

DCUSA DCP 158 Consultation Responses – Collated Comments

Question 1	Do you understand the intent of DCP 158?	Working Group Comments
British Gas	Yes	Noted.
Electricity North West	Yes. The intent is to put billing arrangements in place for private networks where difference metering exists.	Noted.
Elxon	Yes. The supporting documents clearly explains the intent of DCP 158.	Noted.
Forth Ports	Yes	Noted.
GDF Suez	Yes	Noted.
Northern Powergrid	Yes	Noted.
NPower	Yes. The intent of DCP158 is to standardise the LDNO charging arrangements at Complex Sites where Difference Metering is being applied. Such Complex Sites are covered in BSCP514 8.4.3 under the “Difference Metering Option”.	Noted.
Peel Ports	Yes	Noted.
Southern Electric Power Distribution & Scottish Hydro	Yes	Noted.

Electric Power Distribution		
SP Distribution & SP Manweb	Yes	Noted.
SSE Energy Supply Ltd	Yes	Noted.
UK Power Networks	Yes	Noted.
Western Power Distribution	Yes	Noted.
Question 2	Do you agree with the principles of DCP 158?	Working Group Comments
British Gas	<p>We do not agree with the principle of a gross boundary data solution where difference metering is used for an mpan within a private network.</p> <p>Suppliers should only be reasonably expected to pay transportation costs for energy they are responsible for. It is not clear to us why DNOs should consider it valid or appropriate to expect suppliers to pay for the transportation of energy for which they are not responsible.</p> <p>We favour a net metering solution with minimal impacts on industry processes and systems. We provide details of such a solution in our response to question 22.</p>	Noted and see our response to question 22.

Electricity North West	Yes, we agree that a common approach to billing the customers within these networks as well as the network owner through the boundary meter would be helpful for all parties.	Noted.
Elexon	Yes. A standardised approach for DUoS charging is required and it is important to implement while the current volume of Third Party MPAN currently low.	Noted.
Forth Ports	Yes	Noted.
GDF Suez	Yes	Noted.
Northern Powergrid	Yes	Noted.
NPower	Yes	Noted.
Peel Ports	Yes	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	Yes	Noted.
SP Distribution & SP Manweb	Yes	Noted.
SSE Energy	Yes	Noted.

Supply Ltd		
UK Power Networks	Yes	Noted.
Western Power Distribution	Yes	Noted.
Question 3	Do you believe that you are or may be affected by competition in supply on private networks?	Working Group Comments
Electricity North West	Yes, we are affected in that the current industry processes mean that the true value of the Import or Export Capacity and reactive consumption is unknown at the boundary of connection with our network as a consequence of difference metering.	Noted.
Elxon	N/A	Noted.
Forth Ports	We operate private networks	Noted.
GDF Suez	Yes, currently as a “third party” supplier, and potentially as a “boundary supplier”.	Noted.
Northern Powergrid	Yes, we have private networks in Northern Powergrid’s two licenced areas where end users may seek to take advantage of the competitive supply market.	Noted.
NPower	Yes. We have already been affected both as a supplier to Licence Exempt Distribution Networks where Difference Metering is being applied and providing a third party supply to sites that are embedded on Licence Exempt Distribution Networks.	Noted.
Peel Ports	Yes, we operate a private network	Noted.

Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	Yes there are a number of private networks of significant scale in our DNO areas	Noted.
SP Distribution & SP Manweb	Yes	Noted.
SSE Energy Supply Ltd	Yes	Noted.
UK Power Networks	Yes	Noted.
Western Power Distribution	Yes	Noted.
Question 4	Do you have a clear preference for the Solution 1, as formally proposed in DCP 158 (billing at the boundary) and if so why?	Working Group Comments
British Gas	No, we do not support an approach that bills based on boundary data. We do not believe that a boundary supplier should be charged for the transportation of energy which it is not responsible for. The supplier is also	Noted and please see our response to question 22.

	<p>unlikely to be able to validate the DUoS invoices it has received, which will lead to increased disputes. Also, as highlighted by the consultation, there will be significant system and/or process costs to implement any of the proposed boundary solutions. Such costs are inappropriate for what is a relatively small and contained issue.</p> <p>A simpler solution with minimal impact on industry systems and processes would for the licensed network operator to charge their standard DUoS rates to both the supplier of the boundary mpan and the supplier(s) of any embedded mpan(s) based on the normal (net metering) settlement data for both (noting that the applicable DUoS tariff may be different for the two depending on the final voltage of connection). The private network operator could recover any necessary Embedded Use of System costs for relevant mpans (calculated in accordance with their approved methodology) from the licensed DNO, who in turn could treat such costs as a pass-through cost. Further detail is provided in response to Q22.</p>	
Electricity North West	No	Noted.
Elxon	<p>As the BSCCo, we do not express clear preference in any of the solutions. However we believe that any changes must be both proportionate and flexible. We are aware of only a handful of sites with Third Party MPANs but recognise the volume could grow significantly.</p> <p>On that basis, we believe Solution 1 could represent less complexities for affected parties.</p>	Noted.
Forth Ports	Yes, it is the cleanest solution	Noted.
GDF Suez	Yes, this is our current preference. It is the solution currently in place in the third party access situation we currently supply and is a pragmatically simple solution,	Noted and please see our response to question 22.

	as we receive only one use of system bill (from the Private Network Operator) for the embedded customer, which incorporates both the DUoS (to the boundary) and “PNUoS” (from the boundary to the customer) charges. This solution does however have limitations from a customer perspective (see 22 below).	
Northern Powergrid	Yes, Northern Powergrid strongly prefers Solution 1 as we believe billing at the boundary as proposed under this solution maintains the clarity of the relationships between the DNO, the PNO directly connected to the DNO and the supplier of the PNO at the boundary with the DNO.	Noted.
NPower	<p>Yes.</p> <p>We believe Solution 1 proposes that all DUoS, Capacity and Reactive charges are billed to the Boundary Point MPAN based on the <u>gross</u> energy flowing through the Boundary Point meter. LDNO charges to any embedded MPANs will be <u>zero rated</u>.</p> <p>This is the approach that we have agreed with two LDNOs at sites that we supply where Difference Metering is being applied.</p> <p>This is a common sense approach as the connection agreement is between the LDNO and the Boundary Point MPAN connected to its network. The DNO does not have such a relationship with embedded MPANs which sit downstream of the Boundary Point. It should be down to the LEDNO as to how it manages the commercial arrangements with sites that are connected to its network. Part of this will include the recovery of costs that the LEDNO incurs for being connected to the LDNO’s network through the Boundary Point meter.</p> <p>This solution also maintains the status quo for the LDNO in terms of what it recovers through its charging methodology. Difference Metering is a requirement under the BSC which ensures that the Active Energy flows feeding into Balancing and Settlements for the Boundary Point MPAN and any embedded MPANs are accurate. LDNOs should not be impacted by this set up in terms of what it recovers through its charging to the Boundary Point MPAN based on the gross energy flows.</p>	Noted.
Peel Ports	Yes. Most cost effective and efficient to continue to pass all the DNO charges on	Noted.

	to the PNO at the boundary where the PNO has to have an approved charging methodology by Ofgem to pass through their costs to the customer fairly and proportionately. Since we have to do this anyway there is no added process or complexity other than the aggregation of capacity by the DA/DC which is the most basic of changes in comparison to the alternatives proposed.	
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	Yes In our view the DNOs responsibilities clearly begin and end at the electrical boundary with the customer and this clarity of boundary should be maintained. Billing at the boundary is a logical extension of this principle.	Noted.
SP Distribution & SP Manweb	Yes – this solution results in the DNO issuing 1 invoice with the correct exceeded capacity and kVArh being billed regardless of the number of customers on a private network requesting a MPAN. There is no requirement for a separate monthly, quarterly or yearly reconciliation charge for exceeded capacity and kVArh. DNO is also not charging DUOS to a customer that is not connected to their network	Noted.
SSE Energy Supply Ltd	Yes. As Supplier we see this as a cleaner approach to DUoS billing Suppliers, allowing these pass through charges to the end Customer total transparent.	Noted.
UK Power Networks	Yes. Solution 1 would support the fully correct charging of tariffs in accordance with CDCM/EDCM in respect of the DNO's connection.	Noted.
Western	Yes – we do not anticipate significant functionality changes to existing billing	Noted.

	<p>site fully settled.</p> <ol style="list-style-type: none"> 2. A supplier would need to understand what they will receive from the private network operator regarding the Licensed Distributor charges up to the boundary for their embedded customers. This is out with DCUSA and is likely to be subject to differing terms across private network operators. 3. Notwithstanding the above how does the private network operator obtain the meter readings/HH advances of the embedded customers so that they can bill the appropriate supplier? 4. How do they know who the embedded supplier is? 5. How will they know there has been a change of supplier so they bill the correct supplier and apportion the consumption to each? 6. Whilst it is understood that the private network operator will have terms to be agreed between the supplier and themselves over their network usage costs (and these are common to both solutions) it is unknown whether the terms for usage up to the boundary are similar to those terms offered by the licensed distributor or not e.g. will there be an administration charge, what are the payment terms? <p>In summary there probably needs to be a bi-lateral agreement in place on similar lines to DCUSA section 2A.</p>	<p>change but the outcome of the step change is the same.</p> <ol style="list-style-type: none"> 2. Noted. 3. Noted. Access to the data would be by agreement between the PNO and the Suppliers/DCs and applies for both solutions. 4. Not relevant to the option chosen but also they would know who the embedded Supplier is via the agreement with the PNO. 5. See response to answer 4. 6. See response to answer 4. In summary: Agreed and evidence suggests that is currently the case.
Elexon	As above	Noted.
Forth Ports	This is a clumsy solution, requiring additional billing streams and annual reconciliation of capacity and reactive power. This reconciliation is a major issue for Private Networks as the third party supplier may have changed over this period	Noted.

	and/or the customer may well have left the network. This would leave the private network with a bill, but no method to recoup it. Further as part of the billing goes to the customer and part to the private network, this just appears to make work for all parties, whereas under solution 1 the billing all goes to the private network, who is already dividing its costs up and billing any third party supplier via the Ofgem approved methodology for its use of system billing anyway. This just adds another invoicing process and scope for additional confusion.	
GDF Suez	No. This solution would lead to an added administrative burden because two charges (one for DUoS and one for PNUoS) would have to be passed through to the customer, and it would not remove the difficulties in having to pass through PNUoS.	Noted.
Northern Powergrid	No, we prefer Solution 1 to Solution 2, as outlined in question 4 above.	Noted.
NPower	<p>No.</p> <p>We would question the validity of LDNOs charging for sites that are embedded on a private network and not directly connected to the Distribution Network. There is no connection agreement between the LDNO and the embedded end user.</p> <p>LDNOs relationship is with the connection to their network at the Boundary Point meter, and they should not be concerned with embedded sites that sit downstream of the Boundary Point meter. The fact that a Settlements meter (MPAN) has been installed at an embedded site does not change the operating dynamics of the private network. It should be down to the private network operator as to how they manage their network and any connections to it.</p> <p>Solution 2 would also result in the LDNOs having to raise multiple invoices, one for</p>	Noted.

	the Boundary Point MPAN and one for each MPAN embedded on the private network. We favour Solution 1 which does not increase the number of invoices that have to be raised by the LDNOs or validated by Suppliers.	
Peel Ports	<p>No. Will add further processes, cost and further complexity. More added processes = more opportunity for error. Likely to result in potential disputes and liability for reconciliation of capacity usage after the event, for exceeded capacity or reactive power when tenant may not even be in residence after the event. Could result in embedded customer claiming ownership of capacity and trying to agree/ benefit from a variation in capacity which has been paid for (reinforcement) by the Private Network operator.</p> <p>This solution causes complications if the take up is small or large for third party access. Higher risk than reward – only reward is visibility for the customer of the DNO charges which could be attained via the charging methodology if this is the only driver for this preference.</p>	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	No	Noted.
SP Distribution & SP	No – this solution requires 2 separate invoices from the DNO to the boundary supplier for the same settlement period. (1 to invoice the Units, Fixed and capacity and 1 to reconcile the capacity charge and also correctly invoice the kVArh). This	Noted. Agree that there would be system impacts if e-billing could and was used. Changes to

Manweb	could be problematic as the reconciliation charge will potentially be issued on a yearly basis and both boundary and end customers could have changed suppliers during this period. It also requires a separate DUOS invoice to the supplier(s) of all the embedded customers in the PN, who are not customers directly connected to the DNO's network. This will potentially lead to multiple DUOS invoices being sent to the end customers. We agree with the DCP consultation in that there is a potential safety issue with this solution. DCP 142 will also impact on this solution as explained in the answer to question 14.	the CDCM would be required to facilitate this i.e. billing format would change.
SSE Energy Supply Ltd	No (as confirmed by SSE during the meeting). As Supplier to potential Customers within the Private Network, we see ourselves receiving two sets of DUoS charges, one from the LNDO, and where the Private Network Operator has submitted a charging methodology, one from them.	Noted.
UK Power Networks	No It is not appropriate to disaggregate capacity charges related to the boundary to apply to embedded premises in that A) the licenced distributor is not responsible for the agreed capacities of embedded premises, B) changes to capacities between the private network operator and the embedded customer is a matter for those two parties, C) the exceeded capacity charge in respect of embedded premises or indeed the rump billed capacity charge for the boundary would be fairly arbitrary according to the chosen division of the boundary's capacity charge.	Noted.
Western Power Distribution	No.	Noted.

Question 6	Are you undecided at this stage in terms of your preferred solution and if so why?	Working Group Comments
British Gas	We provide details of our preferred solution in response to question 22.	Noted.
Electricity North West	Not on the solution but potentially on the options within each solution dependent upon volume of embedded customers.	Noted.
Elexon	N/A	Noted.
Forth Ports	N/A	Noted.
GDF Suez	N/A	Noted.
Northern Powergrid	No.	Noted.
NPower	N/A	Noted.
Peel Ports	No	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	No	Noted.
SP Distribution	No – our clear preference is Solution 1	Noted.

& SP Manweb		
SSE Energy Supply Ltd	No	Noted.
UK Power Networks	No	Noted.
Western Power Distribution	No.	Noted.
Question 7	Under any of the solutions do you believe there are any changes required under schedule 16, 17 and 18 of the DCUSA?	Working Group Comments
British Gas	Solution 2 would appear to require new CDCM tariffs (for embedded mpans). Solution 1 may require references to D0275/D0036 to be updated. Any annual reconciliation of capacity and reactive charges would also need to be incorporated into the methodologies.	Noted.
Electricity North West	Yes. Solution 1 There may need to be a zero tariff for Licensed distributor MPANs within private networks. Solution 2 We would have to create new tariffs and since existing tariff arrangements are captured with schedule 16 we would need to add new ones for the embedded customers e.g. no capacity and reactive charges being applied.	Noted.

Elxon	N/A	Noted.
Forth Ports	N/A	Noted.
GDF Suez	No comment	Noted.
Northern Powergrid	<p>Yes, there is the possibility that changes to both the common distribution charging methodology (CDCM) and the extra high voltage distribution charging methodology (EDCM) models would be required if new or discounted tariffs were needed as part of the implementation of Solution 2.</p> <p>Furthermore, Solution 2 introduces additional complexity (in the form of more tariffs) into the market, but, in feedback from our stakeholders, it is clear that they prefer simplicity and transparency so adding more discounted tariffs is not desirable.</p>	Noted.
NPower	<p>It needs to be clear that under proposed Solution 1 that all LDNO DUoS, Reactive and Capacity charges will be charged to the Boundary Point MPAN based on the gross energy flowing onto the private network through the Boundary Point meter. All such charges to embedded MPANs that sit downstream of the Boundary Point meter should be zero rated. The term “gross energy” needs defining so that it is understood that this is consistent with the Boundary Point metered data before any complex mapping has been applied.</p> <p>We currently have no comment with regards to Solution 2. The required changes under Solution 2 to any of the schedules should be explored dependent on the outcome of this consultation.</p>	Noted.
Peel Ports	Don't know	Noted.
Southern Electric	We do not believe any significant changes are required to CDCM & EDCM Methodologies set out in schedules 16,17 & 18. However, it is helpful to clarify the	Noted.

Power Distribution & Scottish Hydro Electric Power Distribution	application of the DUoS charges for such private networks connected to the DNO's distribution system either in the schedules and/or in the DNO's LC14 Use of System Charging Statement.	
SP Distribution & SP Manweb	No changes have been identified to schedule 16, 17 and 18 in relation to the three suggested solutions within this change proposal.	Noted.
SSE Energy Supply Ltd	Yes	Noted.
UK Power Networks	Yes – see proposal	Noted.
Western Power Distribution	Yes	Noted.
Question 8 A.	While there are potentially very many sites that are covered by the new market facility it is unclear how many customers on such sites may strike contract with Suppliers, in so doing initiate the Difference Metering billing solution necessitating new arrangements to maintain or support DUOS billing by the LDNO.	Working Group Comments

	In your view which solution is most appropriate if the take up is small?	
British Gas	See response to Q22 for our proposed solution.	Noted and please see our response to question 22.
Electricity North West	<p>Solution 2 – bill on data received and potentially ignore any excess capacity charges and reactive charges.</p> <p>The distributor will be recovering the agreed capacity for the boundary through their charges.</p> <p>The private network owner is unlikely to want to run the network in excess of the network capacity since it would mean all their customers could potentially lose supply. This approach is no different to the relationship with other distributors i.e. an agreed capacity for the boundary point and, in most instances; the boundary points don't have a boundary meter in any case.</p> <p>Regarding reactive income, the value in our region when compared to total use of system income is in the region of 0.3%. When you then consider the number of private networks and then the number of customers likely to move within private networks (and presently we don't seem to have any) it can be argued that the impact will be very negligible on smaller volumes so it makes sense to just bill on the data received but for embedded customers' suppliers you don't bill capacity (which should be charged at the boundary) and reactive charges until the volumes increase significantly.</p>	Noted.
Elxon	N/A	Noted.
Forth Ports	Either Option 2 or 4 – no firm preference	Noted.
GDF Suez	Option 1	Noted.
Northern	Solution 1 - Option 2 has the least impact to both current resources and system	The Working Group agreed that

Powergrid	<p>changes hence is most appropriate if the volume of customers taking up the new market facility is small.</p> <p>However, consideration needs to be given to what the level of uptake needs to be in order to trigger the introduction of a more enduring solution. The working group needs to consider if they are proposing a two step solution that changes dependent on the level of uptake or a single proposal that can be adopted straight away and refined at a later date, via a new change proposal, if the level of uptake increases?</p> <p>It may be beneficial to undertake a request for information exercise which attempts to quantify the potential number of sites that may take up the new market facility.</p>	<p>a two-step process was not appropriate. The Working group are seeking to introduce a single solution which could be amended at a later date if required.</p>
NPower	<p>We believe Option 4 of Solution 1 is the most appropriate if the take up is small. Additionally, where there is a large take up on a private network where Difference Metering is already being applied, this approach would not cause any additional workload. The Boundary Point gross energy data would already be being sent by the HHDC to the LDNO and the Supplier to the Boundary Point MPAN.</p> <p>This approach will require the HHDC to send the gross energy data for the Boundary Point MPAN, to the LDNO and the Supplier to the Boundary Point MPAN. This gross energy data is already available to the HHDC as it is effectively the metered data it collects prior to applying the complex mapping. It is assumed that the spreadsheet will be sent by email at the start of a month (first Business Day) and contain HH data for the whole of the previous month. The LDNO and Supplier should be able to manually create the D0036/D0275 flow from this data for loading into their DUoS billing or DUoS validation system.</p> <p>This new market facility was introduced on 9th November 2011 through the</p>	<p>Noted.</p>

	<p>Electricity and Gas (Internal Markets) Regulations 2011. Since that date we have set up third party supply arrangements at just two sites which are embedded on private networks. Option 4 of Solution 1 is effectively the approach that we have adopted to facilitate DUoS billing and validation for sites where Difference Metering is being applied. As a Supplier we have simply 'tagged' the Boundary Point MPAN in our DUoS validation system and load in the D0275 flow that is manually created from the gross data provided by the HHDC. In future we may look to using an MTC of 996 that identifies Boundary Point MPANs where Difference Metering is being applied on the private network as an automatic 'tag'.</p> <p>It should be noted that there is currently no requirement under DCUSA or the BSC for the HHDC to send to the LDNO and Supplier the gross energy data for the Boundary Point MPAN where Difference Metering is being applied on the private network.</p>	<p>Noted that NPower chooses to use this option.</p> <p>Noted that this CP is looking to introduce a requirement under the DCUSA.</p>
Peel Ports	<p>Solution 1: Option 2 would be the preferred with Option 4 a possibility if very low uptake and agreement of the common parties to the process e.g. DA/DC and MOP.</p> <p>Does not require expensive changes to the various Industry processes and data flows and can be managed as current complex sites are managed on a site by site basis.</p>	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric	Solution 1 option 4	Noted.

Power Distribution		
SP Distribution & SP Manweb	Solution 1 Option 2 or Option 4. Both options will only work if take up is small. The requirement for the DC to issue a spreadsheet will be manually intensive if numbers rise and also care would be required to ensure this process continued on change of DC. Option 2 would require monitoring for change of agent to provide pseudo MPAN details to new supplier and DC – how would this be controlled? We are currently adopting Solution 1 Option 4 but after consideration we now believe Solution 1 Option 2 is the preferred solution if the volume is low.	Noted. The BSC would be blind to the pseudo MPAN so there would a requirement under the DCUSA to send the data using the pseudo MPAN and the distributor would be required to notify the party of the pseudo MPAN.
SSE Energy Supply Ltd	If the numbers remain small, then the current manual 'work around' can meet the requirements. (SSE confirmed at the meeting that this was solution 1 option) 4.	Noted.
UK Power Networks	Solution 1 We do not believe solution 2 is appropriate at all as per comments above.	Noted.
Western Power Distribution	Solution 1	Noted.
8B.	In your view which solution is most appropriate if the take up is large or very large?	Working Group Comments
British Gas	See response to Q22 for our proposed solution.	Noted and please see our response to question 22.
Electricity North West	Solution 2 because at some point fully settled sites will start to exist and they are billed on the embedded MPAN data and not at boundary MPAN data.	Noted. Fully settled is outside of the scope of this CP.
Elxon	N/A	Noted.

Forth Ports	Option 3	Noted.
GDF Suez	Option 3	Noted.
Northern Powergrid	<p>We believe that Solution 1 - Option 3 would be most appropriate if the volume of customers taking up the new market facility is large. There would be a higher cost associated to make this happen through system changes and potential additional resources being required, but it would result in a robust and enduring solution rather than a low cost option as detailed in option 2.</p> <p>We believe that, in addition to our contribution to the industry costs incurred from the introduction of new data flows, our individual internal costs to be in the region of £50K to £70K, based on the previous implementation of changes to our systems to accommodate new data flows for IDNO billing.</p>	Noted.
NPower	<p>The take up since this market facility was introduced on 9th November 2011 has been very small. Only one of our customers has requested this facility in order to for Npower to provide a third party supply to two sites which are embedded on private networks. However, it is difficult to gauge the rate or level of future take up which may result in a large number of embedded sites receiving a third party supply.</p> <p>We believe Option 3 of Solution 1 offers the most robust and enduring approach should take up reach such a level where the manual costs associated with operating Option 4 of Solution 1 have increased to the point where it becomes viable to incur the costs associated with creating the new data flows and necessary system changes in order to automate the process.</p>	Noted.
Peel Ports	Solution 1 option 3 or full settlement metering where appropriate.	Noted.

Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	At this time the likelihood of a large or very large take up in this area is minimal. It is difficult to justify a business case for I.T development of any solution until volumes dictate that is necessary.	Noted.
SP Distribution & SP Manweb	Solution 1 Option 3. This option becomes more cost effective and robust if a large volume of customers request MPANS on private networks	Noted.
SSE Energy Supply Ltd	Solution 1 using additional automated DTC flows	Noted.
UK Power Networks	Solution 1 We do not believe solution 2 is appropriate at all as per comments above.	Noted.
Western Power Distribution	Solution 1	Noted.
8C.	Does your option change depending on volume?	Working Group Comments
British Gas	See response to Q22 for our proposed solution.	Noted and please see our response to question 22.
Electricity North West	Our interpretation of small and large was based on volume so this question is	Noted.

	already catered for above.	
Elxon	N/A	Noted.
Forth Ports	Option 3 is preferable, but it is clearly not cost effective unless this market grows beyond the current number of relevant customers.	Noted.
GDF Suez	As above, yes.	Noted.
Northern Powergrid	Yes. See response to previous questions.	Noted.
NPower	See our response to question 8 (b).	Noted.
Peel Ports	<p>Somewhat between the Solution 1 options and Full Settlement Metering but not for Solution 2.</p> <p>On the practicality and feasibility of the solution – if full settlement metering is a realistic option (all customers would want independent supply) without significant commercial reconfiguration of metering and networks this should be the preferred approach.</p> <p>Where this is not possible Solution 1 option 3 gives a sensible and enduring solution for a high volume take up.</p> <p>Solution 1 option 2 is a half way house with medium cost and added complexity but reliance on the various parties DA/DC following the processes set out consistently and reliably.</p>	Noted.
Southern Electric	This would be driven by an impact analysis once volumes dictate.	Noted.

Power Distribution & Scottish Hydro Electric Power Distribution		
SP Distribution & SP Manweb	Yes – SPD currently utilises Solution 1 Option 4 to bill DUOS however as stated in Section A Option 2 would be our preferred option for low volume. However, if the volume became very large then option 3 would become more cost effective and would be the preferred option	Noted.
SSE Energy Supply Ltd	Yes	Noted.
UK Power Networks	No	Noted.
Western Power Distribution	No	Noted.
Question 9	What are the potential costs of each option? Which option for your organisation would have the highest or lowest cost?	Working Group Comments
British Gas	We believe all proposed solutions in the consultation incur unacceptably high system or process costs for what is a relatively small and contained issue.	Noted.
Electricity North West	It is too early to determine this and it also depends on the solution since we believe that the options apply to either solution.	Noted.

	<p>However to add in some value, if it was solution two with minimal volumes resulting in a decision not to undertake reconciliation on excess capacity and reactive charges then there is likely to be minimal ongoing costs apart from initial set up costs associated with MDD changes for new LLFs and a change in process to handle address updates. At some point there would need to be a process change based on volumes to receive gross boundary data and bill using such data for excess capacity and reactive charges.</p> <p>If the decision is to receive such gross data by data flow (be it on either solution) this would be a significant change to stop billing based on D0036/D0275 in preference of the new data flow where a boundary MPAN has embedded MPANs.</p>						
Elxon	N/A				Noted.		
Forth Ports	Solution 2 creates the largest cost for private networks, it also creates the largest liability.				Noted.		
GDF Suez	Solution 2 would have a higher cost than Solution 1.				Noted.		
Northern Powergrid	Proposal		Shared Industry costs	Potential DNO costs	Comments	Noted.	
	Solution 1	Option 1	No	Circa £10k			Manual process and DNO resourcing issue
		Option 2	No	Circa £10k			Manual process and DNO resourcing issue
		Option 3	Yes	Circa £50 - 70k			New data flows; system changes; and

					On-going resourcing	
	Option 4	No	Circa £10k		Manual process and DNO resourcing issue	
	Solution 2	Yes	Circa £50 - 70k		New data flows or manual process; DNO resourcing issue; and New tariffs needed	
NPower	<p>With reference to our response to 8 (b), we believe that the cost of each option is dependent on the level of uptake.</p> <p>We currently have in manual process in place to obtain the gross data and validate the DUoS invoice for the Boundary Point MPAN where Difference Metering is being applied i.e. Option 4 of Solution 1. Based on the costs of that manual process increasing in line with the level of take up, then we may realistically expect that for >20 Boundary Points MPANs where Difference Metering is being applied it would become viable to incur the system costs associated with Option 3 of Solution 1 and automate the process.</p> <p>We would not expect Option 3 of Solution 1 to require extensive system changes. Whilst the option introduces new data flows, these will have the same format as the D0036/D0275 which DUoS billing and validation systems are already set up for. System changes should just require being able to identify a Boundary Point MPAN where Difference Metering is being applied, and substituting the D0036/D0275 with the new data flow.</p>					Noted.
Peel Ports	<p>The highest cost/risk would be Solution 2 as the PNO would have to add in a financing and risk cost which would be related to the duration of the risk of exceeded capacity and reactive power costs due to post dated reconciliation.</p>					Noted.

	<p>Creates the maximum potential for dispute and confusion as the customer receives multiple bills from each of the parties based on different fundamental charging methodologies with potentially conflicting contractual liabilities for connection/ energisation.</p> <p>The next highest cost would be Solution 1 option 4 due to the manual intervention and validation required.</p>	
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	Based on current volumes solution 1 option 4 would carry the lowest cost.	Noted.
SP Distribution & SP Manweb	<p>Solution 1 – Option 1 – approx set up cost to billing system £40k.</p> <p>Solution 1 – Option 2 - approx set up cost to billing system £8k and minimal ongoing cost.</p> <p>Solution 1 – Option 3 - approx set up cost to billing system £24k.</p> <p>Solution 1 – Option 4 - approx set up cost to billing system £16k and minimal ongoing cost.</p> <p>Solution 2 – Estimated costs £8k, however not enough detail has been provided to produce a realistic estimate for the reconciliation element of this solution.</p>	Noted.
SSE Energy Supply Ltd	Using additional automated DTC flows would attract the highest costs due to necessary system changes	Noted.

UK Power Networks	<p>Costs for us</p> <p>Option 1 = admin costs of summing, system costs in relating mpans of more than one supplier to the billing account of the relevant boundary supplier.</p> <p>Option 2 = no cost other than MPAN creation</p> <p>Option 3 = one-off billing system changes to recognise and handle new flow</p> <p>Option 4 = admin costs of processing the data (don't understand the suggestion that there is no pre-processing as the consumption will have to be priced)</p>	Noted.
Western Power Distribution	The potential costs for each solution are similar and likely to be <£10k.	Noted.
Question 10	Do you believe that there are any issues with using a D0036¹ or D0275 quoting a pseudo MPAN over the Data Transfer Network?	Working Group Comments
British Gas	We would be concerned about the potential negative impact on the integrity of Settlements associated with sending D0036's over the DTN for pseudo mpans when the energy associated with that pseudo mpan has already been included in settlements via a different mpan. We also have concerns with the sending of D0275s for pseudo mpans over the DTN – which is likely to make it more difficult for DNOs reconcile their data to 'genuine' settlement data.	Refer to the Elexon comment below and it is recognised that robust controls need to be put in place between the LDNO and the Supplier.
Electricity North West	Yes, this is the least preferred option since it creates processes external to the industry agreed processes with the resultant issues of updating suppliers and their data collectors on change of supplier, change of agent and the move to fully	Noted. The intent of this CP is to create a common approach and new processes which will

¹ Please refer to section 5 and option 2 and 3 in section 7

	<p>settled needing to be considered notwithstanding the issues of pseudo MPANs sitting outside of settlements or inadvertently entering settlements.</p> <p>We would also have to change the system to cater for the concept of pseudo MPANs since at present any generation of an MPAN triggers an update to MPRS where in this instance it would not be the case.</p>	<p>be agreed by the industry. The Working Group agreed that the generation of MPANs by all distributors does not necessarily trigger an update to MPAS i.e. depends on individual LDNO's systems or processes.</p>
Elexon	As long as recipients are aware of the pseudo MPANs, this should not cause any issues	Noted.
Forth Ports	N/A	
GDF Suez	If there is significant take up of third party access, using pseudo-MPANs does not seem to be an enduring solution. Also it does not appear to add much extra to the simple Option 1.	Noted.
Northern Powergrid	<p>No, we do not believe that there are any issues with using either a D0036 or D0275 flow which quotes a pseudo MPAN over the Data Transfer Network. We feel that as long as the pseudo MPAN is prefixed with either 15 or 23 then the existing data flow we receive will be validated without any issues. The only difference will be in reconciling with MPAS but with the introduction of this change proposal a valid reason will have been established.</p> <p>We would expect suppliers to provide information on sites. The use of MTC 996 will determine a complex site, but will require a lot of manual mapping to associate the individual MPANs within the site.</p>	Noted.
NPower	We do not favour Option 2 of Solution 1 which includes the use of a pseudo MPAN as we believe it will add an unnecessary level of complexity, which may impact accuracy in Balancing and Settlement. There is also the additional cost associated	Noted.

	<p>with creating and managing these pseudo MPANs.</p> <p>We believe Option 3 of Solution 1 will provide a robust and enduring approach if we expect to see an increasing level of uptake.</p>	
Peel Ports	<p>Don't know. There is always the potential for error in all processes if the processes are not routine and 'fool proofed' in hard coded process and regulatory change as per Option 3.</p> <p>However, this should be manageable if there is a validation process (Option 2 and Option 4) and there are a small number of such sites/ customers within a site.</p>	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	The biggest issue for this solution are the development costs associated with using dataflows with pseudo MPANs. This would require system development and currently the business benefit for doing this is unclear.	Noted.
SP Distribution & SP Manweb	Unsure, will rely on advice from parties that have more expertise in this matter	Noted.
SSE Energy Supply Ltd	No	Noted.
UK Power	No	Noted.

Networks	Concerns have been expressed regarding the use of “settlement day” in the D0036 because the data being sent in the flow will not be used in settlement. We do not see this as a show-stopper as the data is still in respect of a settlement day (or a day) regardless of how it will be used.	
Western Power Distribution	No, we’ve done this before and the DTN doesn’t validate the MPAN.	Noted.
Question 11	Do you believe there are any issues in the use of MTC² to identify a Difference Metered boundary point?	Working Group Comments
Electricity North West	We believe that it makes sense to identify such instances whether this be via the MTC or by adding a field within MPRS. The bigger issue is the relationship between the boundary MPAN and the embedded MPANs on the same site. This needs to be made available to the distributor as part of the difference metering process within the relevant BSCP.	Noted. The distributor will be able to put a process in place to identify the relationship through the address fields. Adding the field within MPAS is covered in the next question. If an amendment to the BSCP is required any party/Elexon can raise this change accordingly.
Elexon	Using the MTC can be a quick win in identifying boundary point MPANs and we are not aware of potential issues in using this	Noted.
Forth Ports	This appears a sensible option	Noted.

² Please refer to section 8

GDF Suez	Although this consultation has focussed purely on options open to HH customers, there may be issues if NHH sites wish to have third party access arrangements as the MTC field is needed for NHH MPANs.	Noted. NHH is outside of the scope of this change.
Northern Powergrid	We have identified no issues in using an MTC of 996 as long as this field becomes mandatory in the relevant flows (ensuring all parties apply the new rules consistently), as discussed in the working group, to identify a difference metered boundary point. Consideration needs to be given to allow DNOs to set up combinations in MDD.	Noted. It is the responsibility of LDNOs to ensure that they have appropriate MDD entities in place to facilitate this process.
NPower	No. Embedded MPANs that sit on private networks where Difference Metering is being applied are already required through the Metering Dispensation process to have an MTC of 997. It seems appropriate that the Boundary Point MPAN where Difference Metering is being applied should also be identified with a unique MTC of 996.	Noted.
Peel Ports	Little knowledge of the technical data flows and information but appears from the working group discussions to be a low cost and sensible solution – again for small volume uptake.	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power	No	Noted.

Distribution		
SP Distribution & SP Manweb	No	Noted.
SSE Energy Supply Ltd	No	Noted.
UK Power Networks	No	Noted.
Western Power Distribution	No, providing the supplier provides the correct MTC.	Noted.
Question 12	Do you believe there are any issues in using the first line of the MPAN address³ to identify a particular Difference Metered boundary point with its associated embedded MPANs e.g. such as site name?	Working Group Comments
British Gas	We have concerns that this process is likely to be subject to user error.	Noted.
Electricity North West	The only issue is one of any manual process has an accuracy risk but it does provide for some form of link that at present is not there.	Noted.
Elexon	While there are no issues in using this, it will only be useful if a standardised approach is used for all sites.	Noted.
Forth Ports	This appears a sensible option	Noted.

³ Please refer to section 8

GDF Suez	Pragmatic solution but obviously vulnerable to inconsistency of inputs and difficult to identify as a separate data item for analytical purposes.	Potential change to BSCP 514 and 502 to create a common format e.g. PNO ref at (in the address field). The address may include a code as an identifier.
Northern Powergrid	<p>No, we do not have any issues with using the first line of the MPAN address to identify a particular Difference Metered boundary point with its associated embedded MPANs.</p> <p>We feel consideration should be given to making this field mandatory and defining the required content so that it could be used to provide a link with a pseudo MPAN.</p>	Noted. Please see point above.
NPower	<p>There may be issues with systems being able to identify the MPANs based on the first line of the MPAN address.</p> <p>We believe that the Boundary Point MPANs where Difference Metering is being applied should be identified through the use of a unique MTC, which can be easily identified in our systems.</p>	Noted.
Peel Ports	<p>Appears to be a low cost solution and will work if used consistently but there is always the issue that the Users of this information will not appreciate the importance of an address field.</p> <p>One would imagine a coded field would provide more security of capturing important information such as the MTC but if used in combination with an MTC there should be higher opportunity for successful application of this rule.</p>	Noted.
Southern	No. This would assist in identification of a difference metered boundary point.	Noted.

Electric Power Distribution & Scottish Hydro Electric Power Distribution		
SP Distribution & SP Manweb	No - but care must be taken to ensure that all MPANS are properly identified in this manner	Noted.
SSE Energy Supply Ltd	No	Noted.
UK Power Networks	Yes in the sense that the address line 1 can be modified and may diverge. However controls on changes of line 1 details are possible.	Noted.
Western Power Distribution	This would be a problem if used for automated processes but ok if used as an identifier.	Noted.
Question 13	Do you believe there will be consequential changes to other industry codes⁴ as a result of each option or solution?	Working Group Comments
British Gas	Yes, as captured in section 9 of the consultation.	Noted.

⁴ Please refer to section 9

Electricity North West	Both solutions MAP09 Solution 1 and 2 Option 1 No but bi-laterals between supplier and HHDC Option 2 No but bi-laterals between supplier and HHDC Option 3 HHDC BSCP MRA (DTC) Option 4 HHDC BSCP or trilateral between supplier, HHDC and distributor	Noted.
Elexon	In Option 3 where new data flows are introduced, there are potential impact on relevant BSCPs (particularly for Half Hourly Data Collectors in BSCP 502)	Noted. New data flows have an MRA impact.
Forth Ports	N/A	
GDF Suez	Yes, Option 3 will require changes to the MRA and the DTC.	Noted.
Northern Powergrid	We believe there will be no consequential changes to other industry codes other than to the Market Domain Data (MDD), Master Registration Agreement (MRA) and the Balancing & Settlement Code (BSC) already identified within the consultation.	Noted.

NPower	<p>Yes.</p> <p>We believe these have largely been identified in the consultation document.</p> <p>There is currently no requirement on the HHDC to send the gross energy data to the LDNO or Boundary Point Supplier. Some of the options may require an obligation being placed on the HHDC (via the Boundary Point Supplier) to send the gross energy data.</p> <p>The allocation of the unique MTC of 996 to the Boundary Point MPAN where Difference Metering is being applied would need to be included as part of the Metering Dispensation process.</p>	Noted.
Peel Ports	Don't know	
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	If additional data flows are required, there will be a need for changes to the MRA and any relevant BSCPs.	Noted.
SP Distribution & SP Manweb	Yes – as stated in consultation MRA & BSC will be impacted	Noted.
SSE Energy	Yes	Noted.

Supply Ltd		
UK Power Networks	Yes if new flows are required.	Noted.
Western Power Distribution	BSC/MOCOPA	Noted. The Working Group do not believe that MOCOP will be directly impacted and confirmed with WPD.
Question 14	The Working Group draws your attention to DCP 142⁵ and asks if the change due to be implemented on the 01 October 2013 in to DCUSA will produce a problem for any of the options e.g. electronic v manual billing?	Working Group Comments
British Gas	<p>This is likely to cause a problem for any proposed annual reconciliation for capacity and reactive power. However, we do not agree that there should be an annual reconciliation for capacity and reactive power. We favour an approach which simply charges for capacity and reactive power based on the net settlement data received.</p> <p>The issue of managing the boundary capacity is a contractual issue between the private network and the DNO. For the small number of private networks, boundary capacity can be agreed and enforced through the connection agreement rather than through highly complex DUoS charging arrangements. We note that boundary capacity for IDNO sites is not managed through DUoS and a similar approach should be adopted for private networks.</p>	The Working Group noted that the annual reconciliation under solution 2 could prove difficult with e-billing. While the Working Group agrees that capacity is a matter between the parties, the Working Group feel that continued charges in respect of the boundary is the best solution. The Working Group's response to the British Gas' proposal is given at Q22.

⁵ Using D2021 for all invoices/credit notes if it is used at all

Electricity North West	<p>Yes, we would have to send an electronic invoice in all instances. DCP142's intent was for electronic invoice amendments where the initial invoice was sent by an electronic invoice however the legal text covers any invoice.</p> <p>In our opinion we may need to consider a change in this area to limit it to initial invoices to allow for paper/pdf bills to be produced for instances where parties may not be able to amend their systems or do not wish to do so for the small volumes currently being processed at present.</p>	Noted.
Exelon	N/A	Noted.
Forth Ports	Not cited to this	Noted.
GDF Suez	None foreseen.	Noted.
Northern Powergrid	We do not believe that the implementation of DCUSA change proposal DCP 142 - 'Using D2021 for all invoices/credit notes if it is used at all', due to be implemented in October 2013, will cause Northern Powergrid any problems with any of the options outlined.	Noted.
NPower	As a Supplier we do not see a problem for any of the options. We would also add that we do not understand why any of the options would require manual billing. Providing the data is made available, it should be possible to manually load the data into the existing DUoS billing system in order to produce an electronic bill.	Noted that it is dependent on the current flexibility of the DNOs billing system.
Peel Ports	Should have no effect unless the PNO are also expected to follow the DNO in electronic billing and a PNO may not have the facilities or capabilities to produce electronic bills for what is a none core activity of the Network Operator.	Noted.
Southern Electric Power	As processes are currently being revised for DCP 142 we see no issue with incorporating this change should it be approved.	Noted.

Distribution & Scottish Hydro Electric Power Distribution		
SP Distribution & SP Manweb	<p>Solution 1 Option 2 or 3 will not impact DCP 142 as all invoices will be issued electronically.</p> <p>Solution 1 Option 1 or 4 will impact DCP142 as these options require a manual invoice and therefore will not comply if the user normally receives electronic invoices.</p> <p>Solution 2 will not comply with DCP142 as invoices will be issued electronically each month to all parties but the reconciliation of kVAh and exceeded capacity will require a manual invoice to be issued.</p>	<p>Noted.</p> <p>It may be an issue for some DNOs billing systems but not all.</p>
SSE Energy Supply Ltd	As Supplier, unsure of the billing implications for DNO's	Noted.
UK Power Networks	<p>DCP142 states (in respect of HH settled sites)</p> <p>Where the Company submits, and the User agrees to receive, accounts by sending an electronic invoice it shall use an electronic invoice for all of that User's accounts</p> <p>Therefore, if the boundary supplier receives electronic invoices we believe the invoice in respect of the boundary must be electronic.</p> <p>This may impact option 4 of solution 1, as the invoice calculation is done outside of normal billing systems, depending on how the distributor raises electronic invoices.</p>	Noted.
Western	We don't believe so.	Noted.

Power Distribution		
Question 15	For the gross boundary Solution 1 which option (1-4) do you prefer? Rank your preferred options in order of preference with 1 being your most preferred option and 4 being your least preferred option.	Working Group Comments
British Gas	We do not support any of the options.	Noted.
Electricity North West	Small take up	
	Option	Ranking (1 best)
	Option 1 – LDNO sums the data	2
	Option 2 - Pseudo MPAN	4
	Option 3 – new data flows	3
	Option 4 – HHDC spreadsheet	1
	Large take up	
	Option	Ranking (1 best)
	Option 1 – LDNO sums the data	3
	Option 2 - Pseudo MPAN	4
Option 3 – new data flows	1	

	Option 4 – HHDC spreadsheet	2		
Elxon	As the BSCCo, we do not have a clear preference however the cost of implementing option chosen will have to be proportionate with the low volume whilst remaining robust should the volume ramp up.		Noted.	
Forth Ports	Option 3 is the preference – but not likely to be practical today unless the industry believes that third party access with difference metering solutions is to be widely taken up. At this state we are not seeing any customers seriously exploring this option beyond those that took up third party before all of the complications were fully documented and understood.		Noted.	
GDF Suez	In order of preference, most preferred first: 1 or 3 (depending on volumes) 2 4		Noted.	
Northern Powergrid	With respect to the gross boundary Solution 1, and taking into account the answers given to questions 8A & 8B, Northern Powergrid’s preference from the options outlined is as follows:-		Noted.	
	Ranking	Solution 1 options		Comments
	1	Option 2		Low cost for low volumes. Implementation costs low but resource costs high
	2	Option 3		Higher cost but necessary for high volumes. Implementation costs high but resource costs low.
	3	Option 4		Low cost but expensive to run. High resource costs

	4	Option 1	Low cost but expensive to run. High resource costs	
NPower	We believe we have already covered this in our response to question 8, and that our preference is dependent on the level of take up below: <ul style="list-style-type: none"> • Low take up - Option 4 of Solution 1 • High take up - Option 3 of Solution 1 			Noted.
Peel Ports	<ol style="list-style-type: none"> 1 Option 2 – for practical purposes 2 Option 4 – 3 Option 1 – no transparency or validation 4 Option 3 – would be the preferred if commercially viable (not anticipated to be viable without mass take up) 			Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	<ol style="list-style-type: none"> 1st – option 4 2nd – option 1 3rd – option 3 4th – option 2 			Noted.
SP Distribution & SP Manweb	<ol style="list-style-type: none"> Option 2 1 Option 4 2 Option 3 3 Option 1 4 			Noted.
SSE Energy Supply Ltd	Options 2, 3, 1, 4			Noted.
UK Power	Option 3			Noted.

Networks	Option 2 Option 4 Option 1	
Western Power Distribution	2	Noted.
Question 16	Do you believe that under Solution 2 that a reconciliation of reactive and capacity charges should be performed? If so should it be monthly, annually or another frequency?	Working Group Comments
British Gas	There should be no reconciliation performed, and to do so seems like an unnecessary administrative burden. As we have said in response to Q.14, the issue of managing the boundary capacity is a contractual issue between the private network and the DNO. For the small number of private networks, boundary capacity can be agreed and enforced through the connection agreement rather than through highly complex DUoS charging arrangements. We note that boundary capacity for IDNO sites is not managed through DUoS and a similar approach should be adopted for private networks.	Noted.
Electricity North West	Yes, but not for insignificant volumes. The costs may well outweigh the income. When volumes are significant it is anticipated that this may need to be monthly.	Noted.
Elexon	N/A	
Forth Ports	The reconciliation is a clumsy approach, it creates billing complexity and uncertainty and increases cost to the private network and the suppliers through additional corrections having to be made. There are issues with the customers and/or suppliers changing or leaving the network. Remember also that where there is difference metering the private network is liable to have a large number	Noted.

	of its own (non-third party) customers, such reconciliations would need passed onto them as well as the third party customers. This element alone is enough to suggest that Solution 2 is not practical.	
GDF Suez	Yes, annual.	Noted.
Northern Powergrid	<p>Whilst solution 2 is not our preferred option, if this solution is taken forward, there will have to be consideration of some form of reconciliation.</p> <p>There are however high risks in carrying this out, which would need to be considered, and a view taken of how useful the results would be as the boundary values could be very different to sum of the parts.</p>	Noted.
NPower	We do not believe Solution 2 to be viable. This question should be explored further dependent on the outcome of the consultation.	Noted.
Peel Ports	<p>Yes as we have current evidence of significant impact on our network capacity due to a very small number of large users with power factor issues affecting the overall capacity / exceeded capacity in area's.</p> <p>Without this Ofgem could argue that our apportionment of the overall capacity charges for the none third party users was not 'fair' and 'proportionate' where we cannot demonstrate that large individual users who may opt for third party supply could be significant contributors of the issue but not contributing to the liability/ cost.</p> <p>The reconciliation method is far from ideal as this is retrospective, difficult to validate particularly when the problem may have been rectified. Difficult to charge and apportion if the supplier or tenant has changed. The later the period of reconciliation the more difficult it will be to correctly allocate/ apportion and the more frequently it is undertaken the more cost and administration needs to be built into the process.</p>	Noted.

	Do not believe Solution 2 offers any benefit only further risk, cost and complications.	
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	SSEPD does not support solution 2, however should this solution be adopted by Industry a reconciliation of reactive and capacity charges should be carried out monthly.	Noted.
SP Distribution & SP Manweb	A reconciliation of reactive and capacity charges should be performed to enable billing to comply with the charging statement and these charges could potentially be substantial. This reconciliation should be performed monthly to accommodate change of agent and especially to bill the kVArh.	Noted.
SSE Energy Supply Ltd	Yes, Monthly	Noted.
UK Power Networks	We don't believe solution 2 is appropriate at all as noted in our comments above.	Noted.
Western Power Distribution	Yes – monthly.	Noted.
Question 17	Which outcome do you prefer i.e. Solution 1 (stating which of option 1-4) or Solution 2?	Working Group Comments

British Gas	Neither.	Noted.
Electricity North West	Solution 2	Noted.
Elexon	N/A	Noted.
Forth Ports	Solution 1, option 3 (with either option 2 or 4 in the interim)	Noted.
GDF Suez	Solution 1 Option 1 or 3 (depending on volumes). We support Solution 1 as the most immediately practical option with the lowest cost, but see comments in 22 below.	Noted.
Northern Powergrid	As previously stated in questions 8A & 8B and 15, we prefer Solution 1 option 2 for a lower take up and solution 1 option 3 as a more enduring solution if/when the take up increases.	Noted.
NPower	We believe we have already covered this in our response to question 8, and that our preference is dependent on the level of take up below: <ul style="list-style-type: none"> • Low take up - Option 4 of Solution 1 • High take up - Option 3 of Solution 1 	Noted.
Peel Ports	Solution 1 – option 2 / then option 4 for small volume uptake and option 3 if the number of TPA's increase.	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power	Solution 1 – option 4	Noted.

Distribution		
SP Distribution & SP Manweb	Solution 1 option 2	Noted.
SSE Energy Supply Ltd	Solution 1, Option 2	Noted.
UK Power Networks	Solution 1 option 3	Noted.
Western Power Distribution	Solution 1 – Option 2	Noted.
Question 18	Under the alternative solution in order to achieve reconciliation how should the DNO receive the gross data?	Working Group Comments
British Gas	We do not agree that there should be any reconciliation. It would appear to us to introduce an undesirable amount of complexity to a small and contained issue. Boundary capacity usage can be managed by the DNO on a contractual basis without the need for unnecessarily complex DUoS charging arrangements or industry changes (as is done so currently for the boundary capacities of IDNO connections).	Noted.
Electricity North West	We believe that the options available to solution 1 equally apply here so we have copied down the tables. Small take up	Noted.

	Option	Ranking (1 best)	
	Option 1 – LDNO sums the data	2	
	Option 2 - Pseudo MPAN	4	
	Option 3 – new data flows	3	
	Option 4 – HHDC spreadsheet	1	
	Large take up		
	Option	Ranking (1 best)	
	Option 1 – LDNO sums the data	3	
	Option 2 - Pseudo MPAN	4	
	Option 3 – new data flows	1	
	Option 4 – HHDC spreadsheet	2	
	The receipt of the data from the HHDC would be used to determine when to start undertaking reconciliation, when to determine the frequency of reconciliation and when there is a need to introduce new data flows in preference to the spreadsheet.		
Elexon	N/A		Noted.
Forth Ports	Do not see the logic of the alternative solution.		Noted.

GDF Suez	1 or 3, depending on volumes.	Noted.
Northern Powergrid	If the alternate Solution 2 was adopted, we believe that the LDNO should receive the gross data via proposed new industry flows as outlined in Solution 1 – Option 3.	Noted.
NPower	We do not believe Solution 2 to be viable. This question should be explored further dependent on the outcome of the consultation.	Noted.
Peel Ports	<p>No logic in this approach and the fact that it still requires the data required by Solution 1 but just serves to add further handling and administration simply results in further cost.</p> <p>The fact the alternative option doesn't add anything other than further processes, complexity and confusion and still requires Gross data surely means this is not a viable option. No benefit other than transparency and there are alternative means to offer transparency.</p> <p>Means of providing Gross data are already covered in Solution 1.</p>	Noted.
Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	If the alternative solution is adopted the DNO should receive the nett data from the boundary supplier's DC and the gross data from the embedded suppliers' DCs on existing industry flows. Billing would then process using existing billing systems.	Noted.
SP Distribution & SP	The gross data would require to be received via a spreadsheet.	Noted.

Manweb		
SSE Energy Supply Ltd	By totalising the Settlement data received from existing DTC flows	Noted.
UK Power Networks	We don't believe solution 2 is appropriate at all as noted in our comments above.	Noted.
Western Power Distribution	Pseudo D0036.	Noted.
Question 19	DCP 158 is due to be implemented in the next DCUSA release following authority consent. Do you have a preference on the date that DCP 158 is implemented in to the DCUSA?	Working Group Comments
British Gas	Given that a number of the proposed solutions require industry changes, which will take time to progress, and billing/validation system changes, the 'next DCUSA release' may not be achievable without DNOs instantly needing to seek derogations.	Noted. It is possible that other industry parties may require derogations.
Electricity North West	<p>This is optimistic. It may well be acceptable to those (Suppliers/HHDCs/Distributors) who already have some sites operating in the market place but if system changes are required and/or the introduction of new data flows needed this is very unlikely.</p> <p>If changes to the methodology and changes to charging statements are required, notice is needed and limited to twice per year.</p> <p>We believe the earliest opportunity is April 2014 but even this is optimistic and only deliverable for the basic simple changes.</p>	Noted.

Elxon	N/A	Noted.																
Forth Ports	No, we are not a DCUSA party.	Noted.																
GDF Suez	No	Noted.																
Northern Powergrid	This would depend on what solution and option was to be agreed.		Noted.															
	<table border="1"> <thead> <tr> <th colspan="2">Proposal</th> <th>Proposed implementation date</th> </tr> </thead> <tbody> <tr> <td rowspan="4">Solution 1</td> <td>Option 1</td> <td>April 2014</td> </tr> <tr> <td>Option 2</td> <td>April 2014</td> </tr> <tr> <td>Option 3</td> <td>Dec 2014 (in line with current derogation for a new billing system)</td> </tr> <tr> <td>Option 4</td> <td>April 2014</td> </tr> <tr> <td colspan="2">Solution 2</td> <td>Dec 2014 (in line with current derogation for a new billing system)</td> </tr> </tbody> </table>			Proposal		Proposed implementation date	Solution 1	Option 1	April 2014	Option 2	April 2014	Option 3	Dec 2014 (in line with current derogation for a new billing system)	Option 4	April 2014	Solution 2		Dec 2014 (in line with current derogation for a new billing system)
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NPower	This would appear an appropriate implementation approach for options that require no system changes. For those options that require system changes we would require 3 months lead time following a decision.	Noted.																
Peel Ports	No	Noted.																
Southern Electric Power Distribution & Scottish Hydro Electric	April 2014 for a small volume situation with manual billing. April 2015 or later for a permanent solution which may be requiring system updates?	Noted.																

Power Distribution		
SP Distribution & SP Manweb	<p>Dependent upon the solution and option adopted.</p> <p>Solution 1 Option 4. No lead time for DNO</p> <p>Solution 1 Option 2. No lead time for DNO</p> <p>Solution 1 Option 1. 3 to 6 months to implement changes to the billing application.</p> <p>Solution 1 Option 3. 6 months to implement changes to billing application</p> <p>Solution 2. 6 months to implement changes to billing application.</p>	Noted.
SSE Energy Supply Ltd	No	Noted.
UK Power Networks	There are EDNO sites in existence now so this is not a matter than can wait a long time.	Noted.
Western Power Distribution	No	Noted.
Question 20	<p>Which DCUSA General Objectives does the CP better facilitate? Please provide supporting comments.</p> <ol style="list-style-type: none"> 1. The development, maintenance and operation by each of the DNO Parties and IDNO Parties of an efficient, co-ordinated, and economical Distribution System. 2. The facilitation of effective competition in the generation and supply of electricity and (so far as is consistent with that) the promotion of such competition in the sale, distribution and purchase of electricity. 	Working Group Comments

	<p>3. The efficient discharge by each of the DNO Parties and IDNO Parties of the obligations imposed upon them by their Distribution Licences.</p> <p>4. The promotion of efficiency in the implementation and administration of this Agreement and the arrangements under it.</p> <p>5. compliance with the Regulation on Cross-Border Exchange in Electricity and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.</p>	
British Gas	We do not agree that general objective two is better facilitated. Whilst the aim of the change is to put in place a process for more appropriate DUoS charging arrangements for customers embedded within a private network, we believe that the cost and administrative burden of the proposed solutions are unlikely to facilitate the engagement of all suppliers.	Noted.
Electricity North West	We believe that general objective two is better facilitated by ensuring that a transparent common process is developed and implemented in dealing with embedded customers within private networks.	Noted.
Elexon	N/A	
Forth Ports	Solution 1 best fits the objectives, particularly objective 4 – Solution 2 clearly does not fit well with objective 4.	Noted. The Working Group considers that objective 4 is neutral in this instance because it relates to the governance of the agreement itself.
GDF Suez	Agree with working group assessment.	Noted.
Northern	We believe that objective 2 is better facilitated by DCP 158 and in particular Solution 1 as it should provide clarity in the arrangements for charging DUoS in	Agree.

Powergrid	<p>relation to PNO sites where end users seek to utilise the competitive supply market, thereby assisting competition in the supply of electricity to such sites.</p> <p>We believe that objective 3 is better facilitated as DCP 158 Solution 1 is an efficient means of charging DUoS in respect of PNO sites where the difference meeting solution applies.</p>	
NPower	<p>We believe that Solution 1 better facilitates the following DCUSA General Objectives:</p> <p>Objective 2 – Competition in supply of energy to sites connected to private networks was introduced on 9th November 2011 through the Electricity and Gas (Internal Markets) Regulations 2011. DCP158 is intrinsically linked to this new market facility by improving the process which allows a site embedded on a private network to choose their Supplier.</p>	Noted.
Peel Ports	<p>Solution 1 best fits the objectives, particularly objective 4; Solution 2 clearly does not meet objective 4 given the added processes, cost and complexity</p>	Noted. The Working Group considers that objective 4 is neutral in this instance because it relates to the governance of the agreement itself.
Southern Electric Power Distribution & Scottish Hydro Electric Power	<p>The CP better facilitates DCUSA General Objective 2 as the change seeks to put arrangements in place to enable customers on private networks to readily access competitive electricity supply, facilitating greater reach of supply competition.</p> <p>The CP also better facilitates DCUSA General Objective 2 as the arrangements will enable an EC decision on access to supply competition to be practically implemented.</p>	Noted.

Distribution		
SP Distribution & SP Manweb	We agree with the working group's view that the change proposal better facilitates objective 2. This CP results in both licence exemption which is a form of competition, and a defined process allowing customers to choose their supplier facilitating competition.	Noted.
SSE Energy Supply Ltd	1, 3, 4	Noted. The Working Group considers that objective 4 is neutral in this instance because it relates to the governance of the agreement itself.
UK Power Networks	General Objectives: 2. Licence exemption is a form of competition 3. the most appropriate, efficient and cost reflective approach to the charging for use of the direct connection to the licenced distributor's system is central to Objective No 3. Charging directly and solely for the usage at the connection to the licence exempt network better meets objective 3.	Noted.
Western Power Distribution	2	Noted.
Question 21	<p>Which DCUSA Charging Objectives does the CP better facilitate? Please provide supporting comments.</p> <p>1. That compliance by each DNO Party with the Charging Methodologies facilitates the discharge by the DNO Party of the obligations imposed on it under the Act and by its Distribution Licence</p>	Working Group Comments

	<p>2. That compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)</p> <p>3. That compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business</p> <p>4. That, so far as is consistent with Clauses 3.2.1 to 3.2.3, the Charging Methodologies, so far as is reasonably practicable, properly take account of developments in each DNO Party's Distribution Business</p> <p>5. That compliance by each DNO Party with the Charging Methodologies facilitates compliance with the Regulation on Cross-Border Exchange in Electricity and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.</p>	
British Gas	<p>We agree with the working groups view that Charging Objective 1 is likely to be better facilitated by this change.</p> <p>We do not agree that charging objective two is better facilitated. Whilst the aim of the change is to put in place a process for more appropriate DUoS charging arrangements for customers embedded within a private network, we believe that the cost and administrative burden of the proposed solutions are unlikely to facilitate the engagement of all suppliers.</p>	Noted.
Electricity North West	We believe there is no methodology change required but more a tariff understanding for billing purposes so that it better facilitates the charging	Noted.

	objective associated with the facilitation of competition in the generation and supply of electricity and not restrict, distort, or prevent competition in distribution.	
Elxon	N/A	Noted.
Forth Ports	N/A	Noted.
GDF Suez	Agree with working group assessment.	Noted.
Northern Powergrid	We believe that objective 2 is better facilitated by DCP 158 and in particular Solution 1 as it should provide clarity in the arrangements for charging DUOS in relation to PNO sites where end users seek to utilise the competitive supply market, thereby assisting competition in the supply of electricity to such sites.	Noted.
NPower	<p>We believe that Solution 1 better facilitates the following DCUSA Charging Objectives:</p> <ul style="list-style-type: none"> • Objective 1 – The new market facility introduced uncertainty as to how DUoS charging should be applied on private networks where a Difference Metering arrangement is in place. DCP158 will introduce a common methodology for charging at such sites and put in place formal data provision arrangements in order to facilitate the methodology. • Objective 2 – DCP158 will provide Licence Exempt Distribution Network operators with certainty as to how DUoS charging will be applied on their private networks where Difference Metering is being applied. This will allow them to manage the energy flows on those networks and any connections to it in the most efficient manner. Licence exemption can be viewed as a type of competition. 	Noted.
Peel Ports	Either option comply with these requirements.	Noted.

Southern Electric Power Distribution & Scottish Hydro Electric Power Distribution	We believe this CP better facilitates DCUSA charging objectives 1 and 2. For reasons assessed by the working group.	Noted.
SP Distribution & SP Manweb	We agree with the working group's view that the change proposal better facilitates objective 1 & 2. Objective 1 is better facilitated by this CP as it ensures that sufficient DUoS billing and formal data provision arrangements are in place for Difference Metered private networks, hence facilitating private networks within industry arrangements. Objective two is better facilitated by this is CP as licence exemption is a form of competition.	Noted.
SSE Energy Supply Ltd	1, 3, 5	Noted. The Working Group considers that objective 5 is neutral in this instance.
UK Power Networks	Charging Objectives: 1. The Act provides for Licence exempt networks. 2. Licence exemption is a form of competition 3. Charging fully in respect of the directly connected boundary to the licence exempt distribution system is most likely to charging fully in accordance with the approved EDCM and CDCM methodologies.	Noted.
Western	1 and 2	Noted.

Power Distribution		
Question 22	Are there any alternative solutions or matters that should be considered by the Working Group?	Working Group Comments
British Gas	<p><u>The net metering standard DUoS tariff approach:</u></p> <p>A simpler solution with minimal impact on industry systems and processes would be for the licensed network operator to charge their standard DUoS rates to both the supplier of the boundary mpan and the supplier(s) of any embedded mpan(s) based on the normal (net metering) settlement data for both (noting that the applicable DUoS tariff may be different for the two depending on the final voltage of connection). In this way the embedded customer will be charged the same rate, using the same processes and systems as any equivalent customer connected to the licensed DNO. This is likely to facilitate maximum engagement by Suppliers to the benefit of the end customer.</p> <p>We recognise that the private network operator will need to recover its Embedded Use of System costs for relevant embedded mpans. The simplest way to do this is for the Private Network Operator to charge the licensed DNO in accordance with the private networks' approved UoS methodology for relevant embedded mpans. This is likely to facilitate maximum engagement by the Private Network Operators since their costs will be recovered from a single party with no need to implement or maintain a change of supplier process.</p> <p>We also recognise that licensed DNOs who have received DUoS income in relation to embedded customers, will be 'out of pocket' if this revenue is to be counted against their overall revenue allowances and they then need to pay the charges</p>	<p>This proposed solution will be in breach of the internal markets regulations. The Electricity Act 1989 states that the definition of the UoS charge "means charges made or levied, or to be made or levied by, the licensee for provision of UoS and certain other services as part of its distribution business</p>

	<p>levied by the Private Network Operator for Embedded Use of System. This can be rectified by classifying such costs as a pass-through item in the DNO licence – the necessary licence changes could be captured as part of the RIIO ED1 process. We believe that this approach will be most beneficial for DNOs as well since there will be no need for complex billing system changes.</p> <p>Naturally, as this solution would introduce a new pass-through cost to be recovered from the wider DNO customer base, we would be reliant on Ofgem to ensure that the private networks UoS methodologies were appropriate and did not place excessive costs on the wider customer base.</p> <p>Our suggested approach requires no changes to industry data flows and is likely to require minimal, if any, changes to billing or validation systems. We believe it is the least industry cost solution whilst also better facilitating competition in the supply to customers embedded within private networks.</p> <p>This proposed solution will require some licence changes, but as mentioned, these can be captured as part of the RIIO ED1 process and be implemented by April 2015. This proposed solution may also require some minimal changes to the charging methodologies of both licensed and private networks but these changes will be administrative in nature rather than fundamental changes to the basis or structure of charges.</p>	<p>to any person, but does not include connection charges. Therefore this solution would provide for a levy on a third party Supplier and on a Supplier resulting in a cross subsidy between the DNOs customers and the PNOs customers.</p>
Electricity North West	<p>Alternative solution</p> <p>None</p> <p>Other matters</p> <p>We need to consider whether there needs to be a bi-lateral between supplier and supplier to allow the supplier at the boundary to receive and process gross data</p>	<p>Noted, it will be picked up as part of our legal review. The boundary Supplier is responsible for the accuracy of the data at the boundary points including the gross data and can</p>

	<p>(since some of this data is not theirs where the embedded customer has chosen a different supplier).</p> <p>There needs to be an understanding that embedded customers (with registered MPANs) within a private network are not being billed to the Supplier by the Licensed Distributor, and that all embedded customers (with registered MPANs) will be billed to the supplier of the boundary MPAN. Where this sits within DCUSA needs further discussion.</p> <p>Both of these could be added to the supplier to supplier section of DCUSA.</p>	therefore facilitate the exchange of information. The Working Group noted that the Change Proposal covered off these issues.
Elxon	N/A	Noted.
Forth Ports	Private networks are not DCUSA parties (neither should they be), however, there does appear to be a need for a mechanism to ensure that private networks (especially those with (or in the process of obtaining) Ofgem approval for the methodology) are cited to change processes that have an impact on them.	Noted.
GDF Suez	<p>Yes.</p> <p>While Option 1 may be the most practical immediate solution from a Supplier/DNO/Agent perspective, from a customer perspective it has significant limitations.</p> <p>For an embedded customer, the Boundary solution does not offer transparency on DUoS charges as they cannot tell from the invoice values how the DUoS charge applied at the private network boundary has been apportioned to their connection.</p> <p>This may have added consequences for network and capacity management incentives as the embedded customer may find it difficult to relate their consumption to charging band signals.</p> <p>Wider industry consideration needs to be given to measures which could increase the transparency of DUoS charges for embedded customers.</p>	Noted. It is dependent on the PNO's charging methodologies.

Northern Powergrid	No, we do not believe that there are any alternative solutions that should be considered as we feel that the matter has already been discussed at length in the working group.	Noted.
NPower	At this stage we do not have any alternative solutions or matters to be considered by the Working Group.	Noted.
Peel Ports	<p>These changes are governed by licensed parties to be applied to unlicensed parties via a complex and regulated closed industry structure DCUSA.</p> <p>Consideration needs to be given by DCUSA for the specific changes that impact the wider unlicensed users and private network operators in terms of consultation and engagement in the process (no voting rights, or say unless specifically notified and invited to participate).</p> <p>The private network operator will be a primary and fundamental party to enable any such regulatory processes or procedures required to successfully implement and manage the on going connections of the customers on the private network.</p> <p>DCUSA /Ofgem should consider a process of notification to PNO's to ensure inclusion to the relevant changes in data streams and process to ensure the effective management of the complex site mapping and avoid duplication of charges.</p>	Noted. It will be recommended to the DCUSA Panel that PNOs with embedded MPANs identified via the MTC with assistance of the relevant DNO will be notified of future Working Groups and consultations that may impact them.
Southern Electric Power Distribution & Scottish Hydro	Not at this time	Noted.

Electric Power Distribution		
SP Distribution & SP Manweb	No	Noted.
SSE Energy Supply Ltd	No	Noted.
UK Power Networks	No	Noted.
Western Power Distribution	Not that we're aware of.	Noted.