (DCUSA)	means the agreement of that name maintained pursuant to the Electricity Distribution Licences.
Distribution Network Operator (DNO)	means a person holding an Electricity Distribution Licence.
Electricity Metering Operative (EMO)	means a Party which is approved (or which is seeking approval) as such under the Metering Accreditation Schedule, being an entity which undertakes the installation, replacement, repair and maintenance of electricity Metering Equipment.
Meter Operator Agent (MOA)	means a Party which has Qualified in that role under the Qualification and Maintenance Schedule. Where used in respect of a particular Metering Point, it means the MOA Appointed by an Electricity Supplier in accordance with the Metering Operations Schedule. The MOA is accountable for the installation, replacement, repair and maintenance of electricity Metering Equipment (either itself or by an EMO), and the MOA must also therefore be Accredited under the Metering Accreditation Schedule.

Power Outage Event Alert (AD1)	As defined under the Smart Energy Code - Communications Service Provider (CSP) notification of loss of DC power as detected at the Communications Hub in the Consumer Premises for a time equal to or greater than three (3) minutes.
Revenue Protection Agent (RPA)	means, for each Energy Supplier or Network Party, an internal or external provider of services related to Energy Theft.
Regulatory Instructions and Guidance (RIGs)	The main reporting mechanism for RIIO-ED2 which provide a common framework for DNOs to report relevant performance data, cost, and financial information to Ofgem. The RIGs specify the information required and provide guidance on how to provide this information
Revenue = Incentives + Innovation + Outputs (RIIO)	The RIIO-ED2 price control sets the outputs that the 14 electricity distribution network operators (DNOs) need to deliver for their consumers and the associated revenues they are allowed to collect. RIIO-ED2 covers a five-year period from 1 April 2023 to 31 March 2028. Ofgem monitor and evaluate the DNOs' performance over RIIO-ED2. The main reporting mechanism is the regulatory instructions and guidance (RIGs).