DCUSA DCP 137 Consultation Responses – Collated Comments

Company	Question One - *Do you understand the intent of the CP?*	Working Group Comments
CLP Envirogas	Yes	Noted
ENWL	Yes	Noted
SSE Power Distribution	Yes	Noted
NPG	Yes, we understand that it is not prudent to pay a credit to HV generators connected at a specific primary (which is generation dominated) where the increase in generation will actually incur a cost to the DNO – the reinforcement of the primary.	Noted
UKPN	Yes	Noted
Good Energy	Yes	Noted
RWE	Yes, the intent of the CP is clear.	Noted
SP Distribution & SP Manweb	Yes we understand the intent of the CP.	Noted
WPD	Yes	Noted
GTC	We understand the intent of the proposal at the high level context. However it is unclear as to what should apply where a DNO network is generation dominant, but the IDNO network is not (and vice versa). Who determines what charge should apply IDNO or DNO?	The Working Group noted that the concept under DCP 137 is that the DNO is applying charges for the use of their network. Information on the generation dominated areas will be included within the LC14 charging statement. The information will list the primary substation along with HV generation connections and IDNO connections. It will be for the IDNO to reflect the appropriate charge in their network area for any HV generation that they may have connected. If a network is not identified as generation dominated then normal HV generation charges will apply.

		The Working Group noted all respondents understood the intent of the CP.
Company	**Question Two - *Are you supportive of the principles established by this proposal?***	**Working Group Comments**
CLP Envirogas	No. The justification for GDUoS credits is that generation capacity allows demand reinforcement to be deferred; specifically its presence allows more demand to be connected to the primary substation without additional reinforcement expenditure. If incremental high voltage connected generation causes the primary substation to require reinforcement, in our opinion it is the incremental generation that should be discouraged. This is already affected via the significant upfront capital connection charge to be paid by the new generator to the DNO. Accordingly, there is already a significant and direct charging signal in place to discourage high voltage generation from connecting or increasing capacity where doing so requires reinforcement of the primary substation and associated expenditure. We would also point out, having requested new generation connection offers, that the only cost signal received is that of the upfront capital connection cost. The ongoing GDUoS credit or charge is not included, so in this regard it does not operate as a signal to those generators that will disturb the equilibrium. The proposal not only ignores this predominant signal of upfront charging, it takes a currently balanced demand generation position (for a primary substation forecast to swing to a generator dominated position within 2 ½ years) and encourages additional demand and less generation through a notional cost signal. In this proposal, any existing generator who is forecast within say 2 ½ years to be connected to a generator dominated primary substation is by definition contributing significantly to distribution network efficiency. However, the proposal is to discourage and penalise such a generator by removing or reducing its GDUoS credits, based upon forecast data and the possible actions of an unidentified notional new generator. We believe that the existing generator should be rewarded and encouraged up until the point it is no longer benefitting the network. The proposal is therefore perverse in that it would not reward efficiencies, rather it would discourage them. Further, the majority of demand is generally connected at low voltage and sees neither a step change in DUoS charges nor any other change in charges if reinforcement is carried out at the	The Working Group observed that generation growth can also be caused by LV generation growth and by reductions in net demand at both LV and HV, rather than solely by increases in localised HV generation caused by new HV generation connections. The Working Group believe that the issue highlighted, while it is an issue in its own right, is not the problem that the Generation Dominated Areas proposal is trying to solve.

	primary substation. Once connected, a generator cannot simply relocate to another primary substation. In this context, any locational signal needs to be aimed at potential new generation rather than established generators. Accordingly, potential generation should be provided with upfront capital connection cost and GDUoS pricing signals which encourage appropriate locational decisions in support of efficient and effective network management. Further, basing any change in current GDUoS credits on forecast data is not cost reflective as it reduces credits in a period where existing generators provide actual network support. Such signals must be aimed at planned new generation in line with and reflective of the cost implications associated with the locational decision of those whose contemplated actions are forecast to change the current efficiency and balance of the distribution system. We believe that GDUoS credits should be maintained for existing generators, up to the point where generation does in fact dominate, based upon actual data. Given that DNOs will check primary substation data on an annual basis (per paragraph 7.16), the decision on whether a primary substation is demand or generator dominated can be made annually using actual data. There is no need to use inaccurate forecasts. What would also be a useful locational signal for existing and potential generators would be information on the current balance between demand and generation at a primary substation, the likely future change in that balance and speed of such change . In summary, we do not support the proposal which reduces GDUoS credits for existing generators in periods when they are supporting the networks and thereby reducing costs, when such a reduction is based on something which may or may not happen in the future, using long range forecasts which are likely to be inaccurate, and will certainly be wrong if the GDUoS charging signals work for incremental generation.	
ENWL	Yes	Noted
SSE Power Distribution	Yes	Noted
NPG	Yes, we are supportive of the principle that generators should not be incentivised to connect at a primary where that primary is close to becoming generation dominated and in need of reinforcement. However, we do not think the penetration of Generation Dominated Areas currently (or forecast) is sufficient to warrant this change to be progressed at this time and feel that it	The Working Group are progressing the proposal on whether it better meets the DCUSA Objectives. The Working Group noted that at this stage there is predicted to be little generation

	would be more prudent to monitor the situation over the next few years.	domination across the DNO areas, however, it is not in the remit of the Working Group to quantify by how much the DCUSA Objectives are better facilitated but rather to determine solely whether or not they are better facilitated. The Working Group assess that the implementation costs are smaller than the benefits that will be derived.
UKPN	Yes, we are supportive of improving the cost reflectivity of the methodology where it is cost efficient to do so.	Noted
Good Energy	No, it discriminates unfairly against generators by proposing locational DUoS tariffs for generators and not for demand. This does not seem to recognise that the future progression of networks needs to manage demand and generation as equal customers.	The Working Group noted that this Change Proposal is about the implementation of locational credits and not about applying locational charges. The group does not believe that the CP is discrimatory as it is seeking to remove credits where use is seen to increase the need to potentially reinforce the network. Demand users are currently seen as potentially needing to increase network investment.
RWE	Generators on the HV and LV network reduce the need for network reinforcement by offsetting local demand and the current methodology of awarding them credits is cost reflective and should prevail. The DCP137 proposal to remove credits from HV generators connected to primary substations that are generator dominated is also fair given the rationale that such generators do not reduce network reinforcement need. The assessment methodology for determining whether a primary substation is currently generation dominated makes sense. Reviewing the status of primary substations on an annual basis is also supported. Basing the level of entitlement on forecasts is more contentious. The proposed approach to setting credits depends heavily on speculation by DNOs about future levels of demand and generation over the next 10 years. While giving new connection applicants an indication of	The Working Group noted that the respondent's first paragraph is supportive. With regards to the second and third paragraphs the Working Group noted that DNO forecasts are not speculative but rather are based on documented assumptions using the best available published data at that time. Credits are paid based on forecasts that generators will offset the need for demand reinforcement. If DNOs did not use forecasts

	future network cost changes is useful and can act as the desired price signal in itself; actually charging based on forecasts does not appear strictly cost reflective. One issue to be addressed if forecasts are used is that some form of incentive/penalty measure needs to be in place for the DNO's to make accurate forecasts. The working group have concluded that no refunds of credits should be made if forecast state of generator dominance does not materialise. In our view without an appropriate measure in place there is a driver for the DNO to forecast higher levels of generator dominance.	then these credits could not be paid. It was noted that the respondent assumes that DNOs can benefit from the reduction in credits paid. This is not the case as DNOs are neutral to the benefit/credit that is paid. The credits/benefits are paid by demand users in return for the forecasts of the reduction in costs that will be obtained through reducing the need for demand reinforcement.
SP Distribution & SP Manweb	Yes we are supportive of the principle of the CP.	Noted
WPD	Yes	Noted
GTC	In principle. However we have difficulty in understanding how this will work in practice for embedded networks which themselves may or may not be generation dominant; i.e. there is unlikely to be net export from IDNO network to DNO's upstream network.	Please see response to question 1.
Company	**Question Three - *Do you have any comments on the proposed legal text?***	**Working Group Comments**
CLP Envirogas	No comment on the legal text.	Noted
ENWL	We have reviewed the legal text and are happy that it correctly implements the change proposal.	Noted
SSE Power Distribution	No	Noted
NPG	Not at this time.	Noted
UKPN	No	Noted
Good Energy	We have no comments on the proposed legal text other than those made in response to other questions below.	Noted
RWE	No comments	Noted

SP Distribution & SP Manweb	None	Noted
WPD	No	Noted
GTC	We do not think the legal text sets out fully how arrangements apply in respect of downstream embedded networks which may or may not inject energy onto the upstream system. We cannot support the current drafting	The Working Group will detail the application of generation dominated area tariffs in their LC14 statement in line with the detail provided on the other DUoS tariffs. Please see the response to question 1.
Company	**Question Four - *Do you agree with the ten year time horizon and how it has been split? If not, please provide additional details.***	**Working Group Comments**
CLP Envirogas	Firstly we believe that any changes to GDUoS credits should be considered annually and based upon actual data (as set out in the response to question 2) and not forecasts. If a forecast period is to be used we think 10 years is too long for the following reasons: (i) The longer the time frame the more inaccurate it becomes and therefore less cost reflective; (ii) We do not believe that a generator that is forecast to be connected to a generator dominated primary substation in 5 or 7 ½ years should face a reduction in GDUoS credits today; and Given the annual review of charges, there is no reason that an annual forecast should not be used when the assumptions of incremental generation could be validated against live connection offers.	The Working Group observed that the DCUSA Charging Methodologies are currently based on forecasting long run costs and not on actual accounts based costs. The purpose of this is to provide a signal for driving efficient use of the network. The purpose of the 2.5,5, 7.5 and ten year timeframe is to provide a staged signal and avoid a step change in the application of credits.
ENWL	Yes, we agree that a ten year time horizon is a suitable time period to assess the likelihood that a primary substation is likely to become generation dominated. This is also consistent with the approach adopted in the Frontier report.	Noted
SSE Power Distribution	Yes	Noted
NPG	Yes, we agree with the ten year time horizon and that having four time periods seems to be appropriate.	Noted

UKPN	Yes, we agree with the ten year horizon and how it has been split. This provides a pragmatic approach that enables clear pricing steps over a reasonable planning horizon.	Noted
Good Energy	We do not agree with the ten year time horizon and how it has been split because we do not support the introduction of locational DUoS tariffs for generators.	Noted
RWE	A ten year time horizon for forecasts is long - especially when looking a range of technologies with varied deployment lead-times ranging from a few months to a couple of years; and connections that are heavily dependent on changeable Government policy (regarding subsidies). While giving new connection applicants an indication of future network cost changes is useful and should form part of the proposal, actually charging based on forecasts should not occur as it is not cost reflective.	The reason a ten year timeframe was chosen is because it provides a reasonable staged approach rather than a step change. It also gives generators a view of what will happen longer term and thus enables them to prepare.
SP Distribution & SP Manweb	Yes, this time horizon and split seem to be the most appropriate.	Noted
WPD	Yes	Noted
GTC	Judgements based on a 10 year horizon would appear to be open to subjective judgement in many instances. We are therefore not convinced that the legal text sets out the criteria required to ensure such judgement is robust	The values proposed have been set out in the consultation document and DNOs have followed a consistent approach in setting these forecast values. The approach for calculating the forecast will be set out in the CDCM User Manual should this CP be approved. This is consistent with how other forecasts are derived within the methodology. The Working Group do not believe that it is appropriate to "hard code" in DCUSA the method for calculating the forecast due to the fact that the available source data can change. This approach allows DNOs to use the best available data. The Generation Dominated Areas Working Procedure captures the approach for calculating the forecast and will form the

		basis for what is included with the CDCM User Manual. The Working Group notes that the CDCM User Manual is maintained by the DCMF MIG.
	Question Five - ***Do you have any comments on the attached blank CDCM, EDCM and ARP models?***	**Working Group Comments**
CLP Envirogas	No comment.	Noted
ENWL	We have populated the CDCM and EDCM models and are happy they correctly implement the change proposal. We have populated the Annual Review Pack and have the following comments: **<u>Sheet: CDCM Forecast Data</u>** • Cells G24..J29 and G256..J264 should be coloured dark blue representing that 15 months notice is required • Rows 83 and 102 include the HVS tariff which should be removed • Rows 109, 111, 112 & 114 shouldn't be coloured dark blue **<u>Sheet: Table1</u>** • Row 7 – dates should be linked to row 11 in CDCM forecast data tab • Input cells should be coloured light blue **<u>Sheet: Smoothed Input details</u>** • Table 1041 (coincidence factors and load factors) – remove HVS • Formula in B1 returns an error (not sure why) **<u>Volume Forecasts</u>** • Remove HVS to match CDCM input table **<u>Calculation sheets</u>** • Hide calculation sheets or move to one sheet as used in DCP123 **<u>Sheets Y to Y+4</u>** Latest forecast of CDCM revenue (cell F50) should point to row 47 within the "Table1" tab. This will allow Suppliers to paste in the latest DCP66 submission, but still get the actual prices	The Working Group noted the comments and will feed them back to the modelling support consultant.

	where they have already been issued	
SSE Power Distribution	No	Noted
NPG	Not at this time.	Noted
UKPN	No	Noted
Good Energy	No	Noted
RWE	No comments	Noted
SP Distribution & SP Manweb	No	Noted
WPD	No	Noted
GTC	Not reviewed	Noted
Company	**Question Six - *The current methodology uses the latest Long Term Development Statement as the data source used for identifying generation dominated areas. The Working Group still believes that this is the best source of available data; do you agree? If not, what alternative sources do you believe should be used?***	**Working Group Comments**
CLP Envirogas	This is a difficult question to answer without reading each DNO's Long Term Development Statement – these are not all readily available on line. That said we do not believe that the Long Term Development Statement is the best source of information, it does not appear (and does not claim) to be fit for the purpose of determining GDUoS credits. Using WPD's Long Term Development Statement as an illustration: (i) The statement is compiled in accordance with Licence condition 25; and (ii) "..Due to the volume of data and the speed with which it can become outdated, data on the 11kV and LV systems has not been included in the statement." We believe that actual data can and should be used for assessing whether a primary substation is moving towards and is actually generator dominated, supplemented by active connection requests.	The Working Group still believe that the LTDS is the best source of information. Long Term Development Statements are readily available, as required under DNOs' licence conditions. The group believe that the example given is taken out of context about it not being fit for purpose. The illustration provided in the response is more about the volume of data and the change that would need to be provided for the HV and LV systems rather than the data that is provided in the LTDS statement.

		As stated previously, if charges were based on actual data then credits would not be provided in the first place.
ENWL	We agree that the LTDS is the most appropriate source of data and is transparent to customers.	Noted
SSE Power Distribution	Agree that the LTDS is the best source of data currently available and is transparent.	Noted
NPG	We agree that the LTDS is currently the best source of data as it is the most up to date available and DNO specific, however as RIIO-ED1 reporting tools are better understood there may be more appropriate data sources.	Noted. DNOs have an obligation to review the charging methodologies if better data becomes available.
UKPN	Yes we agree that this is the best source of available data. Additionally the LTDS is available in the public domain.	Noted
Good Energy	We are not aware of any alternative sources to use but question the suitability of the Long Term Development Statement as a data source due to its lack of accuracy.	Noted
RWE	No comments	Noted
SP Distribution & SP Manweb	Yes, especially as this provides a consistent approach to the calculation.	Noted
WPD	Yes	Noted
GTC	We need to be convinced that such statements contain meaningful and robust information. Our experience is that this is not always the case.	The Working Group noted the comment. The LTDS is dynamic and will change as the DNO networks are developed. DNOs welcome identification of areas where the respondee believes there are inaccuracies.
Company	**Question Seven** ***- The generation growth was previously based on the DCPR5 Forecast Business Planning Questionnaire assumptions. The Working Group is now proposing to update the generation growth using RIIO-ED1 business plan growth forecasts used to calculate the timescales for generation dominance of each substation. Do you believe that there are any alternative sources for this***	**Working Group Comments**

	information that would be preferable?	
CLP Envirogas	We would prefer the use of actual data, validated on an annual basis. If a forecast must be used, there is no reason that an annual forecast incorporating assumptions of incremental generation validated against accepted and open connection offers could not be used.	See previously comments regarding use of actual data.
ENWL	We believe that the growth rates assumed within the RIIO-ED1 business plans are initially the most appropriate source of this data. However we note that generation growth rates at individual primary substations can vary from the overall average; we therefore welcome the flexibility given by the legal text to amend the growth rate depending on the actual growth seen on the individual primary networks.	Noted
SSE Power Distribution	Not aware of any better alternatives.	Noted
NPG	No we do not believe that there are any alternative sources at this time. The most recently available published data (RIIO – ED1) is appropriate to use and the data sources these are taken from are standard over all DNOs.	Noted
UKPN	We are not aware of an alternative source of forecast that would be preferable.	Noted
Good Energy	We are not aware of any alternative sources to update the forecast generation growth.	Noted
RWE	DNO forecasts of generation growth have proven to be inaccurate in the past, and the methodologies and assumptions used are not clear or readily available for independent scrutiny. An independent growth forecast by Ofgem could be a better approach, providing a consistent and more transparent methodology for across the UK. This would be especially important if actual charges are based on the forecasts, but would be less so if the forecasts are used as an indicative price signal. RIIO-ED1 analysis on the take-up of low carbon technologies appeared to have heavily focused on LV technologies, which seems to be less relevant to the question of whether HV connections should be receiving credits.	The DNO forecasts are based on the best available data at the time, taking into account government forecasts and planned policy. The current source data for the DNO forecasts is reviewed by Ofgem as part of the price control mechanism. As previously stated, LV generation growth and subsequent net demand reduction is likely to be a significant factor in generation dominated areas.
SP Distribution & SP Manweb	No, this seems to be the most appropriate data to use.	Noted
WPD	No	Noted

GTC	We are not aware of any credible sources. Growth in generation will in large part be driven by government policy and incentives.	Noted. The DNO forecasts are based on the best available data at the time, taking into account government forecasts and planned policy.
Company	**Question Eight - *The current methodology uses the size of the installed generation plant. The Working Group has identified that in some circumstances this can trigger a generation dominated area even though there is not HV export capacity at that primary. It is felt that the methodology would be improved by using the observed maximum generation output. Do you agree with the change to the legal text (paragraph 146B of the legal text) to enable this?***	**Working Group Comments**
CLP Envirogas	Agreed, but the difference between the installed and actual should be tracked as part of managing an efficient network.	Noted
ENWL	Yes, we agree with this amendment. The current charging methodology means that HV generators can maintain an export capacity without incurring a material charge and consequently have no incentive to reduce their Maximum Export Capacity even though they may not be using it. Consequently, it would be reasonable to remove any unused generation capacity from the calculation of whether a primary is generation dominated.	Noted
SSE Power Distribution	Yes, provided the observed data is readily available. What is the process if this data is not available?	Noted
NPG	Yes we agree with this change to the legal text. To keep the scenario realistic, the historical maximum generation output should be used - however, this should be revisited yearly to ensure that any increases in maximum generation output are captured in the model.	Noted
UKPN	Yes, we agree with this change in the legal text as it will allow the DNO to allow for contracted generation capacity that is not being exported onto the network.	Noted
Good Energy	We agree this is an improvement to the previously proposed legal text, but consider it should refer to the observed maximum generation export rather than the observed maximum generation output.	The group discussed this comment and suggested that rather than using the word “export” it should be “exported”.
RWE	No comment	Noted
SP Distribution & SP	Yes, this will help ensure that customers generation tariffs reflect what is “actually” happening on the network and not what “could” happen.	Noted

Manweb		
WPD	Yes	Noted
GTC	No comment	Noted
Company	**Question Nine** ***- The CP introduces six new CDCM tariffs and thirty-six LDNO discounted tariffs. These additional tariffs could impact the use of other industry data and systems, for example line loss factor classes used in settlement. Do you foresee any issues with the implementation of the additional tariffs?***	**Working Group Comments**
CLP Envirogas	No comment.	Noted
ENWL	We do not see any implementation issues with the introduction of this change proposal for Electricity North West.	Noted
SSE Power Distribution	Where DNO/IDNOs have embedded networks in other DNO areas, spare LLFCs may be lacking.	Noted
NPG	As a consequence of the new tariffs, there will also be new LLFCs created and it will be necessary to migrate to a new LLFC over time as primary substations move from low GDA – medium GDA-high GDA. Ensuring that customers are migrated correctly when the threshold is reached may be problematic (especially as customers will lose credits at 2.5 years and 7.5 years). The number of LLFCs available in settlements is known to be an issue, (999 per licence) particularly for IDNOs. Consideration needs to be given to how this will be addressed if there are several changes approved which require new LLFCs. DCP 179 is currently under development and will require DNOS to create new LLFCs. The working group should consider an RFI to ensure DNOs have sufficient available LLFCs.	The Working Group observed that other DCUSA DCPs are resulting in additional LLFCs needing to be used and the issue is likely to become increasingly problematic over time. The number of LLFCs available may need to be addressed by another group. With regards to DCP 137, the impact is unlikely to materialise in the short term, as although six new DNO tariffs will be introduced it is about whether there are any HV customers on IDNO tariffs connected to a Generation Dominated Area. It is unlikely that there will be thirty-six (i.e. all IDNO tariff combinations) of these types of customer in any IDNO areas in the short term. In the longer term, the currently ongoing settlement reform work may mean

		that the number of LLFCs available is removed as an issue. OD took an action to check on what is being done within other working groups in terms of this issue. A BSC change would need to be brought forward to introduce additional LLFCs. It was observed that as it would currently stand it is likely that the costs of implementing the BSC Change would outweigh the benefit of introducing the generation dominated area proposal.
UKPN	We do not foresee any problems with the additional tariffs.	Noted
Good Energy	We have previously experienced difficulties with the application of LLFCs to generators and have had to bear unexpected additional costs when LLFCs have been corrected retrospectively after monthly invoices have been settled. This will be even more important to an embedded generator claiming a FIT/CFD as their payment will be based on loss adjusted export. A response to the previous consultation indicated that some DNOs would be unable to accommodate the additional number of LLFs required.	Noted
RWE	No comment	Noted
SP Distribution & SP Manweb	No	Noted
WPD	No	Noted
GTC	As an LDNO we operate over 14 GSP groups with only 999 LLFCs available. We are not sure whether we would need to replicate all LLFCs. In an extreme example we would need 42 (36 +6) X14 LLFCs This gives a total of 588. We do not have sufficient spare LLFCs to facilitate this.	The Working Group noted that in the short term the group does not believe that all LLFCs, if any, would need to be replicated.

	Therefore we cannot support this solution as being cost effective at this time	However, see note above regarding BSC changes.
Company	**Question Ten - *Do you agree that the demand growth rate of 1% should continue to be used? If not, how should this value be forecast?***	**Working Group Comments**
CLP Envirogas	We do not believe that forecast should be used, we would prefer the use of actual data. If forecasts are to be used, then these should be a best estimate and there appears to be no rationale for using a generic 1%, we suggest using the growth forecasts provided by each DNO for its specific network area.	The Working Group has noted in previous comments about the use of actual data. The 1% demand growth is an excepted long term demand growth used within the charging methodology and it reflects the rate of demand growth that has been seen in the longer term.
ENWL	Yes, this value is consistent with the assumption used within the EDCM and more representative of the long term average.	Noted
SSE Power Distribution	Yes. This is a pragmatic approach. It can be reviewed in the future.	Noted
NPG	Yes this is a sensible value and is used elsewhere in the industry. However, each DNO should also review the actual generation growth and if there is a significant variance from this then a separate DCP should be raised to vary the 1% (to an average of all 14 licence areas) and this should be reviewed yearly.	Noted
UKPN	We believe that it is appropriate to continue to use the notional 1% demand growth rate. This is consistent with the growth rate used for other charging purposes.	Noted
Good Energy	No, if the generation growth rate used is for the ED1 period the demand growth rate used should also be for the ED1 period. If a long term demand growth of 1% is used the generation growth rate should also be a long term view. There must be consistency between the demand and generation growth rates.	The Working Group noted that generation growth reflects new technology far more than demand growth does, therefore, the Working Group feels that it is appropriate to use long term demand growth against more recent forecasts of generation growth.
RWE	Under RIIO-ED1 DNOs have worked up forecasts of the take-up of demand technologies such as electric vehicles. It appears odd that while generation is based on forecast models, demand growth is based on an arbitrary status quo fixed figure.	See above comment
SP Distribution	As the demand growth rate of 1% is used in EDCM, this should be consistent throughout all the charging methodologies. From applying DNO specific demand growth rates and	Noted

& SP Manweb	comparing the outputs to the 1% growth rate, it appears that this input has minimal impact on the calculation.	
WPD	Yes	Noted
GTC	No comment	Noted
Company	**Question Eleven - *If DCP 137 is approved, is the proposed implementation date of 1 April 2015 acceptable? If not, please provide your preferred implementation date and supporting rationale.***	**Working Group Comments**
		It is the view of the Working Group that the target implementation date of April 2015 is achievable but note there is a potential issue with the settlement systems and the restriction of Line Loss Factor Classes, the impact of which needs to be understood. The Working Group noted that there may be an interaction with DCP 178 regarding the 15 month notice period that DCP 178 seeks to introduce.
CLP Envirogas	We do not think that DCP 137 should be approved in its current form.	The Working Group noted the respondent's view.
ENWL	We support the implementation date of April 2015.	Noted
SSE Power Distribution	Yes	Noted
NPG	This date is achievable provided a decision is received in a timely manner to allow inclusion in indicative charges in December - i.e. by the end of October 2014. However, it may be more prudent to move this to April 2016 to allow for the change to be communicated to customers in advance to ensure that there is sufficient time for those affected to alter their revenue forecasts.	Noted
UKPN	The proposed implementation date is acceptable.	Noted
Good Energy	No, if it is approved implementation should be deferred until 1 April 16 at the earliest to give industry participants and generators more notice of the change and to facilitate migration of generators to new LLFCs well before implementation. We have previously experienced	Noted

	difficulties with the application of LLFCs to generators and have had to bear unexpected additional costs when LLFCs have been corrected retrospectively after monthly invoices have been settled.	
RWE	There needs to be sufficient time to communicate the change to generation customers and for them to factor the change in credits in to annual business plans.	Noted
SP Distribution & SP Manweb	Yes, this impact of this change is that some generators will see a reduction in their credits, but given these credits are for supporting the network it is more appropriate to ensure that this change is in place as soon as possible to improve cost reflectivity.	Noted
WPD	No, the amount of extra working in initially setting this would mean implementing this for April 2015 would be impractical and it should be April 2016 at the earliest or April 2017 if DCP 178 is approved.	Noted
GTC	We do not support the change. But if it was approved we may need to raise a change to settlement systems to allow more than 999 LLFCs. If this was the case we do not think the BSC and parties to the BSC would be able to accommodate such changes in such a short timescale. The stress on the availability of LLFCs needs to be considered in junction with changes to bring PC5-8 customers into a new HH measurement class (P300 in BSC).	Noted
Company	**Question Twelve** - ***Are there any unintended consequences of this proposal?***	**Working Group Comments**
CLP Envirogas	The creation of further uncertainty for distributed generators – those already operating and those considering investment.	Noted
ENWL	We are not aware of any unintended consequences of this change proposal	Noted
SSE Power Distribution	Not currently aware of any.	Noted
NPG	As per paragraph 6.5 - The Working Group also noted that ‘refunds’ of credits should not be paid in future years if it is established that the generation dominance of any primary substation did not materialise. We note that the working group have suggested that no rebates will be given. However, it would not be fair or equitable for a generator at a non GDA primary that was never forecast to become GDA to receive credits, conversely, whilst a generator at a primary that was forecast to become GDA but never did would not receive credits nor would they receive a “rebate”. This change introduces an additional level of complexity and uncertainty to the CDCM	The Working Group noted that a substation may cease to be generation dominated because of the affect that it had been previously classified as generation dominated and this causing the desired effect or reducing generation. It was observed that refunds where a substation ceases to be generation dominated will not be applicable. This is

	charging model which currently has average charges for most customers and introduces semi-site specific tariffs for this group of customers. It is also potentially at odds with the current desire for simpler more transparent, predictable charges. We believe there is a real risk of customers changing tariffs year on year depending on whether or not the reinforcement actually goes ahead and it has the potential to creates some significant billing/refund issues between DNOs/Suppliers and end customers.	because the reason you are paying credits is to remove the need to reinforce. Charges are based on creating incentives to behave in ways that will reduce network costs using forward looking approach.
UKPN	We have not identified any unintended consequences of this proposal that have not been addressed during the development of the solution.	Noted
Good Energy	If any DNO is unable to accommodate the additional number of LLFCs required without an increase in their total number of LLFCs to above 999 there could be far reaching unintended consequences of the proposal.	Noted. See earlier response regarding LLFCs.
RWE	No comment	Noted
SP Distribution & SP Manweb	This change proposal will also introduce additional complexity thus reducing the transparency of the calculated generation tariffs. The tariffs are also dependant on forecast data that may or may not materialise, there could be an increase in volatility of the charges year on year (given DNOs will be required to review the substations list annually). Some customers may find that the primary substation they are connected to had been identified as likely to become generation dominated in one year, receiving a reduced credit, then the forecast may change the following year where this is no longer the case, this could leave some customers feeling unfairly charge and visa-versa.	The Working Group noted the first two paragraphs of this response. With regards to the third paragraph, the Working Group notes that this could be a consequence of the methodology but does not believe that it is positive or negative in its effect, in that it reflects conditions at the primary substation.
WPD	No	Noted
GTC	See above	Noted
Company	**Question Thirteen - *Do you consider that the proposal better facilitates the DCUSA objectives?***	**Working Group Comments**
CLP Envirogas	We do not believe that this change discharges Charging Objective 1 and General Objective 3. Whilst it is a review of the charging methodology, it does not improve the methodology. The change does not encourage competition (General Objective 2). This does not result in a cost reflective charging methodology (Charging Objective 3) as it is based upon forecasts. A generator providing near perfect support for the network at about	The Working Group noted that it had previously discussed these topics against earlier responses. The use of forecasts is part and parcel of the

	the point of equilibrium is penalised on the basis of reinforcement that may be needed (and paid for) due to the introduction of an incremental generator at the primary substation. It would be more cost reflective if based upon the actual position and actual data on an annual basis. We do not believe that it results in less expenditure by the DNO or more efficient networks (General Objectives 1 and 4). The ongoing GDUoS credits are generally not a predominant factor in a distributed generator's location decision – such ongoing income/costs are not well publicised by the DNO when requesting a connection offer. Of far more relevance is the availability and cost of land, ongoing "fuel" and labour, planning permission and the capital cost of a network connection. Neither do we believe that it satisfies Charging Methodology 4 as it takes account of forecasts rather than actual developments.	charging methodologies and considered good business practice.
ENWL	We believe this change proposal will result in more cost reflective charges for generators and reduce the incentive on generators to locate in areas where they may drive reinforcement. Consequently this CP better meets charging objectives 3 and 4 and general objective 1.	Noted
SSE Power Distribution	Yes	Noted
NPG	Charging Objective One – Yes –a common methodology will result in consistency and also transparency of process. Charging Objective Two – Yes – The commonality of approach towards HV generators will assist in the facilitation of competition , however, it could also been seen as a barrier to connecting generation. Charging Objective Three – Yes –as there will not be credits given to generators who have actually caused a cost to be incurred by the DNO, but could result in inefficient/disproportionate costs being incurred to manage a few customers Charging Objective Four - Yes – a review of generation growth and load growth, carried out on a yearly basis will ensure that changes in the actual license area will be captured in the model. General Objective One – Yes, this new approach will ensure that credits are not given to generators who have caused the DNO to incur a cost. General Objective Two – Yes, commonality and transparency will assist in the facilitation of	Noted

	competition, however, it could also been seen as a barrier to connecting generation. General Objective Three – Yes, a common model used by every DNO based upon a common methodology will enable compliance with distribution licenses , but could result in inefficient/disproportionate costs being incurred to manage a few customers	
UKPN	Yes, we consider that charging objective 3 is better met with this proposal.	Noted

Good Energy	a) We consider the proposal is detrimental to CDCM Objective 1 and General Objective 3 because:
	• the introduction of locational tariffs for generation but not for demand discriminates unfairly against generators;
	• it is an undue complication of the current CDCM which is unwarranted bearing in mind:
	    o the issues it creates for suppliers, mentioned in b) below, in forecasting of generation charges and their increased volatility;
	    o the number of generation dominated areas, at a national level was reported by the MIG GDA Sub group to be less than 5% and is still shown in this change proposal to be less than 5%, having grown by only half of 1% over 2 years.
	
	b) We consider the proposal is detrimental to CDCM Objective 2 and General Objective 2 because:
	• it would become very difficult for suppliers to forecast generation charges as they would not know (i) when a primary is likely to move between the charging bands or (ii) which primary a generator was connected to when they contracted with the generator;
	• tariffs would become more volatile due to generators being switched between charging bands year on year and with potentially little warning.
	
	c) We also believe the proposal is detrimental to General Objective 1 because it would be difficult for DNOs to give accurate indications of which tariff band would apply to a generator. If they received requests for the applicable tariff band from several generators in a year and
		It was noted that comments around discrimination had been addressed against an earlier consultation response.
		
		The Working Group appreciates that the current status of generation dominated areas may be seen as being immaterial but the Working Group feel that the change will better meet the DCUSA objectives in the round.

	all of the connections proceeded it could move the primary into a higher generation dominance band. If the DNO treated each request in isolation it could understate the applicable charges; however if they assumed all enquiries would go ahead then it could deter generation connections unnecessarily. We understand this issue has already been encountered with the EDCM.	
RWE	It is not clear that the statement that 'charges can be reasonably expected to be incurred' by DNOs can be supported when the charging under this proposal would be based on long term forecasts, with high uncertainty.	The reason that a long term forecast is being used is that this removes the uncertainty that short term forecasts would provide. For example, year on year growth would be a lot more uncertain.
SP Distribution & SP Manweb	Yes, we agree with the working group's views that this proposal better facilitates Charging Objective one & four and General Objective three. The working group also it could be argued that this proposal may also reduce competition given that it adds further complexity to calculating and passing on the charge, thus acting as a barrier to entry.	Noted
WPD	This change improves how DNOs meet the General and Charging objectives by rewarding customers (generators) that are supporting the network and reducing or removing that reward where that benefit is reduced or the generation is detrimental to the network i.e. it causes the need for reinforcement.	Noted
GTC	We still remain to be convinced that this change is more economic and efficient and that it will lead to more cost reflective charges and thereby better facilitate competition. In particular we are not convinced that the impact on embedded networks has been fully considered and assessed	Noted
Company	**Question Fourteen - *Are there any alternative solutions or matters that should be considered?***	**Working Group Comments**
CLP Envirogas	The use of the actual generator demand balance on an annual basis in conjunction with publicised historic trends and movements, together with accepted and open connection offers.	The Working Group observed that the DCUSA Charging Methodologies are currently based on forecasting long run costs and not on actual accounts based costs. The purpose of this is to provide a signal for driving efficient use of the network.

ENWL	No	Noted
SSE Power Distribution	No	Noted
NPG	Not at this time.	Noted
UKPN	We have not identified any.	Noted
Good Energy	There is no need for the proposal or the consideration of any alternative solutions, bearing in mind that the number of generation dominated areas, at a national level was reported by the MIG GDA Sub group to be less than 5% and is still shown in this change proposal to be less than 5%, having grown by only half of 1% over 2 years.	It was noted that the CP must be assessed based on whether it better meets the DCUSA objectives.
RWE	No comment	Noted
SP Distribution & SP Manweb	Not at this time	Noted
WPD	No	Noted
GTC	No comment	Noted
Company	**Question Fifteen - *Do you have any further comments?***	**Working Group Comments**
CLP Envirogas	No further comments.	Noted
ENWL	No	Noted
SSE Power Distribution	No	Noted
NPG	Not at this time.	Noted
UKPN	No	Noted
Good Energy	No	Noted
RWE	No	Noted
SP Distribution & SP Manweb	We would like to note that the overall impact on the changes as a result of this change are minimal, and this change relies upon suppliers passing on this change in charge to the customer so the customer received the locational cost signalling and incentive the customer to efficiently use the network. However this may become increasingly important as the networks develops overtime.	It was noted that the CP must be assessed based on whether it better meets the DCUSA objectives.
WPD	No	Noted

GTC	No comment	Noted