Title: AMO response to DECC's consultation: "Smart Metering Implementation Programme - A consultation on draft licence conditions and technical specifications for the roll-out of gas and electricity smart metering equipment"

Synopsis: To document the AMO's response

Date: 13th October 2011

Contents

1. Introduction

1.1. Purpose

This document is the response to the consultation from DECC dated 18th August 2011, seeking views on the "Smart Metering Implementation Programme - A consultation on draft licence conditions and technical specifications for the roll-out of gas and electricity smart metering equipment."[1].

This response is not confidential.

1.2. Background

The Association of Meter Operators (AMO) is a trade association representing the interests of its members. There are nineteen members[2] on the AMO who include all of the active electricity Meter Operators and the largest gas Meter Asset Managers. Many of these companies also own significant quantities of metering assets, either directly or through associated companies.

The term Meter Operator is used throughout this document to include both the gas metering term Meter Asset Manager (MAM) and the electricity term Meter Operator.

1.3. Member Involvement

Many of the AMO members are undoubtedly providing their own response directly to DECC. This AMO response does not necessarily represent the agreed views of every member on each issue. This response has been prepared by the AMO Consultant on behalf of the AMO members based on views expressed through individual discussion, meetings and written comments provided by members.

The AMO is grateful for being invited to participate in the many DECC smart metering programme groups and various workshops arranged by the DECC and, previously, Ofgem teams. The AMO has also submitted responses to a number of earlier consultations.

The AMO membership is grateful for the on-going dialog with DECC, including attendance at our meetings to discuss the smart meter programme. The AMO membership would welcome the opportunity to provide any further clarification or discussion of any of the issues raised by this response.

1.4. Key Messages

Meter Operators have serious concern that achieving safe installation of this volume of metering work is not possible in the proposed period.

The continuing lack of a clear plan, even subject to subsequent change, makes planning for all stakeholders extremely difficult. A plan is an essential component of any programme of this scale and complexity.

Prevention is better than cure - there should be substantial efforts to ensure interoperability upfront (at design/approval stage) and not adjudicate later. Once meters are installed the costs of rectification (recall/replacement) massively increases whereas the public credibility of the smart meter programme deteriorates.

AMO believes that DECC should promote a layered approach to the SMETS where the hardware and core functionality are resolved as soon as possible and the more burdensome or unclear functionality be added in later versions of the SMETS and where possible added remotely to the existing smart meter stock. This approach will allow the Foundation Phase to continue and will allow suppliers to gradually build up installation volumes and the smart metering workforce to ensure a smooth and successful start to the mass rollout phase of the Programme.

1 www.decc.gov.uk/en/content/cms/consultations/cons_smip/cons_smip.aspx
2 www.meteroperators.org.uk/members.php

2. Questions & Answers

Question	Response
1. The Government is seeking new evidence and views on the impacts of specifying a completion date that is in the earlier part of 2019.	The functionality rich nature of the smart meter technical specifications combined with the creation and implementation of the DCC will mean the foundation phase must deliver a huge amount of activity and progress. There is also a significant dependency on European agreement. So much so that the rollout is unlikely to begin in significant volume until 2014. This leaves less 6 years for the installation of 50 million domestic smart meters. For this reason, a completion target of the end of 2019 is already ambitious and should not be brought forward. ***Meter Operators have serious concern that achieving safe installation of this volume of metering work is not possible in the proposed period.*** ***The continuing lack of a clear plan (even subject to subsequent change, makes planning for all stakeholders extremely difficult. A plan is an essential component of any programme of this scale and complexity.*** *See full response in later section of this document*
2. Do you think the licence conditions (AA1-2) as drafted effectively underpin the policy intention to complete roll-out of Smart Metering Equipment by a specified date? Are there any areas where you consider further clarification is necessary? Please explain your reasoning.	*No comment*
3. Do you agree that the licence conditions as drafted effectively underpin the policy intention to deliver Smart Metering Equipment with the functionality and interoperability required to meet the business case? Please explain your reasoning.	*No comment*
4. Do you agree that Smart Metering Equipment should be compliant with the SMETS at the time of installation and that it should continue to be compliant with that	It is impractical for equipment which is held in stock for a long period of time as a new version of SMETS may be issued whilst the equipment is 'on the shelf or in the van.' The requirement should be for Smart Metering Equipment to be compliant with the current version of SMETS at the point of manufacture. This will avoid operational field issues to manage SMETS versions. The 20 year experience of BSC Metering Codes of Practice has been a

Question	Response
version of the SMETS through the operational life of the equipment? Please explain your reasoning.	change proposal is agreed with a future implementation date. This give all stakeholders the opportunity to procure equipment to the new specification and use all stock in the logistics chain, prior to the implementation date. In the smart environment allowance must also be given for completion of any assurance activity. Requirement changes are not retrospective, so equipment already installed can remain, and equipment removed can be re-installed (subject to its remaining practical life) at another premises. This is essential to minimise stranding risk/cost. As components of the smart metering system within a property may have various installation and replacement dates the requirements must to ensure new versions are backwardly compatible for up to [20] years. The smart metering equipment may be firmware upgradeable for changes in SMETS where this is needed to support the Energy Supplier or Network requirements, but we should not insist on compliance to new SMETS versions where there are hardware impacts. Except in exceptional circumstances.
5. Do you agree that in some exceptional circumstances suppliers should be required to retrofit Smart Metering Equipment that has already been installed? Please explain your reasoning.	During Foundation stage it is agreed that the industry will be fitting meters which have communications until the DCC & DCC service providers are operational. All this communication equipment should be adopted by DCC, but where it is not then the affected party should be reimbursed. Who and how would the government determine the need to change any of the smart metering system? The cost benefit analysis would need to be clear. If MAPs are forced to replaced serviceable equipment then they should be recompensed for the loss of revenue. Is changing the WAN module once to be costed in, but what are 'exceptional circumstances' Will depend on appraisal of the exceptional circumstances and the associated commercial impacts. E.g. if it's for Network benefits who will pay for the upgrade exercise?
6. Do you think that the licence conditions (AA3-6) as drafted effectively underpin the policy intention for the new and replacement installation of Smart Metering Equipment? Please explain your reasoning.	*No comment*
7. What period of notice do you think would be appropriate before the new and replacement obligation comes into effect? Please explain your reasoning.	*No comment*
8. What contribution do you think the interoperability licence condition as drafted could play in ensuring	It is extremely important to protect the consumer experience and optimise successful visits and AMO fully support this drafting The requirements should covers technical interoperability and commercial interoperability. The existing (last five years plus) commercial

Question	Response
that suppliers work together to ensure Smart Metering Equipment is interoperable? Please explain your reasoning.	arrangements have not supported the MAP charging very successfully. The implication is difficult to achieve. For example, the electricity working fine, but gas comes later how to make that work successfully when fitted 100m away from electricity meter – which supplier has to change or move the Communications hub, or fit further equipment? Short list of SM HAN and preferred technology for SM HAN where this is functional within the household. Agreement on checks for SM HAN suitability for the whole house even if it's only initially being fitted for one fuel.
9. Do you think the licence conditions as drafted effectively underpin the policy intention to ensure Smart Metering Equipment is interoperable? Please explain your reasoning?	*No comment*
10. What role could a dispute resolution mechanism have a role in ensuring interoperability? What key features should such a mechanism have?	The key feature of a dispute resolution should be to restore or establish full smart metering services to the consumer quickly. Supplier should procure, through their agents, 'approved' meters – but who take risk of it subsequently being found to not be compliant in some aspect – supplier, MAP, Manufacturer(s), DCC (approval role). Reality is testing will only go 'so far' so who takes it to the next stage. Who/how is it determined which piece of equipment is 'non-compliant'? In the early years there can be expected to be a series of issues emerging. Latterly this should decline as specifications evolve to become tighter/clearer. This is a significant role and will provide feedback that the specification is not explicit, leading to different interpretations. Meter manufacturer will not normally not accept any warranty for consequential costs for failure – revisit labour costs. As the risk/cost is excessive, maybe doubling the manufacturing cost of a meter. If the alleged incompatibility is an operational issue – don't know how to operate that piece of kit - then should be exonerated from concern. ***Prevention is better than cure - there should be substantial efforts to ensure interoperability upfront (at design/approval stage) and not adjudicate later. Once meters are installed the costs of rectification (recall/replacement) massively increases whereas the public credibility of the smart meter programme deteriorates.***
11. For the smaller non-domestic sector do you agree that where there is a Current Transformer meter then suppliers should be required to install advanced rather than Smart Metering Equipment? Please	Yes The relatively small number of CT metered premises in Profile Class 1-4 sector make it unreasonably expensive to justify development of metering equipment (including large isolation switches). Provision of Advanced meters is an established technology (16 years) together with the associated infrastructure to provide data to customers. This exception should equally apply for small non-domestic *and* the small number of domestic use CT supplied customers. Clarity would assist:

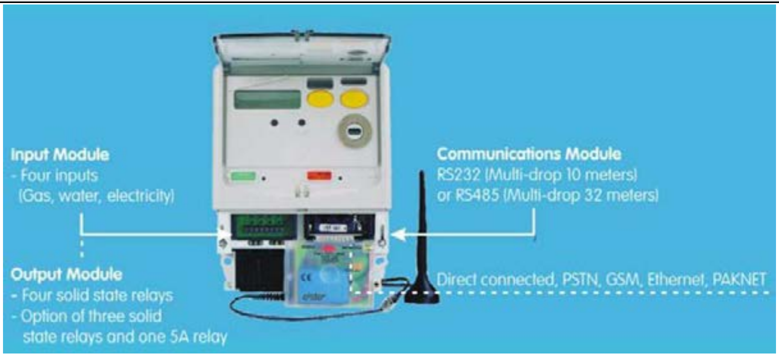
Question	Response
explain your reasoning.	Advanced meters: PC5-8 (existing licence obligation) PC1-4, CT metered Smart meters: All whole current meters, except those already covered by PC5-8 obligation
12. Do you think that the licence conditions as drafted effectively underpin the policy intention for Current Transformer meters? Please explain your reasoning.	*No comment*
13. Do you think under the new and replacement obligation gas suppliers should be given the option to wait for the installation of electricity Smart Metering Equipment before installing the gas Smart Metering Equipment? Please explain your reasoning.	The gas meter operative would need electricity network operator and/or supplier permission to connect a separate Communications Hub and the appropriate skills to carry out this work. This would effectively require a MOCOPA® skilled workforce. In addition installing a separate Communications Hub is likely to require more time on site than an intimate Communications Hub as in option 3b. Balancing whether to exploit the benefit of waiting until the electricity meter is in place against accepting a potentially more costly and less efficient installation (due to additional time on site) is a commercial decision to be made by the gas supplier. For this reason AMO supports the suggestion that gas suppliers be given the option to wait for the electricity installation as any additional installation costs will ultimately be borne by the consumer. The gas supplier may seek to proceed with a smart meter installation in advance of a change to the electricity meter in circumstances such as the desire to charge the customer on a prepayment arrangement. Despite the higher costs, these may be lower than the alternative of a short lived traditional prepayment meter.
14. Do you think there are any other barriers to gas Smart Metering Equipment being installed before electricity Smart Metering Equipment? Please explain your reasoning.	See answer to Q13. In addition, may choose to use a gas meter with its own battery powered WAN unit. This may be designed for x years life, so the battery 'expires' when HAN (and new WAN powered by electricity meter change) is installed subsequently. The framework should allow resolution the business problems in innovative ways.
15. What do you think the implications would be of extending the new and replacement obligations to the licences of other relevant parties in relation to installing Smart Metering Equipment in new developments without	*Yes, see full response in later section of this document*

Question	Response
the involvement of a supplier? Do you think mechanisms other than licence conditions should be considered to achieve the policy objective? Please explain your reasoning.	
16. Do you think the roll-out of Smart Metering Equipment has any specific implications for the provision of emergency metering services? Please explain your reasoning.	*Yes, see full response in later section of this document*
17. What period of notice do you think would be appropriate before the obligation to provide an IHD comes into effect? Please explain your reasoning.	*No comment*
18. Would the consumer changing their supplier raise any particular issues with regard to the approach set out for the provision of IHDs? Please explain your reasoning.	*No comment*
19. Do you think the licence conditions as drafted effectively underpin the policy intentions set out for the provision of IHDs to domestic consumers? Please explain your reasoning.	*No comment*
20. Do you agree that the Standard Licence Conditions identified above require consequential changes in light of the roll-out licence conditions? Do you agree with the Government's proposed approach? Please explain your reasoning.	*No comment*
21. Do you think there are any other consequential changes	*No comment*

Question	Response
to existing licence conditions needed in order to make the proposed roll-out obligations work as intended? Please explain your reasoning.	
22. Do you think there are any consequential changes to existing legislation needed in order to make the proposed roll-out obligations work correctly? Please explain your reasoning.	*See answer to Q15 and full response in later section of this document*
23. Do you think there are any consequential changes to existing codes needed in order to make the proposed roll-out obligations work correctly? Please explain your reasoning.	Inevitably there will be a need to change certain requirements. These should be raised and proceed through the existing code governance change cycle.
24. Do you think that there are other requirements that the Government should adopt in the SMETS? Please explain your reasoning.	The core requirements from the IDTS and the where directly related the Industry supporting documents should form the basis for the SMETS. These will also need to take into account: •Outputs from the Business process work in the DCG & BPDG groups, •Resolution of Communications Hub, Push Pull and security discussions, •Further inputs from industry to ensure the data modelling is more closely aligned with the preferred application protocols to avoid excessive rewriting of protocol standards to fit the GB model •Security algorithms, accreditation etc. need to be considered.
25. Do you agree that all the requirements recommended in the IDTS should be adopted by the Government in the SMETS? Please explain your reasoning.	The mass rollout phase is being squeezed from both ends; at the start through the DCC and HAN protocols not being available until late 2014 and at the end through an ambition to complete the rollout in the "earlier part" of 2019 (as referred to in question 1). This leaves less around 5 years to install circa 50 million domestic smart meters. The Government has estimated that up to 6.5 million smart meters will be installed during the Foundation Phase. AMO believes this to be unrealistic due to many reasons which can be grouped as follows: <u>The delay to knowing what 'compliance' is</u> ▪ The IDTS is excessively complex ▪ The process to develop the IDTS into the SMETS and gain EU approval will last until at least Summer 2012 ▪ The separate Communications Hub (if mandated) will require significant development in order to reach standardisation ▪ The ownership of Communications Hub is not resolved ▪ Some of the functionality and scope of the Communications Hub relies on the DCC service provider input who are not appointed until Q4

Question	Response
	2012 ▪ It is currently unclear what SMS functionality resides in the Communications Hub and what resides in the meters ▪ The HAN standard will not be fully resolved until Q4 2014 ▪ The criteria to adopt meters into the DCC is not known ▪ The DCC WAN technology is not known ▪ New smart meters and Communications Hubs will need to be designed, tested and approved. The approvals process is likely to be a bottle neck ▪ Clear identification of the degree by which the requirement affects each device in the SMS. The architecture supporting document holds a reference for this which now need further assessment with the detailed ESoDR requirements in the IDTS. ▪ Thorough review and alignment of detail with good Technical Authors. The amount of detail in some areas of the IDTS (e.g. pre-payment) alongside some of the outstanding technical areas (e.g. the HAN protocol, DCC structure, application layer protocol, Communications Hub and outage detection) mean there is still a great deal of uncertainty surrounding SMS "compliance." The cost associated with the overly demanding technical specifications and particularly the separate Communications Hub concept will load cost into the development of 'compliant' meters. The target for consumer savings of £22 by 2020 is therefore likely to be reduced. ***AMO believes that DECC should promote a layered approach to the SMETS where the hardware and core functionality are resolved as soon as possible and the more burdensome or unclear functionality be added in later versions of the SMETS and where possible added remotely to the existing smart meter stock. This approach will allow the Foundation Phase to continue and will allow suppliers to gradually build up installation volumes and the smart metering workforce to ensure a smooth and successful start to the mass rollout phase of the Programme.*** Would like to see 80/20 if 80% are defined then agree them now. Meter installation of 'non-smart' meters has effectively stopped. So bringing in a layered approach to enable 'smart' meters to be fitted sooner rather than later.
26. Do you agree that the security requirements recommended in the IDTS are proportionate to the level of risk that the End-to-end Smart Metering System faces? Please explain your reasoning.	The overall security requirements are fine as an ideal, however they are far from specific and do contradict themselves when it comes to the level of security. The recommendation to use FIPS is a good one but not specifying a consistent FIPS level (1 2 and 3 are all mentioned) is not a good idea, in addition based on the makeup of the smart metering environment the actual level required would most likely be 4 which is not mentioned at all. The reasoning behind this is that the meters will be at insecure remote locations with little or no protection from tampering so the full FIPS security standard should apply to allow the maximum protection of the consumer and supplier at all times, Also the remote disconnect functionality and 13 months of stored profile data are other key reasons for this level of security as they are new additions to functionality and although disconnect is available currently the

Question	Response
	wireless connectivity aspect of the SMS is a much bigger risk than existing solutions
27. Do you agree that the process outlined above is a suitable way forward to develop the SMETS? Please explain your reasoning.	*See response to Question 25*
28. Do you think that the SMETS should ultimately be governed as part of the Smart Energy Code? What alternative arrangements could be adopted for the ongoing governance of the SMETS? Please explain your reasoning.	Whoever is financially impacted by SMETS should be involved in the governance to ensure changes are practically and commercially viable. This would include the Suppliers, Network companies, Meter Operators, Meter Asset Providers, Equipment manufacturers. Could be represented by trade associations including AMO & BEAMA. SEC may be an appropriate route. If the layered approach describe in Question 25 above, then the governance arrangements for this enhancement route should be established so changes can be considered, debated and agreed.
29. What unit manufacturing cost reduction do you think can be achieved for Smart Metering Equipment over the next 20 years? Please explain your reasoning. Please also provide any other comments (accompanied by evidence) on the estimated costs of the Smart Metering Equipment as set out in the Impact Assessment.	*No comment*
30. Do you agree that the Government should include a requirement for a Communications Hub in the SMETS? Please explain your reasoning.	Yes AMO supports a requirement for a Communications Hub (i.e. a section of a SMS containing WAN, HAN and some functionality). Meter designers and manufacturers are likely to locate these elements closely together in the meter anyway. AMO believe that suppliers should be able to choose whether to install a SMS with a 'separate' or 'intimate' Communications Hub and this choice (and innovation) should be left to the market to decide hence controlling SMS and installation costs The Communications hub should not be designed in the electricity meter circuit board – otherwise the whole meter would need changing to exchange the communication element. Stranding additional assets and disrupting the customer by having to interrupt the electricity.

Question	Response
	 The use of a modular communications module fitted intimately in a meter housing has been established in the HH and Advanced meter market for many years. As an example, the Elster meter A1700[3] allows for different communications modules to be inserted/replaced without removal of the meter. The smart meter should enable the location of a communications module within the meter casing and the provision of 230V power (live & neutral) – in line with the paper submitted by the AMO to the SMDG/Hothouse and in a subsequent ERA paper, which the AMO support. The communication module could also be fitted into a separate housing which would require power, for example where the electricity meter has not already been installed, or where a gas (or water) meter(s) are fitted distant from the electricity meter. The communications module would rely on HAN radio communications with the electricity meter irrespective of whether it is fitted intimately or remotely. This minimises the technical interoperability issues required to agree low power pin configurations, another communications protocol and ensures 'plug socket' will still be serviceable in a harsh environment after 10-20 years.
31. Do you agree with the estimated costs and benefits for outage detection and the Government proposal to require the Communications Hub to include the equipment necessary to provide electricity outage detection? Please explain your reasoning.	*No comment*
32. Do you agree that the DCC Communication Service Providers should specify the requirements for outage detection as part of their general role in specifying the WAN technology? Please explain your	The electricity network companies gain the benefit of outage and restoration notification. They should justify the cost and benefit. The AMO has no opinion on the best technical solution within the overall smart metering system. Economies may be achieved dependent upon the granularity of outages identified – each meter or selection of meters in a geography.

[3] www.elstermetering.com/downloads/A1700D_brochure.pdf

Question	Response
reasoning	
33. Do you think that the Communications Hub should also have the functionality to send a communication to the DCC when power is restored? Please explain your reasoning.	The electricity network companies gain the benefit of outage and restoration notification. They should justify the cost and benefit. The AMO has no opinion on the best technical solution within the overall smart metering system. Economies may be achieved dependent upon the granularity of outages identified – each meter or selection of meters in a geography.
34. Do you agree with the Government's proposal that fully integrated electricity meters and Communications Hubs will not comply with the SMETS? Please explain your reasoning.	Yes. Taking this approach will minimise stranding of electricity meters, reduce need to interrupt supply to correct communications failures and unnecessary site visits.
35. Do you think the Smart Metering Implementation Programme objectives would be better met by: a. Using the SMETS to mandate a separate Communications Hub with a fixed WAN transceiver? Or b. Giving suppliers flexibility over options for configuration of the Communications Hub? Please explain your reasoning.	The AMO agree with option B - *The Smart Metering Implementation Programme objectives would be better met by: Giving suppliers flexibility over options for configuration of the Communications Hub.* It is has not been established from a meter manufacturing cost or "time on site" perspective that the communications hub is the best solution. Even if this were to be the case the AMO believes that the industry should still have the option to innovate and provide alternative solutions whilst still meeting the overall requirement of modularisation
36. Do you agree there should be no restrictions on the HAN standards adopted by suppliers, provided they are available as a European (CEN, CENELEC or ETSI) or International (IEC or ISO) standard? Please provide evidence to support your position.	Standardising the HAN is essential for all stakeholders in the Programme: ▪ Consumers – A HAN standard will simplify the process of adding smart appliances or advanced IHDs to the household ▪ IHD and meter manufacturers – A HAN standard will give manufacturers some certainty to invest in developing products for the Foundation Phase without risking stranding ▪ Suppliers – A HAN standard will reduce the likelihood of having to re-visit consumers to exchange the Communications Hub ▪ Networks – A HAN standard will allow the development in plans for in home demand response to assist in balancing the network In relation to the Foundation Phase; the risk of asset stranding associated

Question	Response
	with the HAN will discourage Foundation Phase installations. It will also create a 'sheep' effect with everyone installing the market leader so that all stakeholders minimise their risk of being incompatible with other equipment. The Foundation Phase may not therefore lead to any innovation. DECC is understandably reluctant to select a HAN technology. The AMO believes that if a dedicated transport layer for the HAN was established, this would allow manufacturers to build smart metering equipment with components that can handle a range on HAN technologies confident that should the HAN technology they initially deploy not become the enduring industry solution, the HAN on metering systems already installed could be remotely upgraded to another solution. If there is no HAN standard mandated then it would be conceivable that gas meter could be on one standard, IHD and Communications module on others. Interoperability fails, or requires a series of 'bridging devices' which add to cost. Difficult property type may require different solutions.
37. The IDTS has recommended that all standards should be recognised or be in the process of being recognised by 31 December 2014; do you agree with this recommendation? Please explain your reasoning.	Until a standard is chosen and ratified, most likely as a BS-EN directive, then equipment manufacturers cannot implement a final solution. If the enduring HAN standard is not established until the end of 2014 this discourages smart meter installation during the Foundation Phase as these meters may need to be revisited and the Communications Hub exchanged. Agreement sooner would enable installation with confidence about minimising stranding risk.
38. Do you think that regulatory obligations are needed to underpin a systematic approach to testing of HAN standards during the Foundation phase? Please explain your reasoning.	Yes There is little benefit in investing too much time/effort in testing building/premise which are likely to be successful. Effort needs committing to the more challenging HAN environments – distance, foil backed plaster board, metal clad, stone and concrete construction.
39. Do you agree with industry's recommendation that DLMS should be adopted as the application layer for communications with the DCC? Do you believe there is any consumer, economic or technical issues with this solution which could be circumvented by an alternative approach? Do you have any economic, technical or consumer	*No comment*

Question	Response
Government in evaluating industry's proposal?	
40. Do you agree with industry's recommendation that DLMS and Zigbee SEP 1.x should be adopted as the application layer for communications within the consumer premises, provided they install the necessary translation equipment? Do you believe there are any consumer, economic or technical issues with this solution which could be resolved by an alternative approach? Do you have any economic, technical or consumer evidence to assist Government in evaluating industry's proposal?	*No comment*
41. Do you think the Smart Metering Implementation Programme objectives would be best met by the proposed approach above? Or should a single, network-layer technology standard such as IPv6 be mandated? Please explain your reasoning.	*No comment*
42. Is the provision of a single network-layer address for each Communications Hub a reasonable and sufficient functional requirement for the Smart Meter WAN? Will this requirement limit potential future capability or present challenges, for example, in multi-occupancy buildings?	A single network address per hub is all that is required. If multiple meters/customers are available then this would be addressed at the application layer. This could be handled by DLMS if that is the chosen application protocol.
43. Do you think that	This should be achievable at a minimal cost, but the network operator

Question	Response
maximum and minimum demand functionality should be included in the SMETS? Please provide supporting evidence for your response	should specify max and min demand periods as this could potentially impact implementation costs such as additional memory requirements. Not sure what value this brings the network company. Max demand can never exceed the capacity of the service. The combined maximum demand across a series of premises (such as a street) will be diverse so the only way of seeking the street demand over a period is from the HH data.
44. Do you think that network registers should be included in the SMETS? Please provide supporting evidence for your response (including the cost implications for Smart Metering Equipment, and any alternative approaches that would provide this functionality).	Added costs and complication. Layer it in later if justified. *If* settlement moves to HH then there is little further data that could/should be required.
45. Do you think that the prepayment meter contactor switch should be utilised to protect consumer premises from "floating neutral" network faults? Please provide evidence on the costs and benefits to support your reasoning.	No This changes the meter into a safety device which will add to cost/requirements. The metering equipment is installed by the Meter Operator (not distributor) and Meter Operators are subject to ESQCR[4] Reg 3 & 24: *"...3.—(1) Generators, distributors and meter operators shall ensure that their equipment is—* *(a) sufficient for the purposes for and the circumstances in which it is used; and* *(b) so constructed, installed, protected (both electrically and mechanically), used and maintained as to prevent danger, interference with or interruption of supply, so far as is reasonably practicable. ...* *24.- (1) A distributor or meter operator shall ensure that each item of his equipment which is on a consumer's premises but which is not under the control of the consumer (whether forming part of the consumer's installation or not) is—* *(a) suitable for its purpose;* *(b) installed and, so far as is reasonably practicable, maintained so as to prevent danger; ..."* The costs and liability for the design and operation of the metering equipment would now fall to the Meter Operator for provision of a "safety device" to identify and "protect" the customer from one of the many faults potentially customers may incur from the distributors' network transfers substantial unquantifiable risk from distributors to Meter Operators. These risks and liabilities would need identified and quantified prior to acceptance by Meter Operators. The feasibility of a metering device

[4] www.legislation.gov.uk/uksi/2002/2665/contents/made

Question	Response
	identifying and protecting against these incidents has not be proven. The requirements for 'maintaining' would need investigation – would the device need testing to prove satisfactory operation every [x] years?
46. Do you agree with the proposed approach for consumers to access data and transfer it from the HAN via a separate "bridging" device? Please explain your reasoning.	*No comment*
47. Do you have any views on the options presented to ensure that electrical contractors can work safely and efficiently between the electricity meter and the consumer unit/fuse box? Please provide evidence to support your reasoning.	*Yes, see full response in later section of this document*
48. Do you agree with industry's proposals for an overall architecture of an application layer standard with translation through a Communications Hub to a HAN? Do you believe there are any consumer, economic or technical issues	*No comment*
49. Where do you believe that translation is best managed: a. At the Communications Hub; Or b. At the DCC? Do you have any economic, technical or consumer evidence to assist Government in evaluating the options?	*No comment*
50. Do you agree that the IHD should only be required to display ambient feedback based on energy	The minimum specification IHD needs to be simple enough that customers can understand the functions and 'GB plc.' achieves the benefits identified in the DECC Impact Assessment

Question	Response
usage? Please explain your answer.	
51. Do you agree that Smart Metering Equipment should be designed to support the calculation and/or display of account balances as described above, even though suppliers may not initially be mandated to invoke such functionality for credit customers?	*No comment*
52. What do you think the costs and benefits are of mandating suppliers to display an account balance (over-and-above those arising from display of information on cumulative cost of consumption) for credit customers on their IHD?	*No comment*
53. Do you agree with or have any comments on the Government's proposals for the outstanding issues from the Response? Please explain your reasoning.	*No comment*
54. Do you think that an assurance framework, underpinned by regulatory obligations, is needed to support the delivery of the required functionality, interconnectivity, interoperability, and security of Smart Metering Equipment? Please explain your reasoning.	Yes It is essential that the smart metering system operates successfully technically and commercially. See response to Question 10. ***Prevention is better than cure - there should be substantial efforts to ensure interoperability upfront (at design/approval stage) and not adjudicate later. Once meters are installed the costs of rectification (recall/replacement) massively increases whereas the public credibility of the smart meter programme deteriorates.*** It is not apparent the approach is a significant quantity of installed meters are deemed to be 'non-compliant' what happens? Are they removed immediately, delaying the installation of more meters, or are they left towards the end of the roll-out period and then removed? Or will there be a derogation process?
55. Do you agree that as part of any assurance framework adopted, there should be a testing regime in place	Yes Otherwise how else can you be confident of interoperability. MAP funders would seek reassurance from external and independent

Question	Response
to support the delivery of the required functionality, interoperability and security? Please explain your reasoning	testing of the equipment that they are funding. This will reduce their risk of the equipment being deemed to be 'non interoperable' and it value will diminish rapidly. Anything that can remove risk will reduce costs to stakeholders.
56. What are your views on the options outlined for a testing regime? Are there other options that should be considered?	As long as specification is clear and unambiguous then should be clear and therefore testing should be clear. With such a complex specification as the SMETS there will inevitably be ambiguities identified in the initial years. See also response to Question 10 For consumer led equipment, like the IHD and consumer equipment, then certification mark is valuable. "Mandatory industry code and body to deliver and govern a testing regime" is the preferred option, but with the opportunity for evolution as the risks/benefits become better understood.
57. Do you think that a different approach to assurance is necessary for the Foundation and enduring phases? Please explain your answer.	It is hard to see how any assurance regime could be established in time for the foundation stage, but as we have suggested in the response to Question 25 as a layered development of the technical specification. A similar layered approach may be appropriate for the foundation stage.
58. Do you think that the activities outlined above are a suitable way for achieving interoperability across Smart Metering Equipment cryptographic functionality? How else could this be achieved?	*No comment*
59. Do you agree that cryptographic/ key management is necessary to secure the End-to-end Smart Metering System? Please explain your reasoning	*No comment*
60. Do you agree with the Government's assessment of the advantages and disadvantages of the cryptographic solutions identified above? What other options should the Government consider? Please explain your reasoning	*No comment*

Question	Response
61. Do you think that it would be appropriate for the DCC to be responsible for cryptographic key management for the End-to-end Smart Metering System? What other options should the Government consider? Please explain your reasoning.	*No comment*
62. How do you believe the security approach should be applied to opted out non-domestic consumers? Do you see any issues with the approach? Please explain your reasoning.	*No comment*

3. Q1 - Volume of installs

3.1. Key Messages

There will be a number of challenges for stakeholders to recruit, train, retain, and motivate the workforce during the 2012-2020 period, and then to redeploy them at the end of the peak roll-out. The DECC considers further accelerating the speed of the roll-out and the timescale over four years (2014-2018). While all stakeholders wish to see an effective roll-out, the greater challenge of increasing (and subsequently decreasing) the workforce by 3-4 times for a four year roll-out would introduce a further and as yet unquantified risk to the programme. Whilst any risk can be mitigated, the cost to accommodate such an advancement of the roll-out should be determined through DECCs work. It will result in an increase in the costs of meter operative staff, and/or the use of inappropriately trained meter operatives each of which could adversely impact benefits of the smart meter programme.

The AMO members are all competitive companies who will seek to meet their customers' requirements which may result in the bulk of meters being fitted by end of 2018, however we would be more confident once the full skill/training/recruitment analysis is available from EU Skills. While we appreciate DECC are currently reviewing all the smart metering plans we would ask that you consider the workforce deployment risks that the modelling being undertaken by EU Skills and NSAP will be able to quantify.

Meter Operators have serious concern that achieving safe installation of this volume of metering work is not possible in the proposed period.

3.2. Commentary

The target for roll-out should take full account of the workforce modelling currently being constructed by EU Skills and the National Skills Academy for Power (NSAP). The AMO members are participating in providing data to populate the model.

Determining the appropriate deployment profile is a complex balancing process between speed to gain the benefit of smart meters as soon as possible against the challenge of increasing the meter change rate by 3/4 times today's levels. To increase the workforce requires considerable recruitment and training which will increase labour costs and if approached incorrectly could lead to poor quality operatives.

The conventional 'normal' meter change activity is broadly 6% of the total meter population each year. 5% to account for the average 20 year meter life, plus 1% for new installs credit/prepayment changes, meter moves, etc. Although anecdotal indications are that the activity has declined in the last year to the absolute minimum to maintain accurate and legal metering in anticipation of smart metering. Any new 'non-smart' meters will only have maximum life of eight years, which 'strands' the metering asset and the installation charge. This is currently causing a noticeable reduction in workforce and the consequential loss of skilled staff.

A completion date in 2019 (early or late) will lead to a substantial increase in metering installations. Depending on when the smart meter installations commence it could be a considerable increase in activity to three/four times the current level of activity. In addition is the normal work associated new connections, meter moves and a declining (as smart meters population remove the requirement) for credit to prepayment activity.

This significant ramp up of activity brings risks, all of which can be overcome, but the higher the peak activity the greater the risk of increased cost, or delays, or failure from any or all of the following issues.

- Recruitment – to increasing the workforce fourfold for four years with capable staff will bring increased recruitment and staff cost.
- Training – ramping up the training facilities for two/three years and investing training effort (estimated at three months per person per fuel) for four years productive employment. The related assessments for gas & electricity authorisations will increase.
- Staff costs – the above issues will increase meter operative staffing direct and indirect costs by employing staff on a short term basis.

- Logistics & back office support – behind each meter operative is a support infrastructure ranging from HR, procurement of tools and equipment, quality assurance checks, meter storage, meter returns/disposal, etc. All of these will need to be ramped up for the peak of activity, and will need to be subsequently redeployed as the activity declines.
- Safety, revenue protection & data issues – for each meter change there are a percentage that are a problem. Increasing the meter change rate by fourfold will consequently increase the problems identified. The supporting roles will also need to have increased resources to address:
    - safety issues (problems with cut-out or ECV at customers' installation)
    - investigation of potential illegal extraction (interference with the metering equipment), and
    - erroneous data from previously (or newly created) incorrect metering arrangements (e.g. crossed meters).

  If any of these issues are not addressed fully then unsafe situations may remain, illegal actions may not be investigated or customer dissatisfaction continue due to erroneous information/billing resolution.
- Electricity/gas distribution network remedial issues - will be identified that require network operators to resolve. Electricity & gas network operators will need to ensure they have the resources in place to meet such demands and consumers' expectations.
- Residual staffing – after the roll out there will be a low level of meter installation work. The remaining work will be fault fixing and new connections (about 1% year, but very dependent on new house construction). Fault fixing will depend on the actual life/reliability of all the components within the smart metering system. Existing credit/prepayment meter changes will cease.
- Equipment failures - Most electronic equipment follows a 'bath tub' reliability curve, so the equipment may suffer early failures, which will require revisits to replace. If problems occur at a peak of activity the ability of the supply chain to identify the problem, resolve it, and replenish stock may result in many meter installations being delayed, and trained staff being underutilised.

Although Meter Operators will resolve each of these issues, the overall effect will be a higher cost for the faster the roll-out to support the peak of activity. In a commercial environment all parties will seek to minimise the impact of these issues although they cannot be removed completely.

We recognise that DECC and suppliers may see benefits to a faster roll-out but the risks and increased costs need to be considered within the overall risk analysis. From the Meter Operator perspective the *optimum* roll-out has a much smoother and longer timescale, ideally a smooth ramp up and ramp down, but with an even profile over at least five years.

4. Q15 & Q22 - Network operator licence conditions

4.1. Background

Ofgem issued several open letters in 2010 on this aspect, seeking views from the industry on the “Review of Current Metering Arrangements”.[5]

4.2. Key messages

There is no doubt that competition in metering services progressively introduced since 1994 has driven down the cost of metering services, increased the quality of service and led to innovative solutions to the benefit of all utility customers.

The AMO members are supportive of a competitive environment, therefore wish to see the removal of all remaining metering obligations on gas transporters. Ideally earlier, but at the latest, these legacy obligations should be removed at the time that the requirement for all new and replacement meters to be smart meters is applied to energy suppliers.

Meters should not be installed without the involvement of the supplier and/or end user customer. Gas and electricity network companies should not be able to install new metering equipment.

Competition in metering services has not developed as well as it should have done over the last few years due to two issues causing uncertainty:

- the indecision of any smart metering obligations, and
- uncertainty over the competition issues in the gas metering sector.

There is no evidence that the removal of the ‘last resort’ obligations from electricity Distributors from 2007 has had any detrimental effect on electricity customers.

4.3. Commentary

The AMO members are supportive of a competitive environment, therefore wish to see the removal of all remaining metering obligations on gas transporters. Ideally earlier, but at the latest, these legacy obligations should be removed at the time that the requirement for all new and replacement meters to be smart meters is applied to energy suppliers.

The remaining gas transporter last resort obligations have price caps which are said to under charge prepayment metering services. This is believed to result in prepayment metering being provided under the ‘last resort’ provision and credit metering under a competitive regime. This artificially distorts both the last resort activity and the commercial metering services.

It has been reported that only a limited number of meters are being fitted under the remaining ‘last resort’ obligations on gas transporters. If this is the case, then removing the obligations should not be too disruptive to the market.

There is no evidence that the removal of the ‘last resort’ obligations from electricity Distributors in 2007 has had any detrimental effect on electricity customers, or energy suppliers. It did cause some disturbance to the market as suppliers had to actively procure new competitive service providers, although they did have two years notice of the intended changes.

A lesson from the electricity changes in 2007 is that there should always be clear separation/transparency of metering charges (both MAP & Meter Operator) and use of system charges. The metering charges should not be bundled with use of system charges and presented as a single charge.

In the electricity model there is clear separation between MAP & MOP with an acceptance that different companies can act in the different roles over the life of the metering asset. This concept has not been accepted by all participants in gas metering provision, meaning that certain participants are only willing to

[5] www.ofgem.gov.uk/Markets/sm/metering/tftm/roma/Pages/roma.aspx

operate a combined Meter Operator/MAP activity. The different approach needs challenging to understand if there is are justifiable reasons for maintaining a combined activity.

Members have reported some difficulties in successfully providing competitive metering services on iGT networks. A particular issue for suppliers and Meter Operators has been the ability to provide prepayment or smart meters on iGT networks. This is an aspect that members believe should be included in DECCs further investigations.

Members are still concerned about the significant numbers of meters which are exchanged under the PEMS arrangements. The commercial drivers of network companies and Meter Operators are different which may be leading to meters (or components of the metering system) being changed unnecessarily. Provision of a PEMS service under a smart meter environment will become extremely burdensome for Transporters and the other stakeholders. Equally the current obligation on suppliers to provide a three to four hour service where prepayment metering has failed, will effectively apply to all 'domestic sized' meters, removing one of the key drivers for PEMS.

There is a need to revisit the current obligations of the 'gas act owner' to ensure the obligations on the supplier and gas transporter are made appropriately. For example, where the meter was provided by the gas transporter, going forward the supplier needs to take on the obligation of ensuring that the meter is accurate for customer billing. It is understood that some suppliers have not supported the gas transporter to ensure gas transported provided meters are changed in a timely manner. Clarity of responsibility for accuracy of metering should rest upon a single party, the supplier, who then has the ability (through powers in the Gas act) to influence a meter change with their customer.

5. Q16 - UMETS & PEMS under smart

5.1. Purpose

The DECC consultation[6] document: "Consultation on draft licence conditions and technical specifications for the rollout of gas and electricity smart metering equipment " highlights the implications for emergency metering services, seeking responses under Question 16: *Do you think the roll-out of Smart Metering Equipment has any specific implications for the provision of emergency metering services? Please explain your reasoning.*

This section seeks to respond to this specific question.

5.2. Objective

In considering this issue the Members of the AMO are keen to ensure that the established and future arrangements meet the following objectives:

- minimise the disruption to domestic customers from the resolution of meter faults; and
- the costs of meter services are kept as low as reasonably practical; and
- competition in metering services is not undermined.

The history and current practices between gas and electricity differ substantially. This is an opportunity to let the requirements converge.

5.3. Background

The Post Emergency Metering Service (PEMS) was introduced to the industry by Ofgem at the time of wider gas metering competition. It was perceived as an interim requirement prior to metering competition developing a market led solution. Contracts were created by National Grid (and successor gas Distribution Networks) and the service has been operational since July 2004. Over the last five years 662,261 of 5.8 million emergency visits have resulted in a chargeable PEMS job, 11.5% of uncontrolled gas emergency calls. In five years, 173,000 meters have been changed under PEMS, the reminder are smaller parts of the metering system being changed. It is understood that not all suppliers signed up to the PEMS service over the full period that the service has existed. The PEMS activity is estimated to have cost the industry over £25m over the last five years.

UMETS was discussed at the time of wider electricity metering competition in 2001. A number of DNOs declined to provide an emergency service. The number of incidents relevant to a "UMETS type" service is believed to be very low, or non-existent.

The justification for the existence of PEMS (and UMETS) provided by the network company is that once an emergency operative is at site then it is only marginal extra time for them to resolve problems associated with metering equipment. And the customer experience is better if the operative can resolve all the problems in the one visit. The price controlled charges for gas emergency call outs includes a fixed level of time at site and materials up to a value of (£4.65 index linked). This is intended to investigate and fix simple tasks, like tightening a nut; whether this be on the metering equipment of the customers equipment. An underlying assumption is that the operative attending the emergency call is trained, and equipped, to replace metering equipment - this is increasingly not always the case.

Ofgem issued an open letter on 12 Oct 2007 seeking views on the "Gas Post-Emergency Metering Services" document 244/07[7]. Responses were published, although no changes in requirements resulted.

The term Meter Operator is used throughout this document to include both the gas metering term Meter Asset Manager (MAM) and the electricity term Meter Operator.

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6 www.decc.gov.uk/en/content/cms/consultations/cons_smip/cons_smip.aspx

7 www.ofgem.gov.uk/Markets/RetMkts/Metrng/Comp/Gas/Documents1/open%20letter%20and%20guidelines.pdf

5.4. Commentary

5.4.1. Level of UMETs activity

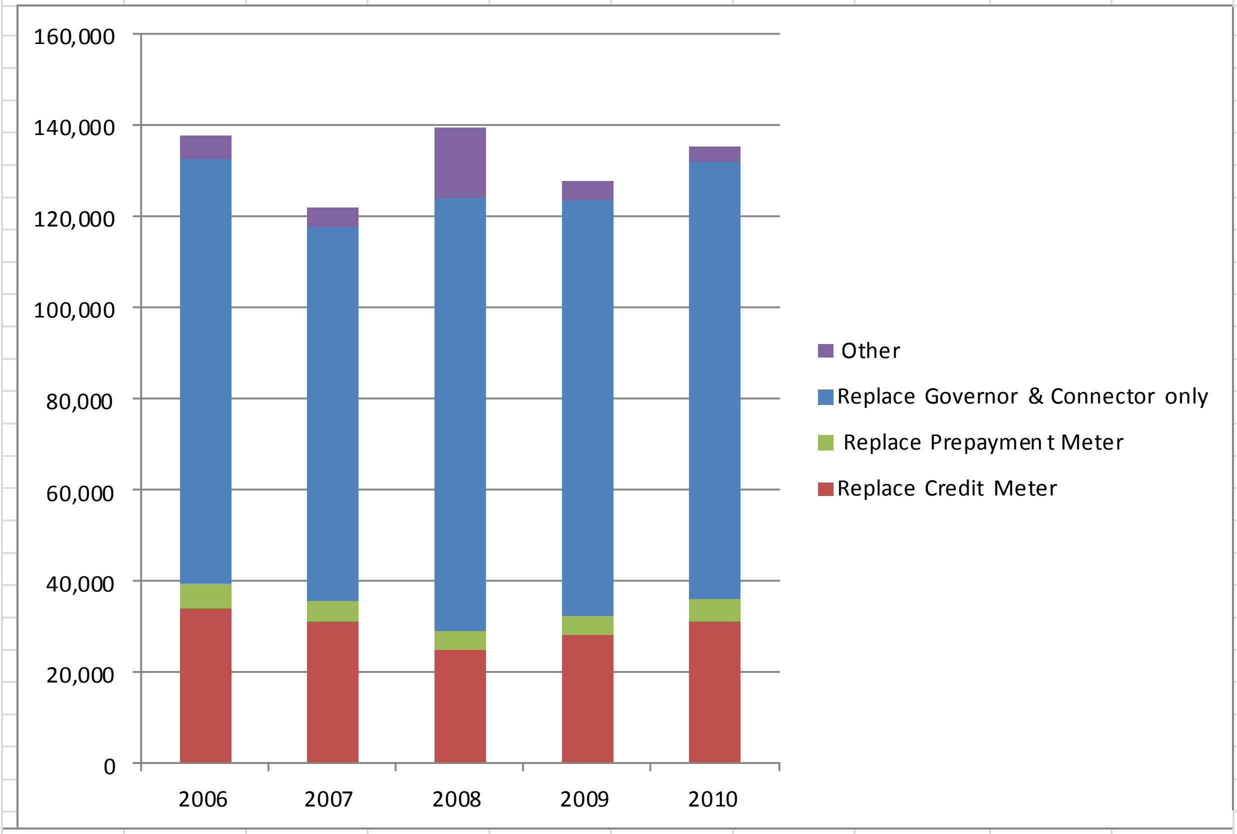
UMETs was discussed at the time of wider electricity metering competition. A number of DNOs declined to provide an emergency service. The number of incidents relevant to faulty electricity metering equipment is believed to be very low, or non-existent. There are few, if any incidents associated the technical failure of the electrical metering equipment. Failures of electricity distribution business equipment, e.g. cut-out fuse failure, fire in the premises; are dealt with under the price controlled revenue by a distribution business emergency representative attending the premises. In the few circumstances where the problem is purely associated with the metering equipment then the distributor will 'make safe' until the Meter Operator can attend. Where the problem is resulting from problems on the customer's electrical installation, the distribution representative would 'make safe' until the customers' electrician has attended to resolve the issue.

Discussion on the arrangements have taken place in recent years in DCUSA working groups. No mandated service from Distributors has resulted. Suppliers and Distributors are free to negotiate an unregulated service if they wish.

5.4.2. Level of PEMS activity

As a result of the 2007 Ofgem consultation the AMO has requested Ofgem to seek the actual level of activity associated with PEMS. Ofgem has issued a number of information requests, and the companies have allowed the responses to be published. The AMO has reviewed this information and summarised it. The figures are shown in the appendix, with an annual summary shown below.

Numbers of Activities per calendar year	Replace Governor & Connector only	Replace Credit Meter	Replace Prepayment Meter	Other	PEMS total	Emergency call outs	Call outs resulting in PEMS	Call outs resulting in meter change
2006	93,132	34,064	5,548	5,080	137,824	1,170,174	11.8%	3.4%
2007	82,044	31,068	4,695	4,036	121,843	1,146,164	10.6%	3.1%
2008	95,079	24,671	4,520	15,294	139,564	1,101,164	12.7%	2.7%
2009	91,052	28,056	4,447	4,092	127,647	1,197,333	10.7%	2.7%
2010	95,885	31,211	5,057	3,230	135,383	1,181,870	11.5%	3.1%
five year total	457,192	149,070	24,267	31,732	662,261	5,796,706	11.4%	3.0%



The figures show that around 11.5% of emergency uncontrolled gas escape call-outs result in a chargeable “PEMS activity”. If meter equipment is really causing 10% of all emergency calls then it raises’ serious concerns about the design, installation, meter operative competency or long term suitability of the metering activity.

The AMO members are concerned that this high level is not reflective of the true position of the metering equipment quality.

Some corrective work should be performed within the limits set out in Gas Transporter standard licence condition 6, i.e. within the 30 min. allocated on site and small material cost (£4.65 index linked). For the avoidance of doubt, this price controlled corrective work would not be referred back to the Supplier/Meter Operator or appear in the PEMS numbers above.

5.4.3. Operational concerns in current PEMS process

A significant concern in the current PEMS arrangements is that the incumbent Meter Operator may not receive sufficient information to identify problems and learn the lessons from faulty installations. Where there is an issue associated with the metering installation the emergency service operative will fix the fault so even where the incumbent Meter Operator subsequently attends site they would not be able to investigate the original situation.

If the fault was caused by poor practice by the meter operative the incumbent Meter Operator does not have the ability to inspect the original installation. This will limit the opportunity for the incumbent Meter Operator to identify specific further training requirements for operatives, or in serious cases, to initiate disciplinary action.

It is important that faulty equipment is quickly returned to the Meter Operator, suitably identified with customer & reason for removal. If it is within manufacturer warranty period the Meter Operator may be able to return it to the manufacturer for investigation and compensation. A manufacturer has indicated that very few meters are returned under warranty. If the equipment is changed because of customer damage (as opposed to faulty equipment) the damage could be identified and charged to the supplier/customer, with the Meter Operator keeping the damaged equipment as evidence. The network operator staff do not have a financial incentive to differentiate between fault and customer damage, and would normally err on the side of caution (when at site) to retain good customer relations and for personal safety.

If the meter is changed by the incumbent Meter Operator, then they can use normal business processes to communicate meter readings and new meter details to the energy supplier and MAP(s), without relying on a third party (the network operator staff).

The incumbent Meter Operator has no influence over the replacement metering asset (manufacturer/model) used by the network operator. The network operator may use different meter types which have shorter useful lives and different warranties. In some circumstances the network operator may replace a prepayment meter with a credit meter resulting the Supplier & Meter Operator having to arrange further visits to reinstate a prepayment meter, with which the customer may not be co-operative.

If the PEMS continues then it is important that robust information can flow in a timely manner to ensure that Meter Operators are able to properly identify and manage the performance of the metering assets.

5.4.4. Cost Incentives

Under current PEMS the costs of a PEMS activity is charged as follows:

- The network operator to the Supplier (through Supplier/network operator PEMS contract)

  The network operator indicates they have performed a PEMS activity, this is charged to the relevant supplier at the month end.

- The Supplier to the Meter Operator (through Supplier/Meter Operator services contract)

  The Supplier identifies the relevant Meter Operator for each PEMS activity, then prepares an invoice for that Meter Operator to recover the PEMS costs. The PEMS costs include the cost of the replacement meter together with the effort (time) for the replacement.

Therefore the Supplier acts as a ‘middle man’ apart from administrative effort, is simply passing on the costs it has received from the network operator to the Meter Operator. The Supplier has contracted with the Meter Operator to maintain a working meter and *believes* that the network operator will only have performed necessary work. Clearly, the reliability of assets is a key driver of cost of meter provision and Meter Operators take significant risk on this basis so it is essential that they are assured that no unnecessary costs are incurred.

If the Meter Operator can find sufficient evidence (e.g. a hole in a meter) then they can seek recompense from the Meter Asset Provider (MAP) or under warranty from an equipment manufacturer. Although as indicated above, if the equipment can not be recovered this fails, leaving the Meter Operator incurring the whole cost.

When they are not directly exposed to the costs, there is no particular incentive for the Supplier to keep the network operator costs low or to be involved with resolving the weaknesses in the current PEMS process.

An appropriate incentive would be to only pay the network operator for PEMS work upon delivery to the Meter Operator of:

- All replaced equipment (meters, regulators, flexible tubes, etc.)
- All associated meter technical details (meter readings, serial numbers, etc.)

5.5. Smart environment

A smart environment will add further issues for the network operator to provide a PEMS/UMETS type service over and above today's operational environment.

Meter types – The Suppliers have previously resisted the network operators fitting credit meters to replace a prepayment meter. Some customers can become extremely difficult about providing access to fit a replacement prepayment meter. In the same way, it would not be appropriate to replace a smart meter with a 'dumb' credit meter.

People skills - As currently drafted the Smart Metering Installation Code of Practice only applies to the initial smart meter installation, and the first few months thereafter. Therefore PEMS/UMETS activity will not be in scope of the SMICoP, therefore the training, competency requirements will be determined through normal business routes. Although the smart requirements will require to be able to safely install a replacement meter there will be the need to ensure the new smart meter can communicate with the HAN/WAN, this will be a new skill set for the emergency response operatives.

Process & security - The new meter serial number will be required to be recognised by the Data Communications Company (DCC) as a valid meter prior to allowing communication with DCC. The meter will require configuration using a Hand Held Terminal (HHT). The HHT will require regular communication with DCC to ensure it continues to be appropriately authorised. Where WAN communications are not operational the HHT will need prior details of *all* the relevant Suppliers' meter configuration rules (credit limits, rules about times when can/will not interrupt supply, etc.). The removed meter must be properly decommissioned from DCC to prevent recall/fault reporting activities.

These activities will increase the complexity and therefore the cost of offering a PEMS/UMETS activity. This will swing the balance further in favour of calling out the incumbent Meter Operator who will have the staff, equipment and processes immediately available to resolve these issues.

5.6. Customer disruption/alternative model

PEMS was introduced to minimise the disruption to domestic customers where gas leaks associated with metering equipment could delay the restoration of gas supply. This objective is perfectly reasonable. Meter Operators already attend meter problems and prepayment meters faults under Guaranteed Standards as non-emergency contractual obligations.

The Gas (Standards of Performance) Regulations 2005 (SI No. 1135)[8], put obligations on Suppliers to ensure that a domestic customer that has a problem with their *prepayment* meters (see regulation 5) should be resolved within 4 hours from reporting to the supplier during the hours of 8.00 am to 8.00 pm on each working day and 9.00am to 5.00pm on any other day. For reports outside these hours the clock starts at beginning of the following day. Another SI applies to electricit y pre-payment meters with slightly different timescales. These obligations are being strengthened by the Ofgem/DECC 'spring package' licence conditions to ensure that all smart meters are regarded as *prepayment meters* for these purposes. Therefore all smart meter operational problems should be attended to within 3 to 4 hours during the daytime 365 days/year.

These "Guaranteed Standards" have had a long evolution based on a balance between the costs of provision of this service compared with the alternative higher costs of staff on call 24 hours/day, 7 days a week. This balance has evolved fully recognising that customers with prepayment meters are often the more vulnerable in society. The result is a framework where meter problems are not resolved instantly, but within a specified number of hours, dependent upon the day and time of the week (365 days/year) of when the issue is reported.

It is proposed that a similar approach should be acceptable for all smart metering faults. If the emergency network operator person arriving on site, determining that the fault is associated with metering equipment

[8] www.legislation.gov.uk/uksi/2005/1135/regulation/5/made

and *can not be resolved within 30mins* (and materials (£4.65 index linked), makes safe by isolating the ECV and notifies the Supplier/Meter Operator. The Meter Operator would attend within the same timescales for all domestic and small business customers as the Guaranteed Standard regulation 5. All Meter Operators have staff available to respond to the Guaranteed Standards for existing prepayment customer calls and could therefore achieve the same timescales for all meter faults which require the gas to be isolated due to a metering fault.

The Meter Operator would *not* increase their current stand-by costs by having to have staff on call 24 hours, but would respond to more calls to correct prepayment meter issues *and* repair leaking meters. Overall the costs to the industry may reduce dependent upon the numbers of *true* meter faults identified, and the benefits that the Meter Operator would achieve from correcting the flaws identified in section 5.4.3.

Contractual arrangements between Suppliers and Meter Operators can deliver the above framework through normal commercial negotiation. This approach would deliver a 'competitive' solution to minimising customer disruption, whilst limiting costs to the industry, and therefore customers.

If a Meter Operator is called to a 'metering' problem to find that the fault was elsewhere, then the cost of the unnecessary visit would be reflected back through the supplier to the network operator. This would provide the correct financial incentive on the network operator to ensure only valid metering problems were reported for Meter Operator resolution.

The above approach may require two visits in some scenarios, although the overall number of visits would be expected to reduce as unnecessary visits are avoided. This will reduce the overall cost to the industry, and therefore customers.

5.7. True Costs of Metering Services

To make a meaningful comparison between the network operator providing a PEMS service and competitive Meter Operator providing a service then all the costs of the metering service need to be truly allocated to the PEMS charges. The network operator needs to allocate all the costs associated with providing a metering service such as: metering equipment stock control, Meter Operator registration, staff training, management training, vehicle size, financial control, etc. All the risk of service provision need to be recovered through a PEMS charge, probably a fixed charge and a transactional charge.

If the allocation of costs are incorrect between the emergency service and the metering activities of a network operator then the all customers (whether their supplier benefits from it or not) will be paying for the PEMS activity through their regulated use of system charges.

There is a concern that PEMS charges from a network operator may 'cap' the charges a competitive Meter Operator could charge for visiting premises in these emergency situations. To enable a competitive arrangement to evolve the PEMS charges need to be sufficiently high to enable a competitive solution to be a cheaper and more attractive solution.

5.8. Going forward

The provision of an emergency metering service should be on a competitively negotiated model between the Supplier and the Meter Operator, operating within the existing Guaranteed Standards provisions.

If network operators were to continue provision of an emergency metering service, then payment should be on a 'payment on delivery' of a returned asset to the Meter Operator/MAP.

5.9. PEMS statistics – by company over 5 years

Numbers of Activities per calendar year		Replace Governor & Connector only	Replace Credit Meter	Replace Prepayment Meter	other	PEMS total	Emergency call outs	Call outs resulting in PEMS	PEMS Change by Company
2006	NGG	47.789	17,820	2.988	2.708	71,305	566.764	12 6%	
	W&W	14,156	4,282	560	712	19,710	118,772	16.6%	
	Northern GN	9951	3,812	516	n a	14,279	144, 232	9 9%	
	eolia.Scotian	4,029	2,433	484	508	7,454	124,233	60%	
	Scotia·south	17,207	5,717	1,000	1,152	25,076	216,172	11.6%	
	total	93,132	34 064	5,548	5 080	137,824	1,170174	11 8%	
proport1on otact1"ty		76%	28%	5%	4%				
meter type replacements			86%	14%					
2007	NGG	44,270	17,262	2.750	2,174	66,456	560, 335	119%	-7%
	W&W	11 304	4 185	460	651	16 600	114 714	14.5%	-16%
	Northern GN	10,659	3,052	499	nla	14.210	152 796	9 3%	0%
	eolia·Scotian	2,659	1,983	327	376	5,345	113 723	4.7%	-28%
	Scotia·south	13,152	4,586	659	835	19,232	204, 596	9.4%	-23%
	total	82,044	31,068	4,695	4,036	121,843	1,146 164	10.6%	
prop ort1on otact1'·tY		67%	25%	4%	3%				
meter type replacements			87%	13%					
20061 2007 changE		-12%	-9%	-15%	-21%	-12%	-2%		
2008	NGG	53,176	9,254	2,378	12,762	77,570	554, 373	14 0%	17%
	W&W	13,047	3,860	662	595	18,164	110, 308	16 5%	9%
	Northern GN	10,525	3,050	482	n a	14,057	122,235	115%	-1 %
	Scotia- Scotian	4,992	2,900	357	753	9,002	113,949	7.9%	68%
	Scotia- south	13,339	5,607	641	1,184	20,771	200 ,299	104%	8%
	total	95,079	24 ,671	4,520	15.294	139,564	1,101 164	12 7%	
proportion of actl'·tY		78%	20%	4%	13%				
meter type replacements			85%	15%					
20071 2008 changE		16%	-21%	-4%	279%	15%	-4%		
2009	NGG	35 ,365	12,186	2.236	1,431	51 218	666 ,841	77%	-34%
	W&W	16,914	4,354	770	371	22,409	108,686	20 6%	23%
	Northern GN	8,043	1.929	208	776	10,956	117 806	93%	-22%
	eolia- Scotian	5,168	3 060	438	558	9,224	107, 256	8 6%	2%
	Scotia- south	25,562	6,527	795	956	33,840	196 ,744	17.2%	63%
	total	91 ,052	28,056	4,447	4,092	127,647	1,197 ,333	10.7%	
prop ort1on ota ct1"ty		75%	23%	4%	3%				
meter type replacements			86%	14%					
2008 1 2009 changE		-4%	14%	-2%	-73%	-9%	9%		
2010	NGG	41 ,006	14,970	2,916	1,349	60,241	635 ,206	9 5%	18%
	W&W	17 252	4,626	679	273	22.830	113 ,009	20.2%	2%
	Northern GN	8,010	1,987	151	802	10,950	130 ,357	8.4%	0%
	Scotia- Scotian	5,998	3,336	515	366	10,215	109 839	9 3%	11%
	Scotia- south	23.619	6 292	796	440	31,147	193.460	16 1%	-8%
	total	95,885	31,211	5,057	3,230	135,383	1,181 ,870	11.5%	
proportion ofactl'·tY		79%	26%	4%	3%				
meter type replacements			86%	14%					
2009 1 2010 changE		5%	11%	14%	-21%	6%	-1%		

cest/activity	£ 40	£ 60	£ 190	£ 30	Total
2006	£ 3.725,280	£ 1 362,560	£ 221 ,920	£ 203 200	£ 5,512 ,960
2007	£ 3,281,760	£ 1,242,720	£ 187,800	£ 161,440	£ 4,873.720
2008	£ 3,803,160	£ 986,840	£ 180,800	£ 611.760	£ 5,582.560
2009	£ 3,642,080	£ 1,122 ,240	£ 177,880	£ 163,680	£ 5,105 ,880
2010	£ 3,835.400	£ 1 248.440	£ 202 ,280	£ 129 200	£ 5.415 ,320

Notes

Som e acti..,ty cla ss1ficat1on mayd1ffer between companies
Replactng meters, mayalso tndude replactng regulators
In some cases number of emerg encycalls has been reverse calculated
Charges are an est1mate to g1ve a financial s1gn1ficance
Some publis hed numbers and publls hed totals, sllghtly d1ffer
Ofgem 2008 tnfo request http 1w ww ofaemoov ui<'Paaes/Mxelnf orrmtion aspx?docid 188&ref er Marketslsm'rmtenndcr f cqwetltiorl aas
Ofgem 2011 1nfo request http 1/w ww ofoomoov ui<'Paaes/Mxelnf orrmtlon aspx?docld=194&refer=Markets sm'rmtenng'crflcqwetltlonlaas

6. Q47 - Isolator Switch

6.1. Background

The tails between the metering equipment and the customers termination equipment (consumer units, switch fuses, etc.) are the property of the customer. These tails are connected to the metering equipment under a terminal cover which is sealed by the Meter Operator, the Meter Operator is the only industry role with authority to break these seals and makes these connections. For traceability, the seals are uniquely identifiable to the employing company and individual meter operative. The seals are required for three reasons:

- Safety – limit the opportunity for exposure to danger, as required in ESQCR Reg 24[9]
- Revenue protection – industry codes require access to potentially 'unmetered' electricity to be restricted to limit the opportunity for theft of electricity
- Traceability – if there are concerns about some part of the metering installation, the operative can be traced, many years after the work.

Meter have been produced in the past, which are still in service, which include an isolation switch. This is specifically for use by a trained electricians. The terminal cover on the meter is split, the live (unmetered) side is sealed by the Meter Operator as normal, the outgoing side is sealed with a plastic seal and labelled to warn that it should only be removed by a competent electrician.

The image shows a meter with the outgoing terminal cover removed revealing the switch and cable termination screws.

6.2. New meter installations

In most new meter installations the meter operator is currently fitting the metering equipment and terminating the work into a separate double pole isolation (DPI) switch. The provision and fitting off this switch is costed into the work, chargeable to the supplier/customer. The installation is done this way to enable the electrician and the Meter Operator to complete their respective work without being time dependent on each other.

9 www.legislation.gov.uk/uksi/2002/2665/regulation/24/made

6.3. Exchange of meter

At some meter exchange visits problems are identified with the customers installation, including:

- Poor or inadequate customer electrical termination equipment
- Incorrect size meter tails
- Potentially loose terminals in the customers termination equipment

Option 1 - In the most extreme cases the Meter Operator is required to not reconnect the customers equipment and remove the cut-out fuse, leaving the customer de-energised. This would require the customer to arrange for an electrician to attend and take corrective action, then arrange for the Meter Operator to re-visit the premises to re-energise. This may take some days, over which period the customer is without an electricity supply.

Option 2 - In the same circumstances, some Meter Operators take the approach of fitting a DPI, and not reconnecting the customers equipment. In this case the supply remains energised up to the DPI. The customer will arrange for an electrician to attend and take corrective action. The electrician can connect directly into the outgoing terminals of the DPI and restore supply to the customer's premises.

Option 2 has the benefit that the speed of restoration of supply is totally within the control of the customer and their electrician, whereas Option1 requires the customer to arrange with the Supplier and their Meter Operator to revisit the premises to re-energise. Option 2 requires the Supplier/Meter Operator to fund the provision of a DPI. Whereas Option 2 provides a better customer experience due to the speed for restoring supply.

6.4. Electrician work

If an electrician visits a premises to work on the customers termination equipment then they will often need to isolate the supply to the customers termination equipment. The official method[10] of achieving this is by contacting the relevant Supplier and arranging for the Meter Operator to attend. Electricians dislike this approach because:

- They cannot always get the Suppliers' call centre to understand their request
- Meter Operators are generally not available to visit *instantly* – visit requires scheduling and therefore forward planning by electrician
- There may be a cost for the visit and/or cost of providing a DPI

As a result, some electricians will take a less safe and illegal approach of either breaking the cut-out and/or meter terminal cover seal and changing the meter tails on the outgoing side of the meter. This may be done live or after removal of the cut-out fuse carrier. Alternatively they may cut and terminate the existing meter tails into a connector block, whilst they are still live.

Working live is not a safe method of work. Breaking seals leaves the customer exposed to potential legal action for illegal extraction (theft) of electricity. Breaking the seal on the cut-out can break the sealing 'loops', making the cut-out impossible to re-seal, which may require replacement of the cut-out.

The numbers of requests to attend for a temporary de-energisation, or fit a DPI, so an electrician can work on the customers equipment safely and legally are believed to be low. Although finding the numbers has always been difficult. In 2009 a DCUSA working group spent a year considering the best approach, the outcomes included better information (hence the guidance document[11]), mandate the fitting of a DPI as part of all meter work and consideration of inclusion of switch within a smart meter.

In a future the 'loss of supply' notification will inform industry parties when the metering system loses supply, this will highlight circumstances where the cut-out fuse is removed without permission. And may reduce the circumstances where the electrician removes the cut-out fuse, significantly increasing the numbers following the correct approach.

[10] www.dcusa.co.uk/Public/ViewDocument.aspx?id=2303
[11] www.dcusa.co.uk/Public/ViewDocument.aspx?id=2303

This image shows where the consumer had been changed by taking the tails from the meter into a new pair of connector blocks. This work was performed live, as there is no evidence of the seals being broken. The old tails are cut off, visible just above the meter. The new tails have been brought through a new hole cut through above the timeswitch (hence the brick dust by the cut-out).

Working live is against The Electricity at Work Regulations 1989, Reg 14[12] unless there is no alternative. For the simple reason that it puts the operative at greater risk of injury or death.

6.5. Going forward

The industry can continue as currently, although the number of visits to attend for temporary de-energisation can be expected to increase, and the population of separate DPIs will also increase. The Electrical Safety Council (ESC) have advised DECC of the scale of consumer unit changes per annum. These costs will fall back to customers in charges for visits and provision of separate DPIs.

Alternatively provision of an isolation switch can be included in the smart meter design. Although the cost of a smart meter will increase, the benefit of reduction in additional visits and provision of separate DPIs will reduce.

Our discussion with the HSE has included debate about whether single or double pole switch is required. Although the double pole may be ideal, the use of this facility is by competent staff who can be expected to remove both tails achieving double pole isolation. The current practice of de-energisation of removing the cut-out fuse is only single pole isolation.

The smart meter will have a switch to achieve interruption of supply. It may be possible to utilise this switch by allowing some mechanic interlock to prevent unexpected closure.

We are aware that DECC have been continuing investigation into this subject during the consultation phase. We would welcome the opportunity to discuss DECC's investigations and the assumptions in any underlying cost/benefit model, together with other industry stakeholders. It is difficult to capture all of the nuances of a complex debate in a brief consultation response.

[12] www.legislation.gov.uk/uksi/1989/635/regulation/14/made