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NON-CONFIDENTIAL CONSOLIDATED IMPACT ASSESSMENT RESPONSES

I0216 REC CHANGES TO TIE IN WITH DCP419

On 27 February 2025 the Code Manager issued an impact assessment to industry to seek feedback on the proposed solution for I0216 REC Changes to tie in with DCP419.

The purpose of this document is to consolidate the responses and for the Code Manager to answer any questions raised within those responses.

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RESPONSE TYPE	NON-CONFIDENTIAL
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RESPONSIBLE COMMITTEE	Metering Expert Panel
LEAD ANALYST	Caroline Freimuller

DATE IMPACT ASSESSMENT ISSUED	27 February 2025
RESPONSE DEADLINE	21 March 2025

Question 1:	Did you attend the DCUSA Work Group for DCP419?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	Yes	Thank you for confirming.
E.ON Energy Services (Metering Equipment Manager)	Yes the one held on 3rd February	Thank you for confirming.
Scottish and Southern Electricity Networks (Distribution Network Operator)	Yes, SSEN are the sponsor of the working group. Nikhel Jethwa originally raised this change, but left SSEN in August 2024, where Jordan Hills took over.	Thank you for confirming.
Northern Powergrid (Distribution Network Operator)	Yes. Warren Lacey is an active member of the workgroup	Thank you for confirming.
Scottish Power (Energy Supplier)	Yes	Thank you for confirming.
Alt HAN Co (Crowded Meter Room Co-ordinator)	Yes, Alt HAN Co has been attended all the work group meetings.	Thank you for confirming.
National Grid Electricity Distribution (Distribution Network Operator)	Yes	Thank you for confirming.
OVO (Energy Supplier)	OVO did attend.	Thank you for confirming.

Anonymous Metering Equipment Manager	Yes, attended workgroup 15 on 3rd February. I would suggest that workgroups 1 to 14 should also have been open to MEMs, given that this is a significant change for us.	Thank you for confirming. The REC Code Manager's understanding is that MEMs are able to attend all DCUSA Work Groups in a non-voting role. We will pass this feedback onto DCUSA to look at improving how they engage with all Parties impacted by their Code. I0216 was raised once DCP419 was flagged at the Cross Code Steering Group (CCSG). This recognised the REC impacts and allowed REC to signpost DCP419 to MEMs and other interested participants.
SSE Energy Supply (Energy Supplier)	Yes.	Thank you for confirming.
Calisen Metering Services (Metering Equipment Manager)	No.	Thank you for confirming.
ENGIE (Energy Supplier)	No, but we did respond to the DCUSA consultation on DCP 419.	Thank you for confirming.
Electricity North West (Distribution Network Operator)	No.	Thank you for confirming.
UK Power Networks (Distribution Network Operator)	n/a	n/a
IMServ (Metering Equipment Manager)	Attended one meeting on 03/02/2025 however have tracked minutes from all previous.	Thank you for confirming.

Scottish Power Energy Networks (Distribution Network Operator)	No.	Thank you for confirming.
British Gas (Energy Supplier)	Yes.	Thank you for confirming.

Question 2:	Do you have any comments on the proposed solutions, including any preference between solution option 1 or 2?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	Overall, we are yet to see a clear and concise benefits case for implementing anything for pre notification. As a supplier, there is no benefit to us sending any pre notification to the DNO's. This change has been bought in to essentially help DNO's meet an obligation that does not impact anyone else within the industry. Whilst there is a concern about customers being contacted unnecessarily, it has been noted that DNO's are currently not doing this and have also not wanted to engage with Ofgem to fully understand how they can meet these obligations without impacting customers. Option 1 will be costly to suppliers but not to DNO's who are the only people that would benefit from having the flow sent. Option 2 is our preferred option but does still come without a potential cost and inconvenience to implement. Option 2 allows freedoms when it comes to the future 4G rollout and means that suppliers can make ad hoc and spontaneous decisions on installations without having to ensure pre notification is sent via a flow.	Thank you for your comments.
E.ON Energy Services (Metering Equipment Manager)	Solution option 2 would be our preference but with an API and an app. Our Field team would continue to use our app but this would be enhanced to send the API call as part of our standard process. Other	Thank you for your comments.

	teams could use the app as this will be needed less often. This would be the most flexible option.	
Scottish and Southern Electricity Networks (Distribution Network Operator)	Solution 1 makes use of the current industry standard communications tool between all DCUSA parties, the Data Transfer Network. SSEN believe this would be fairly cost effective to deliver on and would also be faster to implement when compared to Solution 2. Solution 2 suggests the creation of a new application/webapp to report on the planned de-energisation of metering equipment. The only apparent benefit from delivering this solution as opposed to delivering Solution 1 is a quicker notification of the works than is possible via the DTN method, although it is to be established just how much faster it can deliver the message as at the previous working group it was said that "bulk jobs would still need to be uploaded the night before they were happening" – working in a similar parameter to sending a flow via the DTN. If the application is being bespoke built to deliver this one function, which is a notification to DNOs of the planned de-energisation of metering equipment, then it seems pointless as Solution 1 can already provide this notification. This also avoids the costs involved with implementing a new solution, as the DTN system already exists. If the app described in Solution 2 intends on providing more than this single function, potentially looking to replace other DTN functions, or even DTN itself, then it is outside of the scope of this working group	Thank you for your comments. The Code Manager notes that the majority of industry participants sending the DTN option would not be a DCUSA party. Solution 1, as stated in the REC Solution Document, does not work for all scenarios, particularly agents carrying out comms hub replacements as they are not required to have access to the DTN. Solution 2 has the potential to be scoped for other areas of work. If it is taken forward the REC will raise a separate CP or Issue in due course.
Northern Powergrid (Distribution Network Operator)	Solution option 1 (market message) uses existing technology and infrastructure and is the standard form communication between parties so would be the pragmatic solution. However, as it is not real time, and for the reasons outlined in the report, it has limitations since it will not cover all scenarios.	Thank you for your comments.

	Solution 2 (App) is an aspirational solution that will cover all scenarios but will likely take much more time to develop and implement. So, if this change proposal is accepted solution 1 would be the short term preference with a view to developing an App for this and possibly other scenarios in the future.	
Scottish Power (Energy Supplier)	Although we understand the purpose of this change and the benefits to Distribution Network Operators (DNOs), we need to ensure that DNOs can fulfil their obligations without incurring significant costs to the suppliers. We believe that the DNOs should take this information directly from the DCC. It takes about an hour approximately, for any onsite metering work to be completed. If DCC could send an alert to DNOs, an hour after the AD1 alert to indicate that the power supply is off then DNOs can take appropriate action to contact the customer as it would be a fair indication of the genuine power outage. In any case, where there is an outage that has not been triggered by any planned works, the customer would most times contact either the Supplier or the DNO. Our proposal of DCC contacting DNOs an hour later the power outage alert is received, should be discussed and explored in the next working group meeting. This option may require changes to the existing DCUSA obligations placed on the DNOs following receipt of the power outage alerts. **Comments on the two proposed solutions**: we believe that both solutions are complex and expensive for the energy suppliers to implement. We are also concerned that industry may be adding more complexity to an already complex process. Although we are not in	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC. A decision on how Solution 2 is funded has not been made yet and will form part of the business case and further consultations.

	support of either solution, if we were asked to pick one of the options then we would prefer the data flow option. Solution 1 – Although we agree with REC code managers assessment of the solution 1: 1) that it cannot be sent real time, 2) there are other parties who are authorised to work on meters or carry out Communications Hub replacements that do not send market messages and 3) Concerns about Revenue Protection or Debt Collection Agents providing advance notice of attending site due to the potential sensitive nature of these jobs. We believe that introduction of a market message is a cost-effective option for the suppliers compared to the API or the webservice option. The second solution option - introduction of an online application and/or API to send notifications, seems to be an expensive option for the suppliers. There is also significant security risks associated, all party users will have to have their own security measures. We are also concerned about the amount of data suppliers are expected to send to the DNOs and this could potentially create problems.	
Alt HAN Co (Crowded Meter Room Co-ordinator)	Alt HAN Co doesn't have a strict preference, as we function on behalf of Energy Suppliers, it is for them to determine their preferred approach. The obligation to notify will be met by our appointed CMR MEMs on behalf of Alt HAN Co.	Thank you for your comments. The scope of DCP419 has changed and has now moved to any communications interruption (including replacing Communications Hubs) and is not limited to

	We note that Option 1 has been through significant discussion and an earlier assessment, utilises a data flow via the DTN which is a well understood, secure and consistent approach to managing cross industry communications and data sharing. An initial impact assessment has already been undertaken to establish the likely cost and benefits of this option. The DCUSA DCP419 change targets a very specific scenario of cases that would enable DNOs to safely ignore AD1 alerts where a SMETS2 or Comms Hub has been de-energised as part of planned works. Option 2 would require further development to establish, procure, develop, test and install an app. One of our CMR MEMs noted a preference for Option 2 and expressed a view that Option 1 introduces unnecessary 'touchpoints' in addition to adding potential time delays. Where Data Flows may be required 'same day', many systems run on processing cycles limiting how quickly the notifications can be sent. Their view states Option 2 removes reliance on the Data Transfer Network and allows for real-time event driven notifications either on-day, day-1 or on job scheduling. Having reviewed both options against their Work Management systems and processes, they have outlined a preference for solution option 2.	de-energisations only. This is because it is not possible to differentiate between AD1s generated due to meter de-energisation or a Communications Hub replacement.
National Grid Electricity Distribution (Distribution Network Operator)	While option 2 does allow all parties the ability to send the required message there have been no details of timescale to achieve the option or costs.	Thank you for your comments. Solution 1, as stated in the REC Solution Document, does not work for all scenarios, particularly agents carrying out comms hub

	As a DNO receiving the message is the priority as work on the comms hub replacements is due to start in 2025 and therefore the DTN flow option would be the quickest to implement. Therefore NGED would prefer option 1 to be the preference.	replacements as they are not required to have access to the DTN.
OVO (Energy Supplier)	Due to the huge amount of work upon Suppliers to achieve the replacement of all the affected 2G/3G communications hugs as part of the sunsetting activities by the Mobile Network Operators, neither option is feasible or acceptable to Suppliers as it will exponentially increase both the cost and resource burden upon us to achieve, all to overcome a flawed process that is being used by DNO's to identify there has been a power cut. The AD1 sent to them is an indicator that power is lost but actually only explicitly confirms the CH has lost power for many reasons. It being seen as always declaring a power cut is an inaccurate view and needs additional context the DNO's have access to, to enable them to establish if there is an actual power cut needing addressing. If the DNO do not have the ability, other than the AD1, to establish the power has been lost needing them to contact the customer, then that needs picking up via the SEC groups to cover this off and changed be made to the Smart Solution to enable that to take place. An obligation in the REC and under DCUSA, based on what the SEC has set out is following a very disjointed governance route creating additional cross code challenges.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC. This will include a review of any new or revised reporting that has been implemented via the SEC since DCP419 was initially raised.
Anonymous Metering Equipment Manager	Our preference is for discounted option 3. Option 3 is the only option that deals with the root cause of the issue. I0216 is a DNO problem, so it there should be changes to the SEC regulations and DNO processes to resolve it.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution

	It seems unfair that options 1 and 2 are even being considered, as these are passing the responsibility and costs onto MEMs, even though the problem does not affect us. Options 1 and 2 are both costly changes. Neither option offers any benefit to MEMs. If we were forced to choose, we prefer option 2 over option 1.	was de-scoped and to understand any engagement that has been had with SEC.
SSE Energy Supply (Energy Supplier)	In addition to the drawbacks listed for solution 1, we also think there are additional complications with this solution: 1. Multiple parties sending the dataflow could cause conflicting information on the planned power outage. 2. Not all jobs will go ahead as planned which would not solve the declared problem statement. 3. The receipt of and actioning of dataflows is not always carried out in a timely manner. With these points SSE feel option 2 is the better option.	Thank you for your comments.
Calisen Metering Services (Metering Equipment Manager)	Given that we are a supplier agent, working on behalf of the energy supplier - we consider that the responsibility should be with the energy supplier to notify the respective DNO of the appointment not any third party.	Thank you for your comments.
ENGIE (Energy Supplier)	We prefer option 2.	Thank you for your comments.
Electricity North West (Distribution Network Operator)	Would prefer option 1 as incumbent and most practical solution from a cost and time perspective.	Thank you for your comments.

UK Power Networks (Distribution Network Operator)	UK Power Networks believe both proposed solutions have positives and drawbacks to them. Solution one limits the users to only users currently able to send market messages, which could lead to communication hub installers not being able to send this new market message, but does build upon existing infrastructure. Option two a web app or api that anyone that undertakes work can utilise in both an emergency/short notice scenario as well as for more planned in advance work would help with increased usage and uniformity. In addition this solution could be developed to communicate with the DCC directly allowing these messages to then be sent as alerts to the relevant parties and ingested by existing systems, thus reducing development required. UK Power Networks preference would be for Option two from the two options provided.	Thank you for your comments.
IMServ (Metering Equipment Manager)	Note IMServ's response in in our capacity as a Metering Operator Agent (MOA) / Metering Service, Safe Isolation Provider (SIP), and Crowded Meter Room MOA (CMRM). The drop down option above does not support the population of multiple roles. In terms of the solution, while IMServ are comfortable and familiar with market messages, there are clear benefits from using an App/API i.e. real-time + accessible to all parties who need it. Option 2 would be our preferred solution; we are mostly interested in implementing the API as we expect to automate the triggering of notification message into our job scheduling systems.	Thank you for your comments.

	We appreciate that some parties may wish Technicians to manually trigger the notifications from an App on phones, however this is not something we would hope to avoid, driven by factors such as… • We have a large number of Technicians to manage/train/audit • Techs jobs are very time sensitive, additional manual tasks are to be avoided • Manually driven tasks increase the chance of failure	
Scottish Power Energy Networks (Distribution Network Operator)	SPEN's preference is for option 1, to introduce new data flow/market message to be sent over the DTN; Option 1 makes use of the current industry standard communications tool between all DCUSA parties, the Data Transfer Network. SPEN understands that this would be fairly cost effective to deliver on and would also be faster to implement. Of course there may be benefits to an overarching system to incorporate all data flows in real time, that however is subject to considerably higher investment and authority within SPEN and is therefore out of the scope of this consultation.	Thank you for your comments.
British Gas (Energy Supplier)	Both solutions address the problem to some extent. For organisations who already have built the capability to issue market messages this may be a more efficient solution to implement. However the API solution would allow for near real time updates to cater for emergency work and could offer real time validation and handshakes meaning we can be sure messages have landed correctly.	Thank you for your comments.

Question 3:	Do you agree the proposed solutions address the problem statement, including if either solution addresses the problem statement more effectively than the other?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	Both would address the problem statement but option 2 would be better for all parties involved and will allow freedoms where emergency or ad hoc work needs to take place. Option 2 would also address where suppliers attend sites with no intention of disconnecting but for emergency or unexpected reasons they do have to, it may still mean there are disconnections that cannot be pre notified due to how the work is being carried out etc but it will help to ensure the number is reduced significantly and in a more robust way than option 1. We do not agree with the problem statement being correct as it is not something that is an issue for suppliers and the only party that will benefit from this change are the DNO's. It is important to note, if an obligation is put on suppliers to pre notify of all jobs where de-energisation could occur this could result in site visits not taking place where this requirement cannot be met. This will result in potential unnecessary costs where jobs have to be aborted and an overall impact on the customer.	Thank you for your comments. The Code Manager is also exploring with Ofgem what their expectations are with the DNO obligations in the Ofgem Regulatory Instructions and Guidance (RIGs) and if there is scope for these to be adjusted.
E.ON Energy Services (Metering Equipment Manager)	Both solutions would address the problem statement however, cost-benefit analysis needs to be conducted. Both will require significant development, and we do not yet know the benefits.	Thank you for your comments.

Scottish and Southern Electricity Networks (Distribution Network Operator)	SSEN feels that both solutions address the problem statement, but we feel that the DTN option addresses the statement better purely in the fact that we do not have an app/API developed that is ready to progress the solution. It is easy to imagine all of the things the app could do, but without an early design or an illustration of costs/lead times, the two aren't comparable.	Thank you for your comments.
Northern Powergrid (Distribution Network Operator)	Yes, to a level both solutions will address the problem statement. For the reasons referenced in Q2 solution 2 will better address the statement overall.	Thank you for your comments.
Scottish Power (Energy Supplier)	Although we agree that the proposed solutions address the problem statement, we believe alternative options must be explored to ensure DNOs are able to fulfil their obligation without incurring significant cost to the suppliers. Our preference is for DNOs to take this information directly from the DCC instead of all industry parties incurring significant costs implementing changes to their systems and processes. This option seems simple and less complicated compared to the two proposed solutions.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC.
Alt HAN Co (Crowded Meter Room Co-ordinator)	We believe option 1 effectively addresses the problem statement in that it ensures that DNOs are notified before any planned works by the relevant party, which provides useful information to the DNO regarding how they manage their obligation to investigate and contact customers during power outages.	Thank you for your comments.

	Option 2, requires further development, but in principle it should be able to support DNOs in managing their obligations, but DNO feedback from this IA will determine if it adequately meets their needs. One of our CMR MEMs have stated that they believe both proposed solutions address the problem statement but due to the limitations of Option 1, they believe that Option 2, an API, would be more effective.	
National Grid Electricity Distribution (Distribution Network Operator)	Solution 1 would cover the majority of alerts if they were sent ahead of time to the DNO. A system of acceptance could be agreed between parties as to how far ahead of appointments details could be sent.	Thank you for your comments. Any SLAs will have to be developed as part of the solution as the REC requirements are expected to be subject to performance assurance.
OVO (Energy Supplier)	n/a	n/a
Anonymous Metering Equipment Manager	As mentioned in question 2, we disagree with both option 1 and option 2. Our preference is for discarded option 3.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC.
SSE Energy Supply (Energy Supplier)	SSE feel solution 1 does not meet the problem statement but solution 2, depending on the final design should be able to.	Thank you for your comments.
Calisen Metering Services (Metering Equipment Manager)	We are supportive of the need to address the issue where consumers may not have a working comms hub and be impacted however, do not believe this issue exists currently or will exist, as we understand in the main that DNOs are not taking action off the back of these alerts now.	Thank you for your comments.

	Therefore should the problem statement be revised to consider the need for the obligation as opposed to introducing a fix for something which is not an issue.	
ENGIE (Energy Supplier)	Both options address the problem statement, but Option 2 addresses it more effectively as it provides a route for all parties who may make interventions on meters to notify DNOs that they are carrying out the work. It is also faster than sending data flows and avoids hand-offs between agents and suppliers. It is also likely to be more cost and time effective than creating a new data flow, especially in the context of MHHS.	Thank you for your comments.
Electricity North West (Distribution Network Operator)	Yes they both address the issue but DTN already has the existing capability to create this notification. The introduction of an app would add additional cost and require further consideration that should really come under a separate proposal and review.	Thank you for your comments.
UK Power Networks (Distribution Network Operator)	UK Power Networks agree that the proposed solutions address the problem statement, we believe that solution two addresses the problem more effectively due to its ability to be used by a wider user base and that it could be built into the existing DCC network instead of going down the market message route.	Thank you for your comments. Using existing DCC infrastructure would likely require all users to be SEC Users, which has the same limitations for Comms Hub Replacement Agents who are not required to register under any Code.
IMServ (Metering Equipment Manager)	The issue is only fully addressed when all DNOs are acting on the AD1 alerts, is it safe to assuming this the absence of the proposed notification (DCP419) the only barrier, could there other issues, for example; could actioning AD1 notifications be cost or field resource prohibitive for DNOs?	Thank you for your comments. The feedback received from DNOs during the DCP419 Work Group under DCUSA is that it is the volume of AD1s that are unmanageable. Removing the obligation for

	If the notification message is not the only barrier, is there's a risk that time and money will be spent, but it won't change the situation in respect to AD1's.	DNOs to contact Consumers where it is known that planned works were occurring would allow them to manage this much easier. It would also improve the Consumer journey, as they wouldn't be contacted unnecessarily.
Scottish Power Energy Networks (Distribution Network Operator)	Yes since option 1 makes use of the current industry standard communications tool between all DCUSA parties, the Data Transfer Network.	Thank you for your comments.
British Gas (Energy Supplier)	We agree that both solutions presented address the problem. The main advantage of Solution 2 is that this would enable "same day" notifications to be sent to the DNO. It would also enable other Parties who do not currently send Market Messages to send notifications to the DNO. If possible and the cost/benefit supports it both solutions could be progressed to give industry maximum flexibility to provide prior notification of activity.	Thank you for your comments. The Code Manager will consider raising an alternate to this change, allowing both solutions to progress further before final recommendation.

Question 4:	Are there any alternate solutions that would better meet the needs of the problem statement?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	DNO's contacting customers off the back of the AD1 alerts as per their obligations. They could also engage with Ofgem to understand if there is a time limit of when they would be expected to contact customers (e.g. if no restoration alert received within 60mins) after receiving the AD1 alert to ensure compliance. We would expect that better analysis of the AD1 alerts, supported by AI, would enable DNO's to more effectively manage the AD1 alerts that they receive and target customers that are actually at risk. We are yet to see any evidence that all DNO's are contacting every customer off the back of AD1 alerts or any view of plans on how they will meet the obligation if this change does not go through.	Thank you for your comments. The Code Manager is also exploring with Ofgem what their expectations are with the DNO obligations in the RIGs and if there is scope for these to be adjusted.
E.ON Energy Services (Metering Equipment Manager)	An alternative would be to amend the DNO obligation to follow up on all power outage alerts; could disregarding the alerts be an option if power was restored within a certain timeframe (having regard to customers in vulnerable circumstances and multiple alerts).	Thank you for your comments. The Code Manager is also exploring with Ofgem what their expectations are with the DNO obligations in the RIGs and if there is scope for these to be adjusted.
Scottish and Southern Electricity Networks (Distribution Network Operator)	SSEN feel that the DTN solution that has been discussed at the working group is the best current solution, considering factors such as time to implement, cost to implement and that the DTN is the industry	Thank you for your comments.

	recognised industry communications tool and is used by all DCUSA parties. Other alternatives such as using the DCC to create a new alert/suppress on their end have been explored but are not suitable. With MHHS and DIP being the new way to communicate market messages between all industry parties, it should be explored that a new IF/PUB message be developed to potentially be introduced as a way of providing this data. This solution fits with the architecture of MHHS. It could be added to an existing MHHS message or could be set up as its own.	The Code Manager will take away an action to see if a DIP message is more appropriate than a DTN message.
Northern Powergrid (Distribution Network Operator)	Not to our knowledge	Thank you for your comments.
Scottish Power (Energy Supplier)	We believe that DCC and DNOs should work together to get this information. Any planned meter work would mean, there would be a power outage for appx 1 hour. Once the meter is installed or comms hub replaced, the meter will be commissioned and DCC would get a notification from the supplier about the new meter. Instead of supplier/MOPs sending this information to the DNOs, DCC could send a message to DNOs an hour later in case the power is not re-stored. This requires potential changes to the existing DCUSA obligation placed on the DNOs following receipt of the power outage alerts. There are two options, either DCC sends an alert to DNOs or there should be a mechanism where the DNOs can send an MPAN to DCC to find out what's happened, as DCC has full visibility of our smart meters.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with the SEC.
Alt HAN Co (Crowded Meter Room Co-ordinator)	We have previously proposed an alternative solution which would be specific to CMR activities utilising the CMR Frontier system. DNOs	Thank you for your comments.

	could be given access to Frontier and they could view upcoming planned jobs and MPANs that would be de-energised, helping them to plan and manage their obligations. This solution is specific to CMR related de-energisations and would be expected to be available some time this year.	
National Grid Electricity Distribution (Distribution Network Operator)	A way to suppress alerts direct with the DCC could be a solution, though costs and timescales to achieve this would be prohibitive we feel.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC.
OVO (Energy Supplier)	There are many alternative solutions that will not move the burden on to Suppliers that do not seem to have been progressed or set out anywhere as part of this RFI. Section 4 of the Solution Development Report states a SEC Modification was ruled out due to the cost and timescales. The only way to establish the costs of a modification is to actually raise a SEC Mod. Being that none has been raised to address this issue, it is unclear how the costs and timescales stated as being the reason this option was ruled out were established? The process to obtain both of those elements has not been initiated or undertaken via the SEC Change process itself. The fundamental issue that requires a solution is the AD1 itself is being used to state there IS a power cut needing DNO action. Even though it is acknowledged and is the reason for these changes in the RFI, that the AD1 WILL also be triggered in other very valid, and none DNO impacting, circumstances but the DNO cannot, or will not, be able to identify the difference. Has work been undertaken, especially at the correct SEC / DCC forums, to establish methods that DNO's CAN	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC.

	establish an AD1 is due to a CH replacement and not a loss of power to the meter? If these have been carried out, they need to be referenced, and the outcomes documented. If the Smart solution set out is missing elements, there are routes to follow to get those investigated and resolved. They don not seem to be documented here so have they been done elsewhere to enable those impacted to understand why this is seen as the only way to get the required information to enable identification that the AD1 is a valid power loss situation and not a CH replacement?	
Anonymous Metering Equipment Manager	Our preference is discarded option 3.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC.
SSE Energy Supply (Energy Supplier)	Not at this time.	Thank you for your comments.
Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	We still feel that more consideration could be given to our originally favoured option, which is noted in this consultation as an alternative that was discussed (to amend the requirements on the DCC to only send the AD1 notification in certain circumstances – for example, if a power outage was registered but was restored within one hour). This option has been discounted on the grounds of cost but it is not entirely clear to us where these costs lie, and both Option 1 and Option 2 will incur costs as well.	Thank you for your comments. The REC Code Manager will take an action to speak with DCUSA on why a DCC solution was de-scoped and to understand any engagement that has been had with SEC.

Electricity North West (Distribution Network Operator)	There may be an option to use the DIP rather than DTN which can operate on a real-time basis.	Thank you for your comments. The Code Manager will take away an action to see if a DIP message is more appropriate than a DTN message. However, this will not resolve the issue around Comms Hub Replacement Agents not being required to send flows.
UK Power Networks (Distribution Network Operator)	UK Power Networks currently operate a web application that around two thirds of all suppliers / Meter Operators (MOPs) and Safe Isolation Partners (SIPs) currently use. It is currently designed to take reports of Category A and B defects with an enhanced suite of information which is sometimes not able to be included on a traditional data flow or market message. This application runs on a low cost and allow reports to be raised in real time or in advance. The application could easily be adapted to support “Smart Meter Isolation” this message would then come direct to ourselves. This solution has zero cost to Suppliers or Users to log in and use the application and could pave the way for a simple industry-wide solution that redirects the end message based on MPAN area. Due to this solution already being partly live and adopted by a large user base, it would be quicker to roll out and test initial benefits and use cases without large industry investment or longer development time.	Thank you for your comments.
IMServ (Metering Equipment Manager)	None.	Thank you for your comments.
Scottish Power Energy Networks	No.	Thank you for your comments.

(Distribution Network Operator)		
British Gas (Energy Supplier)	It is clear from responses to earlier consultations issued by DCUSA that the development cost and ongoing operational costs incurred by all industry parties to provide DNO with advance notice of work on Smart Meters or Comms hubs will be significant. This needs to be compared with the savings made by the DNOs from not unnecessarily contacting customers where a AD1 alert has been received and we would expect to see a full cost benefit analysis to be produced. We do not consider that enough focus has been put on alternative solutions by the DNOs. We would like to see other options put forward by the DNOs such as better triaging of AD1 alerts before contacting customers. DNOs could also proactively send message to nearby meters to test whether there is a wider supply fault to their system before contacting customers. We would also suggest that this change is limited to domestic smart metered customers only. This would reduce some of the additional costs that will be incurred such as re-negotiating third party agent contracts who are appointed to non-domestic customers where new obligations will need to be included.	Thank you for your comments.

Question 5:	Do you think we have identified and considered all processes and scenarios that may be impacted through the implementation of the proposed change?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	In some respects, yes, as it covers any work that requires pre notification. However, there are other potential industry changes that are going to be heavily impacted by the implementation of DCP419 such as 4G rollout	Thank you for your comments. Comms hub replacement was the reason Solution 2 was investigated and as such is not out of scope of the solution.
E.ON Energy Services (Metering Equipment Manager)	We need to consider TCSO CH swap outs – it was raised at SEC comms transition group 17/03/2025 that although these do not deenergise the meter, removing the 2-3G CH causes an AD1 alert to be sent to the DNO and we are advised its not possible to differentiate between these and a power outage. As the solution currently stands suppliers/MEMs would not be expecting to send prenotification of these. It is probable that suppliers will be doing these swaps out reactively.	Thank you for your comments. Comms hub replacement was the reason Solution 2 was investigated and as such is not out of scope of the solution.
Scottish and Southern Electricity Networks (Distribution Network Operator)	SSEN believe that these have been identified fully at the working group. Alternative solutions were also discussed but deemed inappropriate to proceed with.	Thank you for your comments.
Northern Powergrid (Distribution Network Operator)	Yes	Thank you for your comments.
Scottish Power (Energy Supplier)	All maintenance work would trigger a AD1 alert	Thank you for your comments.

	• Meter location move • Meter fuse • Any major electrical work carried out by the customer or the supplier i.e. new fuse box installation • off-supply' message would be triggered to the DNO even when the MOP was merely changing the comms hub and hadn't withdrawn the cut-out fuse	
Alt HAN Co (Crowded Meter Room Co-ordinator)	We believe all relevant parties that may be in a position to notify DNOs have been captured. We have not identified any further CMR processes that need consideration as part of the proposed change.	Thank you for your comments.
National Grid Electricity Distribution (Distribution Network Operator)	Yes	Thank you for your comments.
OVO (Energy Supplier)	No, as the proposed solution is to put the burden on Suppliers instead of drawing out why DNO's cannot establish the AD1 is not to do with a power loss to the meter itself. Consideration of other elements is not set out.	Thank you for your comments.
Anonymous Metering Equipment Manager	For option 1, yes. For option 2, there is more detail needed, that would presumably come out during the app design and development.	Thank you for your comments.
SSE Energy Supply (Energy Supplier)	We believe so.	Thank you for your comments.

Calisen Metering Services (Metering Equipment Manager)	As discussed in question 3, has the work undertaken to date considered the need for the obligation and applicability of any solution now? If not, should this be agreed in advance of any other solution being proposed	Thank you for your comments.
ENGIE (Energy Supplier)	Yes.	Thank you for your comments.
Electricity North West (Distribution Network Operator)	Working group will have considered these and determined the viability of each.	Thank you for your comments.
UK Power Networks (Distribution Network Operator)	UK Power Networks believe that most processes and scenarios are considered by the implementation of this proposed change. We believe that one area currently being overlooked is the handling of historic notification of a planned interruption e.g. what happens if notification is provided for an interruption that has already begun. Another area is the rise of private EV and Solar installers isolating the customers supply via the main cut out fuse, and whilst this should be undertaken by a MOP / SIP or the supplier we are aware this is not always the case and therefore this should also be considered as part of the solution to potentially provide the correct procedures to these individuals via the system when a breach of process is identified.	Thank you for your comments. It was discussed at the Working Group that a secondary benefit could be increased notification of invalid or unsafe energisations (ie not by SIPs). REC / DCUSA would have to establish whether the reporting requirements on DNOs could be included with DCP419 / I0216 or if it would require a separate change.
IMServ (Metering Equipment Manager)	I understand that the solution is only applicable to 'Smart Meters', but it's not explicitly clear if this refers to SMETS 1, SMETS 2, or both. Do SMETS 1 meters have functionally to send AD1 errors? If not, does that mean it's only applicable to SMETS 2 meters and any SMETS versions which may come after SMETS 2?	Thank you for your comments. All DCC enrolled Smart Meters have the functionality to send AD1s.

Scottish Power Energy Networks (Distribution Network Operator)	Option 2 would place a considerable burden on networks to replace the existing DTN system and integrate the new app within existing customer service and smart meter work systems. There is an operational compromise with option 1 in that comms hub notifications may well mask genuine ad1 calls, the same risk would occur for comms hub agent no shows.	Thank you for your comments.
British Gas (Energy Supplier)	One of the difficulties parties have is knowing whether a de-energisation will be required before accessing the property. If an isolator switch has been previously installed a de-energisation of the meter may not be required in some cases. Where bulk uploads of pre-booked jobs are submitted it should be permissible for parties to assume that a de-energisation will be required in all cases and notification sent for all jobs. This will mean that DNOs may be pre-notified of a job but no AD1 alert is ever generated.	Thank you for your comments.

Question 6:	Do you believe the solution appropriately accounts for the industry's move to the new MHHS arrangements?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	We cannot see that this would be impacted by the transition to MHHS – meters will be de-energised/re-energised in the same circumstances that they are today, however the way that information about those events is shared will change (to use the Data Integration Platform (DIP) rather than the DTN). The main impact will be caused by the timing of this change as parties will be focussed on delivering the changes required to qualify for MHHS, and having to make changes for this is an unnecessary distraction.	Thank you for your comments.
E.ON Energy Services (Metering Equipment Manager)	We do not believe this has any bearing on MHHS arrangements	Thank you for your comments.
Scottish and Southern Electricity Networks (Distribution Network Operator)	We believe that Option 1 accounts for the industry's move to new MHHS arrangements. Not all market messages have been mapped to the DIP currently, so there is a reason for DTN to still be working in tandem with DIP for at least the foreseeable future. With that in mind, option 1 can be implemented faster and with less cost than an entirely new application to handle this one task can be, so is still an appropriate solution and in SSENs opinion the preferred one.	Thank you for your comments.
Northern Powergrid (Distribution Network Operator)	Yes	Thank you for your comments.

Scottish Power (Energy Supplier)	We do not support either proposed solution and recommend DNOs to explore solutions directly with the DCC. Whatever the agreed solution is, we would like the change to be implemented 6 months post the MHHS go-live, we propose the Implementation date of June 2026.	Thank you for your comments.
Alt HAN Co (Crowded Meter Room Co-ordinator)	n/a	n/a
National Grid Electricity Distribution (Distribution Network Operator)	Yes, however we would ask that our answer to question 10 is considered here.	Thank you for your comments.
OVO (Energy Supplier)	This solution has no bearing on MHHS or how Smart meters operate once MHHS is implemented.	Thank you for your comments.
Anonymous Metering Equipment Manager	No. See questions 9 and 10.	Thank you for your comments.
SSE Energy Supply (Energy Supplier)	We do not feel the move towards MHHS is impacted by either of the two proposed solutions.	Thank you for your comments.
Calisen Metering Services (Metering Equipment Manager)	We are unclear of the reference to MHHS – aside from the need for functioning smart meters to be in place, which is outside the scope of this issue.	Thank you for your comments. This is a standard REC impact assessment question currently, to ensure nothing impacts on the MHHS design, Code drafting or implementation that the Code Manager has not considered.
ENGIE (Energy Supplier)	Yes.	Thank you for your comments.

Electricity North West (Distribution Network Operator)	This change has no impact on the MHHS arrangements. The proposed solutions will potentially remove additional smart meter fault alerts from being sent through when work is being completed on the meter rather than address any settlement issue. The only concern from a MHHS perspective, is that the development and implementation of a solution could take resources away from the time critical activities to deliver the system testing and completion of the programme. This potential solution represents a lower priority to all parties at present but could be introduced once the MHHS Programme has been completed.	Thank you for your comments.
UK Power Networks (Distribution Network Operator)	UK Power Networks believes that the solution(s) appropriately account for the industry's move to the new MHHS arrangements.	Thank you for your comments.
IMServ (Metering Equipment Manager)	Option 1 utilises existing DTN flows, although this communication method is being retained its use is declining, arguably creating new DTN flows is at odds with MHHS. Option 2 seems to be a solution which can operate outside both the existing and MHHS arrangements, so it feels separate altogether	Thank you for your comments.
Scottish Power Energy Networks (Distribution Network Operator)	Yes.	Thank you for your comments.
British Gas (Energy Supplier)	We have not identified any impact to the MHHS arrangements	Thank you for your comments.

Question 7:	For solution option 1, do you have any comments on the proposed market message?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	We do not agree that option 1 should be progressed at all. However, our main area of feedback would be that it appears a flow would be sent from MEM/CMC to suppliers, which does not make sense. Suppliers do not require a flow and removing this aspect may reduce the cost to implement for the industry.	Thank you for your comments. There was feedback in the DCP419 DCUSA Work Group that it may be beneficial for Energy Suppliers to also receive this flow, but this can be re-evaluated. The supplier scenario receiving variants allowed full sharing across all parties.
E.ON Energy Services (Metering Equipment Manager)	There is a field for customer cancellation. Is the intention that a second flow is sent when an appointment is cancelled? If so, why only customer cancellations? If this is not the intention, we are unsure why this data item is required. We believe appointment type is not relevant information for the DNO. We should adhere to GDPR principles of data minimisation and only share data that is required for a specific purpose (for example if this is a debt related visit, this is sharing information about a customer the DNO does not need to know).	Thank you for your comments. Can you please confirm where you are seeing these additional fields, as the proposed new Data Flow in the REC Solution Development Report only includes MPAN, Appointment Date and Additional Information?
Scottish and Southern Electricity Networks (Distribution Network Operator)	SSEN feel that this is the correct solution to the problem statement. DTN is already recognised as the industry standard communications tool between DCUSA parties. It is already integrated into the systems	Thank you for your comments.

	all party's use. It will have a faster lead time to develop and SSEN believes it will be cheaper in cost to achieve. Electralink will need to develop the new market message, and this will be shared in the DTC update. This could happen potentially as early as June this year. Then it will be on parties to ensure this flow is adopted and recognised by internal systems. It could also be feasible to use a pre-existing flow with a new data element added, potentially avoiding the need to create a new flow all together, but this would need to be decided on by Electralink	If there is a pre-existing flow that could be used, please confirm.
Northern Powergrid (Distribution Network Operator)	Yes. The data flow has a DNO to Supplier variant but the description and notes is all about DNO receiving the updates. What is the scenario where the DNO would need to send a data flow to the supplier?	Thank you for your comments. There was feedback in the DCP419 DCUSA Work Group that it may be beneficial for Energy Suppliers to also receive this flow, but this can be re-evaluated. The DNO to supplier scenario variant allowed full sharing across all parties.
Scottish Power (Energy Supplier)	• Customer agreed appointment date – suppliers may not have this information as their agent would arrange or re-arrange appointments directly with the customers. • There is a risk of a genuine power outage before and after the planned work, at what point, DNOs require the information? • We would like to know how many days in advance suppliers are expected to send this data flow and the notification.	Thank you for your comments. If the appointment date was agreed between the MOA and the Consumer, it is expected that the MOA would send the flow. The legal text has not yet been drafted, but the Code Manager expects this would be 1 Working Day before the appointment is due to occur and the notification would be sent by the MOA, SIP, etc rather than the supplier as they will know the confirmed date.

		The Code Manager will take away to review the risk of power outage on the day of the appointment and DNOs not contacting that Consumer.
Alt HAN Co (Crowded Meter Room Co-ordinator)	No further comments.	n/a
National Grid Electricity Distribution (Distribution Network Operator)	The ability to send the market message sent in bulk for multiple sites by one party would be a good option. Clarity on timescale for delivery and receipt of the message would be useful to be able to factor in to systems.	Thank you for your comments. The legal text has not yet been drafted, but the Code Manager expects this would be 1 Working Day before the appointment is due to occur.
OVO (Energy Supplier)	Currently the smart meter journey in replacing a CH is not linked, at all. to any market messaging, so this would need to create such a link – we don't inform any party via the DTN of this activity so have not need to direct any systems and processes this direction. This would need to be managed as a complete separate function in Supplier organisations to enable this to be viable. As noted in the Solution Development document, the DTN is not real time and will not enable Suppliers to notify the DNO of any work done same day or qat short notice. It will create an overhead as part of the work that will not consider how we operate or the ability to carry out work ad hoc. It will also prohibit using parties that do not use the DTN at all, also noted in the document. Or require a complicated interaction with those parties and the Supplier to enable this.	Thank you for your comments.

Anonymous Metering Equipment Manager	Option 1 will be considered a medium sized system change. The implementation of a new dataflow will require significant development and testing resource.	Thank you for your comments.
SSE Energy Supply (Energy Supplier)	Sending an unnecessary copy of the new dataflow to the supplier would increase workload, changes to our system and ultimately costs (which would be passed on to customers). We do not believe amendments should be made to our systems as this change has been raised to ultimately allow a DNO to comply with the RIGs set by Ofgem.	Thank you for your comments. There was feedback in the DCP419 DCUSA Work Group that it may be beneficial for Energy Suppliers to also receive this flow, but this can be re-evaluated. The supplier scenario receiving variants allowed full sharing across all parties.
Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	We do not support Option 1, but have no comments on the message.	
Electricity North West (Distribution Network Operator)	It is the simplest and most potentially a more cost effective method to implement a solution to this proposal As part of the Change Impact assessment (for either DCP419 or the subsequent REC Change proposal), a detailed cost assessment should be produced by the service providers to understand the relative cost differentials on the value created for customers.	Thank you for your comments. The business case assessment will be laid out in the next stage of the REC Change Report.
UK Power Networks (Distribution Network Operator)	UK Power Networks believe that the use of market messages to deliver this data flow restricts and reduces it user base too significantly for it be the best solution to this problem statement.	Thank you for your comments.

IMServ (Metering Equipment Manager)	The foot notes refer to ‘Smart Meters’, is this both SMETS1 and SMETS2?	Thank you for your comments. This is any Smart Meter enrolled with the DCC.
Scottish Power Energy Networks (Distribution Network Operator)	The market message should indicate that parties are temporarily adjusting or de-energising the Communications of a Whole Current or Smart Meter.	Thank you for your comments. As AD1 alerts only occur on Smart Meters enrolled in the DCC, the scope will not be widened to include Whole Current meters.
British Gas (Energy Supplier)	The new market message could be further simplified by removing group BBB and making group AAA two data items MPAN Code and Customer Agreed Appointment Details. We also do not see the value of including additional information. What would be expected to be populated here ?	Thank you for your comments. The Code Manager will take this away to review.

Question 8:	For solution option 2, do you have any comments on the proposed API/app?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	To be able to fully understand the impact we require a more in depth cost benefit to be put forward from DNO's to be able to confirm with internal stakeholders that this is the most cost effective option to progress forward	Thank you for your comments. The business case assessment will be laid out in the next stage of the REC Change Report.
E.ON Energy Services (Metering Equipment Manager)	Solution 2 would be more challenging if its going to be app only as our Field technicians would need to switch between apps on their device and would need to use a device which is compatible with the app. If it includes both an app and an API then we could extend our own app to call the API.	Thank you for your comments.
Scottish and Southern Electricity Networks (Distribution Network Operator)	Whilst SSEN are not against the development of an application to handle this task, we do ask the question: should that proposal not be expanded with a view to handle all communications traffic and not just be created for this singular issue? It does not seem correct to develop an application to provide a function that DTN can already provide. If there is scope to develop an application to replace DTN, we would support this being explored, but it is outside of the scope of this working group. The application/webapp option is a larger project and a potentially large expense for whoever is hosting it, plus all REC and DCUSA parties. It needs significant effort to design, and it must meet	Thank you for your comments. It will not be assumed that REC can develop this, this will follow the RECCo procurement process– as do all RECCo services. Solution 2 is not intended as a replacement for the DTN but instead is a solution to the many identified Parties who are not required to use the DTN. This was discussed at Working Group 15.

	the needs of all parties as well, because of this cost and effort to deliver this application it should be tendered work and it shouldn't be assumed that REC/Gemserv can develop this. Further to this, it also comes with a significant implementation effort that option 1 doesn't come with. DTN is the industry standard communications tool to handle these types of communication.	
Northern Powergrid (Distribution Network Operator)	Not at this stage.	Thank you for your comments.
Scottish Power (Energy Supplier)	As a supplier we are looking for a cost-effective change and therefore do not support this solution. We would like to know if it is a shared API? Or there will be a separate point to point API for each DNO? As highlighted above, there are significant security risks associated at each point-to-point connection; all users will have to have their own security measures.	Thank you for your comments. The API has not been developed yet, but the plan is to have a shared API rather than point to point ones, similar to the EES API. This would also allow a GUI type interface and a look up on EES data.
Alt HAN Co (Crowded Meter Room Co-ordinator)	One of the CMR MEMs has expressed a preference for this solution.	Thank you for your comments.
National Grid Electricity Distribution (Distribution Network Operator)	There are currently a couple of DNOs using or developing an app for MOAs to send in images of defects identified on site, it could be a possible solution to have one app that covers multiple work streams for the MOAs.	Thank you for your comments. REC would like to discuss this further with the DNOs that already are using or developing a solution to establish synergies and lessons learnt.
OVO (Energy Supplier)	This solution assumes the agents will have equipment that will have access to external systems to allow for this API? How has that been established and analysis carried out? It also assumed the agent will access the EES on site. This is a change and would need analysis to	Thank you for your comments. As part of the DCP419 DCUSA Working Group, it was established that it should be

	establish any issues with remote access to an agent who does not need this information to complete their activities today and how this would work going forward. Without any of this being understood or being looked at, it is impossible to understand that impacts of this being feasible. Noting MPAN is considered personal information so would require a level of DPA and rules to protect the data end to end. Suppliers have no control over their agents devices or systems if they are not internal, so this could inhibit the organisations able to undertake this work. Being that this is over and above the systems in use to complete the CH replacement and all associated TCSO activities, all via the DCC, it may not be possible to implement.	possible for on-site agents to access an app from their handheld device or a phone. The App/API will require a link to the EES API, which can be done via a REC Data Access Request.
Anonymous Metering Equipment Manager	Option 2 will be considered a medium sized system change. Option 2 will affect Field Operatives. Until we know the API/app details, it is difficult to comment. We would request that the API/app can be auto-populated whenever possible. The app must be quick and easy to use on a field hardware device or mobile phone.	Thank you for your comments. The App/API will require a link to the EES API, which can be done via a REC Data Access Request. This should allow MPAN/address/Meter Serial Number to be automatically populated if one of these data items is entered. The API is expected to work without input by a field operative.
SSE Energy Supply (Energy Supplier)	We feel the introduction of an APP/API solution removes the problems listed for solution 1 and meets the need for real time notification from multiple parties which cannot send dataflows. There were concerns raised under the DCUSA working group in relation to the information which should be sent to the DNO for this solution, we believe that the only data item which should be required to be provided to the DNO is the MSN, as this will provide the correct indication of the meter being	Thank you for your comments. The data items currently planned in the API/App are MPAN, Meter Serial Number, address and date of appointment. Only one of MPAN/address/Meter Serial Number would need to be entered, with the

	worked on. We do not believe other data items will need to be provided, reducing the risk of GDPR concerns	others being automatically populated via the EES API. This allows for greater freedom for the on-site agent entering the information, depending on what information they have access to.
Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	No comments.	n/a
Electricity North West (Distribution Network Operator)	This option has potential but as noted above, would potentially represent additional costs from the potential option 1 solution. l As part of the Change Impact assessment (for either DCP419 or the subsequent REC Change proposal), a detailed cost assessment should be produced by the service providers to understand the relative cost differentials on the value created for customers.	Thank you for your comments. The business case assessment will be laid out in the next stage of the REC Change Report.
UK Power Networks (Distribution Network Operator)	UK Power Networks would suggest the further exploration on whether any solution developed could be integrated directly into the DCC network in order for alerts to be sent via that established infrastructure.	Thank you for your comments. Using existing DCC infrastructure would likely require all users to be SEC Users, which has the same limitations for Comms Hub Replacement Agents who are not required to register under any Code.
IMServ (Metering Equipment Manager)	None, other than the API must function independently from the App, as at this stage our intention is to use the API rather than the App	Thank you for your comments.

Scottish Power Energy Networks (Distribution Network Operator)	The cost to deliver the option 2 is uncertain with respect to investment and implementation time scales. There are of course clear benefits to a modernised portal system for network operations, but is this within the scope of this consultation? Whilst suppliers can deploy non DCUSA-REC party comms hub agents should they not also provide adequate systems for them to send and receive all the necessary operational data. Suppliers can then communicate with REC/DCUSA parties on their behalf.	Thank you for your comments. In the case of the proposed DTN flow, it is not within the remit of the REC or DCUSA to dictate how Energy Suppliers manage the Comms Hub rollout. Some Energy Suppliers have confirmed that as there is no requirement for Comms Hub Replacement Agents to be CoMCoP qualified as they are not breaking meter seals, and as such no requirement for flows to be sent. They will provide their Comms Hub Replacement Agents with lists of addresses and not pre-booking appointments.
British Gas (Energy Supplier)	We would need to understand how the API would work and then build into contractual obligation for 3rd parties, as this development would sit outside of Centrica. As this obligation would fall on a 3rd party rather than us as a supplier clarification would be needed as to the complexity and build. We have encountered commercial issues with use of the ENA Connect Direct portal in that there are uncapped un-capped indemnity clauses included in the user agreement meaning we are unable to use the system.	Thank you for your comments.

Question 9:	What lead time would be required for your business to implement either proposed solution? Please provide justification and specify if different for each solution option.	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	n/a	n/a
E.ON Energy Services (Metering Equipment Manager)	We estimate six months - this would likely require development from a software provider and interfacing work, along with testing before development	Thank you for your comments.
Scottish and Southern Electricity Networks (Distribution Network Operator)	Option 1) We estimate 7-10 working days for SIMS (SSENs outage management system) integration and around 10 working days for C&C to make any development changes in Unity Messenger. We would also estimate a further six to eight weeks to ensure communication between the backend tables and SIMS and to make sure the market message is working correctly. As DTN is a trusted and known system this would be the much shorter of the two to implement. Option 2) It is extremely hard to comment on how long SSEN would need to make development changes as the application/webapp does not currently exist. Option 2 also brings potential staff coaching and training. If there is to be an option to manually check the application for cancellation of jobs or new alerts 'in the moment', something that was discussed at the working group, this would bring costs itself; including time spent monitoring the use of the application to ensure its adoption has become a part of our BAU. SSEN would estimate it would take a minimum of six months to set up a project and required systems to	Thank you for your comments. Reporting of job cancellations was descoped following discussions at the Working Group, as there would be no requirement for DNOs to follow up on notified appointments where an AD1 is then not received. DNOs can choose to use the API or the GUI so it is for them to determine the need for coaching or training as both solutions provide new information.

	ensure that the new application/webapp can effectively communicate messages to our outage management system, but this in reality could be a lot longer. We would need more information on the development specifications to comment more accurately, but we do not currently have those.	
Northern Powergrid (Distribution Network Operator)	Minimum 6-month lead time for dataflow implementation for solution 1. Option 2 is unknown at this stage,	Thank you for your comments.
Scottish Power (Energy Supplier)	We do not support either proposed solution and recommend DNOs to explore solutions directly with the DCC. Whatever the agreed solution is, we would like the change to be implemented 6 months post the MHHS go-live, we propose the Implementation date of June 2026.	Thank you for your comments.
Alt HAN Co (Crowded Meter Room Co-ordinator)	One of the CMR MEMs who will be providing these notifications on our behalf when undertaking CMR works confirmed that either proposed solution would require a lead time of approximately 6 months. Either option requires Alt HAN Co to agree the additional activity under the existing CMR contracts and update our processes and validation to ensure the obligation has been met.	Thank you for your comments.
National Grid Electricity Distribution (Distribution Network Operator)	Based on current workloads combined with an estimation of how long it would take for development and implementation, our minimum estimated lead time for implementation would be approximately 6-9 months based on solution option 1. Solution option 2 would be take significantly longer than this.	Thank you for your comments.
OVO (Energy Supplier)	Due to the lack of detailed information as to how either solution will operate in both the Supplier and agent organisations, it is not possible	Thank you for your comments.

	to establish how long it will take to implement. There are considerable changes to both systems and processes needed for each solution, affecting both internal and external elements, that mean we are unable to provide a guess based on the information provided.	
Anonymous Metering Equipment Manager	Our resources are currently focused on MHHS readiness. Option 1 needs the same resources as MHHS. If option 1 is chosen, we would appreciate a long lead time between change approval and implementation. Option 2 is harder to specify until more details are known. Option 2 will need to be rolled out to field staff, so needs a moderate lead time.	Thank you for your comments.
SSE Energy Supply (Energy Supplier)	Solution 1 which requires an update to our system would require at least six months lead time from the date of approval. Solution 2 will require minimal lead time as changes would be required to documentation only. However it should be noted that as the agents will be required to use the APP/API if that solution is taken forward, contracts may need to be amended which could increase the lead time needed to implement this change.	Thank you for your comments.
Calisen Metering Services (Metering Equipment Manager)	No lead time if we were to send this information to energy suppliers as we already send details of booked appointments.	Thank you for your comments.
ENGIE (Energy Supplier)	Option 1 will take time as it will require liaison with software service providers, an implementation plan and training for staff in how to use the flow. Option 2 would require no lead time for our business as under Option 2 we (as a supplier) are not required to send data flows. All that would be	Thank you for your comments.

	required would be a briefing to frontline staff on the introduction of the API for awareness.	
Electricity North West (Distribution Network Operator)	We would recommend that the standard technical solution change timelines should be used. i.e. 6 months after the approval of the Change.	Thank you for your comments.
UK Power Networks (Distribution Network Operator)	UK Power Networks would require approximately 4 - 6 months to implement solution one and set up a process to handle the new market messages. UK Power Networks would require approximately 8 – 12 weeks to implement solution two and setup a new business process to handle these notifications. UK Power Networks would like to note that if solution two was able to integrate and utilise the existing DCC network, this could reduce our implementation time to as little as 2-4 weeks. In addition, UK Power Networks believe that our existing web application for reporting Category A and B defects could be further developed in a similar 6-10 week timeframe to report Smart Meter Isolations.	Thank you for your comments.
IMServ (Metering Equipment Manager)	Minimum 6 month lead time, but 12 months would be preferable. Changes will be required to existing scheduling software and all development resource is occupied for the foreseeable future with MHHS	Thank you for your comments.

Scottish Power Energy Networks (Distribution Network Operator)	Unknown at this point - Would require going through an internal IT solution review. We would only initiate exploring options once the outcome of DCP419 is known.	Thank you for your comments.
British Gas (Energy Supplier)	12 to 18 months This is based on the fact that we have a number of different systems across our entire IT infrastructure that schedule jobs that would be impacted by this change. We also use third party agents who would need to implement the change to become compliant. We are dealing with a number of differing parties, whilst running a metering procurement exercise and also preparing for Market Wide Half Hourly settlement. Third parties tend to utilise the same key personnel to do all work and their time is likely to be limited.	Thank you for your comments.

Question 10:	Do you foresee any risks to your MHHS implementation, qualification or migration plans caused by the delivery of this change?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	Any change within the MHHS timescales and especially during the qualification phase through to M14 is a risk and the unclear benefits of this change mean that there isn't a case for making this change before M14.	Thank you for your comments.
E.ON Energy Services (Metering Equipment Manager)	We do not foresee any risks to MHHS	Thank you for your comments.
Scottish and Southern Electricity Networks (Distribution Network Operator)	There is currently a change freeze on MHHS that would prevent anything being introduced prior to the planned go live date in September 2025, so that it won't impact Implementation plans. Provided the chosen solution does not introduce a new system, then SSEN do not believe it would impact qualification either, as all existing SSEN systems have been through SIT & therefore qualification. It also shouldn't impact migration as it would typically be delivered as part of a quarterly DTC change. A new flow would only require the system ingesting it to be changed to accept the data. So, there should be no impacts to the plans. It is doubtful that the second option would be able to be implemented, as it involves an entirely new application. It is likely that the Programme would not accept it due to the change freeze.	Thank you for your comments. The MHHS Code Freeze only impacts Core Systems in the MHHS Programme. For the REC this is the CSS, ERDS, EES and SDES. More information can be found on the REC Portal here. Communications Hub Replacement Agents will not be required to use the DIP so has the same limitations as a DTN flow.

	As mentioned in our answer to question 4, we believe that the IF/PUB solution would be a worthy and viable one, potentially being more cost effective. All parties will be making use of this method of communication, so SSEN feel it is imperative we explore this as part of the working group.	
Northern Powergrid (Distribution Network Operator)	There is an industry change freeze so this change should not be progressed until post MHHS go-live.	Thank you for your comments.
Scottish Power (Energy Supplier)	No	Thank you for your comments.
Alt HAN Co (Crowded Meter Room Co-ordinator)	n/a	n/a
National Grid Electricity Distribution (Distribution Network Operator)	We would suggest that a DTN flow would be the simplest to implement given the potentially tight deadline (in relation to the 2G to 4G CH Replacement Project in 2025) and would have minimal impact on our MHHS Programme. Our concern would be that a market message could have more of a significant impact if there are implications associated with the design artefacts. In addition, with MHHS migration starting this year, we'd be reluctant to introduce a new market message until that has been proven. However in the longer term, a MHHS market message would make more sense from a future-proofing aspect, assuming that all DTN flows will be replaced with Market Messages over time.	Thank you for your comments.
OVO (Energy Supplier)	Outside the risks of having to delay being able to actually replace the 2G CHs with 4G CHs that WILL impact MHHS, there are no other risks. If Suppliers need to implement either option, that risk could materialise as we would need to include considerable work, and system / process	Thank you for your comments.

	changes to comply outside of just focusing on the huge task of managing the 4G replacement activities already on our plates. That risk extends far further than just MHHS and could impact the planned work to hit the deadlines of the 2G sunsetting.	
Anonymous Metering Equipment Manager	Yes, as mentioned in question 9, our resources are focused on MHHS. Option 1 will have a greater impact on our MHHS resources than option 2. It is for this reason that we prefer option 2 over option 1.	Thank you for your comments.
SSE Energy Supply (Energy Supplier)	No.	Thank you for your comments.
Calisen Metering Services (Metering Equipment Manager)	No impact due to MHHS	Thank you for your comments.
ENGIE (Energy Supplier)	We see more risks from Option 1 as it involves changes to the DTC in the run up to MHHS and would be a distraction for suppliers in the qualification phase. Option 2 is a self-contained solution which would not interact with MHHS impacted services like the DTN and as such should present less risks to MHHS implementation.	Thank you for your comments.
Electricity North West (Distribution Network Operator)	The only concern from a MHHS perspective, is that the development and implementation of a solution could take resources away from the time critical activities to deliver the system testing and completion of the programme. This potential solution represents a lower priority to all parties at present but could be introduced once the MHHS Programme has been completed.	Thank you for your comments.

UK Power Networks (Distribution Network Operator)	UK Power Networks do not foresee any risks to our MHHS implementation, qualification or migration plans caused by the delivery of this change.	Thank you for your comments.
IMServ (Metering Equipment Manager)	It shouldn't be an issue, but MHHS will take priority over this change.	Thank you for your comments.
Scottish Power Energy Networks (Distribution Network Operator)	No.	Thank you for your comments.
British Gas (Energy Supplier)	The MHHS implementation is a key priority for Centrica. This proposal would impact a number of different systems and could therefore impact on key resources currently allocated to the MHHS programme. Our preference would be for this change not to be implemented until MHHS migration is completed.	Thank you for your comments.

Question 11:	Would implementing either proposed solution incur any costs to your business? If so, please provide details and specify if different for each solution option. If preferable, please indicate which of the below ranges your costs may fall: A) Nil; B) Up to £9,999; C) Between £10,000 and £49,999; D) Between £50,000 and £99,999; or E) more than £100,000.	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	Yes, but we are unable to fully understand the cost to us without more detail on what the App/API will look like and how it will be accessed. This change will only introduce a cost to suppliers and no benefit.	Thank you for your comments.
E.ON Energy Services (Metering Equipment Manager)	We estimate D) Between £50,000 and £99,999. This is our high level estimate.	Thank you for your comments.
Scottish and Southern Electricity Networks (Distribution Network Operator)	For solution Option 1 - Market Message this would be a minimal expense as we already utilise this option. We estimate this would be either A) Nil or B) Up to £9,999. For solution Option 2 - APP and/or API this would be at an expense so D) Between £50,000 and £99,999	Thank you for your comments.
Northern Powergrid (Distribution Network Operator)	Yes. The costs would depend on the agreed solution and how the information is processed. We estimate the costs would be B or C for solution 1 but unknown for solution 2 at this stage.	Thank you for your comments.

Scottish Power (Energy Supplier)	We need to ensure that DNOs can fulfil their obligations without incurring significant costs to the suppliers therefore we do not support either proposed solution: Solution 1 - DTN – D – between £50,000 and £99,999 Solution 2 - API - E - more than £100,000	Thank you for your comments.
Alt HAN Co (Crowded Meter Room Co-ordinator)	Both options have cost implications for our CMRMs but we have not had a cost estimate at the time of response submission.	Thank you for your comments.
National Grid Electricity Distribution (Distribution Network Operator)	B) Up to £9,999. This is mainly taking into account staff labour costs, and is estimated depending on the exact changes required. We estimate that the work will take approximately 4 weeks to complete, again depending on the exact specification of the solution.	Thank you for your comments.
OVO (Energy Supplier)	n/a	n/a
Anonymous Metering Equipment Manager	Option 1 would be a significant one-off cost. We are likely to automate the process, so ongoing costs would be minimal. Option 2 would also be a significant one-off cost, but likely cheaper than option 1. Option 2 will also have ongoing costs due to the extra time needed for Field Operatives to use the new app.	Thank you for your comments.
SSE Energy Supply (Energy Supplier)	Solution 1 would likely cost in the range of £50,000 an d £ 99,999 . Solution 2 would likely cost Up to £9,999	Thank you for your comments.

Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	Option 1 – up to £9,999 Option 2 – Nil	Thank you for your comments.
Electricity North West (Distribution Network Operator)	Opt 1 – minimal cost as DTN already in situ so would estimate B) Opt 2 – Unknown without a full cost analysis but would tentatively guess in the region of D) to cover the end-to-end development and implementation costs.	Thank you for your comments.
UK Power Networks (Distribution Network Operator)	UK Power Networks believe the costs of solution one to be in bracket C - £10,000-£49,999 UK Power Networks believe the costs of solution two to be in bracket B – up to £9,999	Thank you for your comments.
IMServ (Metering Equipment Manager)	n/a	n/a
Scottish Power Energy Networks (Distribution Network Operator)	Unknown at this point - Would require going through an internal IT solution review. We would only initiate exploring options once the outcome of DCP419 is known.	Thank you for your comments.
British Gas (Energy Supplier)	As previously mentioned this change impacts multiple system across Centrica. We estimate that 4 systems could be impacted and we estimated each system would be more than £100,000 per system.	Thank you for your comments.

Question 12:	Taking into consideration both the costs and the benefits seen by your organisation, do you consider this change should be made? Please specify if you have differing opinions for each solution option.	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	No. As per answers to previous questions there is no cost benefit to suppliers for implementing this change. The only party that would benefit are DNO's and this would only be the assist them to meet and obligation they are currently not compliant with	Thank you for your comments.
E.ON Energy Services (Metering Equipment Manager)	We understand the benefit this provides to DNOs with them avoiding investigating power outages unnecessarily, however we are not aware of any benefit to our business or our customers that would justify the cost and effort of implementing either solution. A cost/benefit analysis needs to be completed including the costs the DNOs are currently incurring following up on these alerts, and what this would be reduced to with implementation verses the cost of development across all suppliers/MEMS. We do not believe this change should be implemented until this has been completed.	Thank you for your comments. The business case assessment will be laid out in the next stage of the REC Change Report.
Scottish and Southern Electricity Networks (Distribution Network Operator)	The greatest benefit is the one that providing notification will bring to customers. This will allow SSEN to follow the conditions set out in the RIIGS. It also enables us to meet SLAs around guaranteed standards of service. We must attend outages within an agreed timescale, so waiting to see if a restoration alert is provided following an outage alert eats into that time, so as a solution this is off the table. That is why a solution needs to be applied to the problem statement. It is SSENs belief that	Thank you for your comments.

	option 1 is the preferred solution and we do believe that the change should be made. The DTN already exists, and we forecast minimal costs to adopt the solution and expect a much quicker lead time to adopt a new market message into our process. SSEN believes the application/webapp solution will require a much longer lead time, with unknown costs. It is not comparable as the application does not currently exist, neither has it had any planning bar a presentation at the last working group. If the development of the application/webapp is expanded to something greater than purely a system to deliver one type of communication, which another industry approved communications tool can do, than this then becomes something that could be explored outside of the working group as another change. SSEN would be happy to be a part of that working group to explore how an application/webapp could bring benefit to all DCUSA/REC parties.	
Northern Powergrid (Distribution Network Operator)	Yes. In the interests of customer service, Suppliers should notify the DNOs of pre-planned supply interruptions. Given that both the DNO and the customer concerned would be aware of the supply interruption, the DNO would not need to contact the customer to check whether the customer is without power. The obligation on the DNOs to contact the customer as soon as reasonably practicable after receipt of a single premises outage alert from a smart meter that is currently in Annex F (Interruptions) to the RIGs could, therefore, be amended to confirm that the obligation does not apply in circumstances where the DNO has received such a pre-planned supply interruption notification from the Supplier.	Thank you for your comments.

Scottish Power (Energy Supplier)	Although we understand the purpose of this change and the benefits to Distribution Network Operators (DNOs), we need to ensure that DNOs can fulfil their obligations without incurring significant costs to the suppliers. As a supplier, we do not see any benefit of this change and therefore do not believe that this change should be made. As mentioned in our response to other questions of this RFI, we would like DNOs to explore options with the DCC to fulfil their DCUSA obligations.	Thank you for your comments. The business case assessment will be laid out in the next stage of the REC Change Report.
Alt HAN Co (Crowded Meter Room Co-ordinator)	In the case of CMRs, only a relatively small volume of notifications are expected to be needed, this is because CMR seeks to address rooms where not all suppliers have been able to install smart metering yet. For CMR specific activity the DNOs could have an alternative mechanism to check when works are scheduled by using Frontier. If Suppliers and DNOs determine they want to implement DCP419 then Alt HAN Co will make the necessary changes via the CMR MEMs. One of our CMR MEMs noted, from their perspective as a MEM and SIP, there is there is no direct benefit accruing to them of implementing this change. They further note both solutions will incur costs to implement and manage, but are unclear on the benefits.	Thank you for your comments.
National Grid Electricity Distribution (Distribution Network Operator)	Yes. Although we would expect to see a positive cost-benefit ratio, we would also welcome the improvement it would bring to the consumer experience during a planned outage. If DNOs are contacting consumers unnecessarily, likely wasting valuable time and resources in doing so, this could also potentially present a somewhat inept appearance to the consumer who would be likely to assume that all parties would be aware of a planned outage.	Thank you for your comments.

OVO (Energy Supplier)	We do not feel either option should be progressed. While we are mindful of the work DNO's are required to undertake and fully supportive of that, the route being taken here is using a data item that was not designed to provide them the information they require and are relying upon. Placing the cost and impact on Suppliers to address that lack of functionality in the solution needs further investigation and discussion at the appropriate forums and committees. An understanding as to why the SEC route has not been followed, when that is the Code that governs how Smart operates, would be welcomed.	Thank you for your comments.
Anonymous Metering Equipment Manager	I0216 offers zero benefit to us. Options 1 and 2 are both medium sized changes with significant costs. Our preference is therefore to make no change, or to use discarded option 3.	Thank you for your comments.
SSE Energy Supply (Energy Supplier)	As a supplier solution 1 would not benefit our customers or us financially. The purpose of the change is to comply with a RIG set out by Ofgem, this RIG does not specify a time in which the DNO must contact the customer, although it states 'as soon as reasonably practicable'. It is not clear what process DNO's take to comply with this RIG and conversations held within the DCUSA WG show that each DNO takes a differing view on the time taken to contact the customer. After a POA is received and the supply is restored, a Power Restoration Alert is issued, it is also not clear from the change that the DNO waits a specific time for a PRA to be issued. We appreciate there is a need to comply with the RIG but we believe that prior to any costly changes being made to systems, processes ahead of this change should be	Thank you for your comments.

	assessed to ensure there is consistency across all DNO areas and reduce the overall cost of complying with those obligations.	
Calisen Metering Services (Metering Equipment Manager)	This would not impact us as we already have to send data to suppliers of booked appointments. If it was expected that Agents are responsible for sending these messages, that would impact our business and we would need to re-consider our answer.	Thank you for your comments.
ENGIE (Energy Supplier)	We would still prefer further investigation into the "time out" approach for reducing the number of notifications to DNOs and would like to understand what the costs are that have led to this option being discarded. If it really isn't an option, then we can see the case for change but our view is that Option 2 delivers this more cost effectively and at lower risk than Option 1.	Thank you for your comments.
Electricity North West (Distribution Network Operator)	This change would allow for a better process on both the industry and customer behalf, gives a clear view of planned works so they don't get incorrectly investigated as faults, no need to track outages and restoration since we know this incident is due to pre-notified site work. It is better to use the existing option (DTN) for this since costs would be minimal, more easily quantifiable and the integration would be more seamless. The app, if already available, would be better but as its currently only an idea the additional requirements would need to be considered outside of this proposal. DTN therefore is the only viable choice between the two current options	Thank you for your comments.

UK Power Networks (Distribution Network Operator)	UK Power Networks believe there is a clear benefits case for this change as the average cost of UK Power Networks attending a power outage site visit is over £300. Anything to reduce these visits and the handling of erroneous power outage alerts is a direct benefit to us. UK Power Networks believe this change should be made, but further technical discussion and agreements should be made and concluded prior to progressing with either solution currently offered.	Thank you for your comments.
IMServ (Metering Equipment Manager)	From a MOA', SIP or CMRM's perspective there no obvious benefit, but we recognise the potential benefit for other parties. We suspect there could be risk that we are implementing a process where we move lots of customer appointment info to DNOs, but the end result is that DNOs simply have more data.	Thank you for your comments.
Scottish Power Energy Networks (Distribution Network Operator)	SPEN are not planning on implementing either of these solutions at this time. We don't action customer contact based on a single Power Outage Event Alert.	Thank you for your comments.
British Gas (Energy Supplier)	Whilst we understand the potential for an improved customer experience we do not believe the benefits outweigh the costs for our organisation. It has not been demonstrated that there is an overall benefit to consumers by implementing this change.	Thank you for your comments.

Question 13:	For DNOs: on average over the past 12 months, how many AD1 notifications have you received per month? If your organisations covers more than one area, please provide a breakdown per area.	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	n/a	n/a
E.ON Energy Services (Metering Equipment Manager)	n/a	n/a
Scottish and Southern Electricity Networks (Distribution Network Operator)	Into our Adapter we received 1,492,169 over the 12 months. This is 124,347 a month. SSEN believe this question does not tackle the issue in the problem statement which is focused on single premises power outage alerts. Had this question been put to the working group before the RFI was issued, we could've all agreed on a question that would be suitable in gathering information to help support finding the right solution. This question does feel a bit of a wasted opportunity.	Thank you for providing this data. These impact assessment questions were provided to DCUSA and the DCP419 Work Group chair on 05 February 2025, 15 Working Days before the impact assessment opened.
Northern Powergrid (Distribution Network Operator)	AD1 volumes for 2024: Yorkshire 426341 North East 257222 Total AD1s 683563	Thank you for providing this data.
Scottish Power (Energy Supplier)	n/a	n/a

Alt HAN Co (Crowded Meter Room Co-ordinator)	n/a	n/a
National Grid Electricity Distribution (Distribution Network Operator)	n/a	n/a
OVO (Energy Supplier)	n/a	n/a
Anonymous Metering Equipment Manager	n/a	n/a
SSE Energy Supply (Energy Supplier)	n/a	n/a
Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	n/a	n/a
Electricity North West (Distribution Network Operator)	n/a	n/a
UK Power Networks (Distribution Network Operator)	On average over the last 12 months, the monthly average of AD1 notifications received by UKPN is 231,927. This is split across our three license areas as follows: EPN - 123,555, LPN – 32,967, SPN – 75,405	Thank you for providing this data.
IMServ (Metering Equipment Manager)	n/a	n/a
Scottish Power Energy Networks (Distribution Network Operator)	Average per month; SPD: 20,194	Thank you for providing this data.

	SPM: 45,569	
British Gas (Energy Supplier)	n/a	n/a

Question 14:	For DNOs: what is the average cost per contact for each Consumer?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	n/a	n/a
E.ON Energy Services (Metering Equipment Manager)	n/a	n/a
Scottish and Southern Electricity Networks (Distribution Network Operator)	£3.54 per inbound/outbound call taking place. This calculation was put together by taking the total salary and operational costs associated with the customer contact centre and then dividing by the total contact. Please note that the monetary values used were from a 2022 figure. In a similar vein to the previous question, SSEN does not believe asking this question tackles the issue set out in the problem statement. It is not just a cost saving exercise, this working group wanted to focus on the benefit this change brings to customers, especially potentially vulnerable ones. Adopting this change means we can use our resource correctly to achieve critical SLAs in emergency response times and also that we are adhering to the RIIGS. There is also a potential cost which is much greater of visiting sites that we believe could have a fault. For example, if we receive a single premises power outage alert, try to contact the customer to no avail, so attend what we believe to be a fault to find that the metering equipment has been de-energised for supplier/MEM works to be carried out, we are using resource in a place	Thank you for providing this data. These impact assessment questions were provided to DCUSA and the DCP419 Work Group chair on 05 February 2025, 15 Working Days before the impact assessment opened. DCUSA did not provide any further impact assessment questions they wished to be included.

	where we needn't have. If we had received notification prior, then we would be making the decision not to attend.	
Northern Powergrid (Distribution Network Operator)	Most contacts are via text which costs c.2.5p per text.	Thank you for providing this data.
Scottish Power (Energy Supplier)	n/a	n/a
Alt HAN Co (Crowded Meter Room Co-ordinator)	n/a	n/a
National Grid Electricity Distribution (Distribution Network Operator)	As every interaction with a consumer varies significantly, our reporting is currently unable to differentiate so it is difficult to track this from a cost point of view at present. That said, this is work in progress so we would endeavour to provide the required information when it is possible to do so. However in the meantime, perhaps the information required could be obtained from the Ofgem Regulatory Reporting Pack if this is deemed to be an appropriate mechanism to do so? Please do come back to us if not though, and we will assess what we can do from our end to assist further.	n/a
OVO (Energy Supplier)	n/a	n/a
Anonymous Metering Equipment Manager	n/a	n/a
SSE Energy Supply (Energy Supplier)	n/a	n/a
Calisen Metering Services (Metering Equipment Manager)	n/s	n/a

ENGIE (Energy Supplier)	n/a	n/a
Electricity North West (Distribution Network Operator)	n/a	n/a
UK Power Networks (Distribution Network Operator)	n/a	n/a
IMServ (Metering Equipment Manager)	n/a	n/a
Scottish Power Energy Networks (Distribution Network Operator)	Unknown at this time.	n/a
British Gas (Energy Supplier)	n/a	n/a

Question 15:	For MOAs, Energy Suppliers and SIPs: on average over the past 12 months, how many planned jobs have you been aware of per month where the site has a Smart Meter which has required to be de-energised or had a Communications Hub replacement?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	We have previously provided this data through DCP419. The data that is required to justify the change would be from DNOs on how many AD1s they currently get and what their current process is.	Thank you for your comments.
E.ON Energy Services (Metering Equipment Manager)	Approximately 1 million per annum.	Thank you for providing this data.
Scottish and Southern Electricity Networks (Distribution Network Operator)	Non DNO question	n/a
Northern Powergrid (Distribution Network Operator)	n/a	n/a
Scottish Power (Energy Supplier)	6,324	Thank you for providing this data.
Alt HAN Co (Crowded Meter Room Co-ordinator)	We would expect the number of notifications for CMR activities to be relatively low compared to other MEM activities as CMR seeks to resolve spatial constraints preventing installation of smart/Alt HAN.	Thank you for your comments.
National Grid Electricity Distribution (Distribution Network Operator)	n/a to DNOs	n/a
OVO (Energy Supplier)	It is unclear why this is being requested as it is not a question aligned to the change being looked at? De-energisation jobs are notified to the	Thank you for your comments.

	DNO via current industry processes. Upon the deenergisation we update the parties required and the DNO is one of them. We are unaware of any industry issues related to AD1's being triggered when a planned de-energisation has taken place. Is this a different Use Case needing work on the AD1 itself? Any 'planned' CH replacement is only undertaken to resolve an issue with communications on site. We are unaware of AD1 being triggered in this situation. We carry out CH replacements as a BAU activity today to replace CH's for Single Band CHs to Dual Band if the Gas Meter is out of range. Are AD1 being issued and causing problems to DNOs? This, again, seems to be a separate Use Case that needs separate investigation and discussion via the appropriate SEC Forums. This is not a DCUSA or REC issue as it is a BAU Smart activity defined under the SEC. Issues being encountered with that should be raised accordingly to ensure the correct stakeholders are involved.	This data is being requested so that the Code Manager can see how many potential AD1 notifications DNOs would not be required to contact the Consumer off the back of, if this change were implemented, to feed into the business case assessment.
Anonymous Metering Equipment Manager	No response.	n/a
SSE Energy Supply (Energy Supplier)	n/a	n/a
Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	When we responded to the original consultation, we had not had any.	Thank you for providing this data.
Electricity North West (Distribution Network Operator)	n/a	n/a
UK Power Networks (Distribution Network Operator)	n/a	n/a

IMServ (Metering Equipment Manager)	n/a	n/a
Scottish Power Energy Networks (Distribution Network Operator)	n/a	n/a
British Gas (Energy Supplier)	n/a	n/a

Question 16:	For MOAs, Energy Suppliers and SIPs: on average over the past 12 months, how many emergency jobs or other same day appointments have you been aware of per month where the site has a Smart Meter which has required to be de-energised or had a Communications Hub replacement?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	As above.	n/a
E.ON Energy Services (Metering Equipment Manager)	Approx 50k per annum.	Thank you for providing this data.
Scottish and Southern Electricity Networks (Distribution Network Operator)	Non DNO question	n/a
Northern Powergrid (Distribution Network Operator)	n/a	n/a
Scottish Power (Energy Supplier)	1,697	Thank you for providing this data.
Alt HAN Co (Crowded Meter Room Co-ordinator)	n/a	n/a
National Grid Electricity Distribution (Distribution Network Operator)	n/a to DNOs	n/a
OVO (Energy Supplier)	As with Q15, it is unclear what issues relating to the transmission of AD1s are being caused by Emergency activities? We are obliged to react to these calls and undertake the appropriate action to address the emergency situation, which may include replacing the metering and CH. Due to the nature of these jobs, they are not always recommissioned at	Thank you for your comments. This data is being requested so the Code Manager can see how many potential AD1 notifications DNOs would not be required to

	the same time and post work is needing to be undertaken. We do not replace CHs in an emergency situation in isolation. It will only be done if the meter needs replacing. Which ill then be accompanied by industry market communication as today. Issues being encountered with the operational activities being undertaken in an emergency situation need to be flagged to the appropriate forum for discussion with the correct stakeholders under the SEC with the DCC.	contact the Consumer off the back of, if this change were implemented, to feed into the business case assessment.
Anonymous Metering Equipment Manager	No response.	n/a
SSE Energy Supply (Energy Supplier)	n/a	n/a
Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	We do not have ready to hand statistics on this but we would expect the numbers to be very low as our portfolio of Smart meters is relatively low, we have not commenced systematic CH replacement yet and we conduct very few, if any, “Smart for Smart” replacements as our focus is on upgrading non-Smart to Smart.	Thank you for your comments.
Electricity North West (Distribution Network Operator)	n/a	n/a
UK Power Networks (Distribution Network Operator)	n/a	n/a
IMServ (Metering Equipment Manager)	n/a	n/a
Scottish Power Energy Networks (Distribution Network Operator)	n/a	n/a

British Gas (Energy Supplier)	n/a	n/a

Question 17:	Do you have any other comments relating to this Change Proposal?	
RESPONDENT DETAILS	**RESPONSE**	**CODE MANAGER COMMENTS**
EDF (Energy Supplier)	n/a	n/a
E.ON Energy Services (Metering Equipment Manager)	We have no further comments	n/a
Scottish and Southern Electricity Networks (Distribution Network Operator)	SSEN have concerns on why the questions making up this RFI were not discussed in a working group. The Chair and sponsor did not have sight of the questions before they were delivered. The questions in this RFI aren't sharp enough, essentially being open to interpretation meaning responses from parties will differ and the answers will not be comparable. As mentioned in our answer to question 4, we believe that the IF/PUB solution would be a worthy and viable one, potentially being more cost effective. All parties will be making use of this method of communication, so SSEN feel it is imperative we explore this as part of the working group.	Thank you for your comments. These impact assessment questions were provided to DCUDA and the DCP419 Work Group chair on 05 February 2025, 15 working Days before the impact assessment opened. The Code Manager will take away an action to see if a DIP message is more appropriate than a DTN message.
Northern Powergrid (Distribution Network Operator)	If this change is approved, Ofgem should be approached with a proposal to amend Annex F (Interruptions) to the RIGs to confirm that the obligation noted in our response to question 12 does not apply in	Thank you for your comments.

	circumstances where the DNO has received a pre-planned supply interruption notification from the Supplier.	
Scottish Power (Energy Supplier)	As a supplier, we do not see any benefit of this change. Both solutions are costly in different ways, we are not entirely sure if DTN is going to be more reliable, API is expensive. Customer agreed appointment date will be dependent on how the appointment is booked; it is possible for supplier to delegate this to the MOP. We suggest that DNOs and DCC should work together to explore options to fulfil DNO obligation. There should be some parameters for when the meter goes off supply for X amount of time, DNOs should react. Our proposed solution will significantly reduce the volume of alerts currently being received by the DNO, which will enable them to have a focussed response. In summary, due to the lack of benefit for the suppliers, significant implementation cost and complexity involved, we do not support this change.	Thank you for your comments.
Alt HAN Co (Crowded Meter Room Co-ordinator)	No further comments.	n/a
National Grid Electricity Distribution (Distribution Network Operator)	No further comments.	n/a
OVO (Energy Supplier)	It seems clear the issue being encountered here is the use of the AD1 when power to the communications hub is lost or removed. That is being used as an explicit view that there is a power cut and the customer needs a DNO intervention. That process seems to have	Thank you for your comments.

	overlooked the other valid and viable situations where an AD1 is triggered and this change is looking to address that but making it a Supplier obligation to resolve the lack of functionality. We would welcome more work to find out what DNO's can do to establish the true 'power' situation on site without needing Suppliers to tell them of their activities, be that via the DCC or by using the data they already have available to them, be that via the SSI or some other tool to establish what is taking place on site.	
Anonymous Metering Equipment Manager	No response.	n/a
SSE Energy Supply (Energy Supplier)	Whilst we appreciate there is a need for customers to receive a good experience from industry, we are not comfortable with the proposal to implement a change where the DNO is required to comply with a RIG but an agent is managed by a Supplier. A Supplier is accountable for their agents and whilst we believe that Solution 2 is the best solution to be implemented, we are concerned that although every effort will be made to ensure our agents provide the DNO with notification of the power outage, there is no guarantee that this will happen on each job booked. In these cases, will the supplier be responsible for these failings? We appreciate legal text has not yet been developed but we would like to see what the obligations are prior to this change being taken further forward.	Thank you for your comments. As with all parts of the Code, all REC Parties are responsible for agents working on their behalf.
Calisen Metering Services (Metering Equipment Manager)	n/a	n/a
ENGIE (Energy Supplier)	No further comments.	n/a

Electricity North West (Distribution Network Operator)	We would have preferred earlier notification of the questions since some lend themselves to ambiguity.	Thank you for your comments. These impact assessment questions were provided to DCUDA and the DCP419 Work Group chair on 05 February 2025, 15 working Days before the impact assessment opened.
UK Power Networks (Distribution Network Operator)	UK Power Networks do not have any further comments on this change proposal.	n/a
IMServ (Metering Equipment Manager)	No	n/a
Scottish Power Energy Networks (Distribution Network Operator)	Where this includes Revenue Protection and/or Debt Collection Agent emergency type event, notifications under either solution will provide Network Operators of useful information which we could use in the event the customer calls us to report alleged loss of supply.	Thank you for your comments.
British Gas (Energy Supplier)	The change proposal as raised under DCUSA identified a number of non-network fault scenarios that would trigger an POA to be sent to the Distributor. One of the scenarios identified was “Unauthorised removal of the Distributor supply fuse by an electrician undertaking electrical installations work in the consumer’s premise.” We believe that without more rigorous action taken by the DNOs to prevent unauthorised removal of the Distributor supply fuse this scenario could completely undermine to effectiveness of either proposed solutions. It is also unclear from the data supplied to date what proportion of the unnecessary calls will be eliminated by either solution. We assume the	Thank you for your comments.

	DNOs will have some data from their experiences to date from trying to contact customers, that could be shared to provide this. DCP 419 CP states "Within Ofgem's 'Regulatory Instructions and Guidance (RIG): Annex F – Interruptions' document, there is an obligation on Distributors as below: Section 2.11 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. In order to meet their regulatory requirements and to maintain a positive customer experience Distributors will need to receive prior notification of any planned supply de-energisations whichare being undertaken by DCUSA Parties in the course of their normal works." Whilst we agree that this change could improve the customer experience, this change is not required to enable the DNO's to meet their regulatory requirement.	