



**Scottish Power**  
**Energy Networks**



**SSE Power Distribution**

**e.on**

Central  
Networks

**Structure of electricity distribution charges**

**Summary of responses to Joint  
consultation on the longer term charging  
framework**

*July 2007*

## Summary

Scottish Power Energy Networks, Scottish and Southern Energy Power Distribution and Central Networks are working together as the 'G3' to explore the possibility of developing a new charging methodology based on work carried out jointly by all DNOs during 2006.

G3 issued a consultation paper in May 2007<sup>1</sup> and a total of twelve responses were received. Of these responses: 1 was from Energywatch, 4 were from electricity suppliers, 1 was from a electricity generator, 2 were from electricity distributors, 1 was from a electricity industry trade association, 2 were from specialist consultants and 1 marked confidential from an EHV customer.

Whilst there was in the responses some support for the proposed G3 methodology, there were also some concerns. This paper summarises these responses and includes G3 comments where appropriate and details the next steps in the G3 process.

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<sup>1</sup> This paper is available from the Energy Networks Association's website - <http://2008.energynetworks.org/consultations-regulation/>

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# 1. Introduction

- 1.1 Following completion of the joint DNOs work under the Energy Networks Association's Commercial Operations Group (COG) at the end of 2006, Scottish Power Energy Networks, Scottish and Southern Energy Power Distribution and Central Networks agreed to work together as a group known as 'G3' to further develop the work of the joint DNOs and to create a new methodology for use of system charges.
- 1.2 In parallel to this, G3 presented updates about its work at the Distribution Charging Methodology Forum<sup>2</sup>.
- 1.3 In addition to the presentations at the DCMF, G3 held a public workshop on 13<sup>th</sup> June 2007. This workshop was well supported by a range of industry parties and attracted helpful comment from participants.
- 1.4 To ensure wide and relevant circulation the consultation paper was also notified to EHV customers.
- 1.5 G3 have also met informally with Ofgem to update progress and seek guidance to help with the new methodology submission due in September 2007.
- 1.6 This document follows the structure of the consultation paper and sets out the responses received against the various questions raised in each section, together with other responses also received and captured here as "general" responses.
- 1.7 Responses are available on the ENA website.

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<sup>2</sup> The DCMF is being established by the ENA Commercial Operations Group as a forum for the industry to discuss distribution charging matters. It will consist of DNO, IDNO, supplier, customer, generator and Ofgem representatives. Details of the meetings are available from the ENA web site - <http://www.energynetworks.org/spring/regulation/index.asp>

## 2. General comments

| General comments   |   |
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| Consultation response  | G3 comment  |
| <p>Energywatch responded that:</p> <p>Consumers, particularly the vulnerable, expect network operators to deliver safe, secure, and reliable electricity supplies in an efficient and economic manner. However, the vast majority of consumers, who, through their suppliers, use the distribution networks, are passive recipients of network services. The ability of existing users to respond to locational pricing signals based on where they are connected on the networks, either individually or collectively, is non-existent. For users, DUoS charges must also display the characteristics of simplicity and transparency – the derivation of charges should be easy to understand and accessible. Other long-term considerations also need to be taken into account, not least how to develop actively managed, responsive networks which can accommodate more distributed generation. They are concerned that DNOs are concentrating too heavily on their licence obligation to develop cost reflective charges. The DNOs must consider how to balance the impact of cost reflectivity against other licence obligations, not least facilitating competition in generation and supply. It is unacceptable for consumers to be subject to the prospect of higher bills as a result of cost reflective DUoS charging when the significant increases in wholesale costs which have fed through to retail bills over recent years have only recently begun, somewhat modestly, to be reversed. If there are significant tariff disturbances for the majority of consumers, these must be subject to phasing over an appropriate period of time. They continue to support the retention of the DRM pricing model for deriving DUoS charges as it best reflects the simple, predictable, certain and transparent method we consider appropriate.</p> | <p>G3 understand the concerns some stakeholders have on the ability of customers to respond to locational charging signals. Our proposals only envisage locational signals for customers connected to the EHV network.</p> <p>Our proposals attempt to address the concerns raised by retaining the simplicity of the charging structures and are designed however to address the issue of distributed generation which our current models do not do adequately.</p> <p>We have a licence obligation to develop cost reflective charging and believe that this is consistent with our other licence obligations not to distort competition in electricity supply, generation or distribution.</p> <p>The total charges are governed by the allowed revenue. However, it is recognised that introducing a new methodology may result in tariff disturbances for HV and LV customers. The effect of this is being reviewed.</p> <p>G3 believe that the DRM is not sufficiently transparent and is not designed to accommodate distributed generation without further development.</p> |
| <p>A generator responded that:</p> <p>Document is not bed time reading and it is very difficult to understand from a customer point of view.</p>   | <p>We recognise that the document raises complex issues that may be difficult to understand for those who are not closely involved in these activities. We have however responded to comments made previously that</p>  |

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|   | <p>stakeholders wish to be involved in the process for developing revised charging methodologies and have encouraged participation through our public workshop, DCMF presentations and the consultation paper.</p>   |
| <p>A generator responded that:</p> <p>They struggled to understand the meaning of "customers modifying their behaviour"</p>   | <p>The objective is that customers will react to economic charging signals by, for example, changing their pattern of use, hence facilitating cost effective investment in electricity distribution infrastructure.</p>  |
| <p>A trade association responded that:</p> <p>They are pleased to offer its comments on this consultation by a grouping that represents six of the fourteen distribution network areas in Great Britain. They particularly appreciate our attempt to work together as this will result in fewer different methodologies for developers to understand. Before responding to the some of the specific questions asked they made two general points. Firstly, it is important to consider the charging structure in the long term and therefore it is unfortunate that the G3 feel constrained to make it fit into the price control arrangements that are set to expire in 2010. In particular the separate price control allowance for generation makes the G3 feel constrained to disallow negative charges for generators that defer the need for reinforcement (paragraph 5.26 of the consultation) on the grounds that this would necessarily impose costs on other generators. This trade association say that obviously they consider the result to be undesirable and they consider it would be helpful when considering the methodology to produce the indicative charges that would apply without this restriction. Paragraph 2.16 of the consultation states that "The DNOs acknowledged that choice of a revenue reconciliation method or methods is vital to ensuring minimal distortion of marginal costs." As the reason for this is to provide the maximum influence on those parties that can take note of the price signals, it would seem logical to minimise the distortion of marginal costs for such parties. They favour a Ramsey pricing approach, or perhaps for simplification, applying no distortion to certain categories of connectees, such as generators. It is clearly acknowledged that well-</p> | <p>We are encouraged by this response and believe that DNOs should cooperate in developing methodologies which will assist all stakeholders in understanding and commenting on approaches as they are developed.</p> <p>We note the point on long term charging structures and the price control and we believe that identifying costs should not be impacted by price control treatments. However, the charges resulting from the costs identified in the methodologies need to reconcile to price controlled revenues and these must therefore reflect the current arrangements. If the price control changes in the future then the approach to revenue reconciliation will need to be reviewed accordingly.</p> <p>We remain committed to an approach that minimises distortion of the marginal cost signals, is fair, cost reflective and does not penalise those customers unable to respond (see comments above by Energywatch).</p> <p>In relation to the request of seeing the effect of removing the cap for negative charges, the G3 is currently analysing the effects and materiality of doing this and</p> |

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| <p>located, new generation will actually save future investment and this should be reflected in charges, (as should demand in “generation full” areas).</p>   | <p>will provide more information when submitting the modification request.</p>  |
| <p>A supplier responded that:</p> <p>They have continually pressed for illustrative impacts to be provided in this series of consultations around enduring structure of charges, and they welcome the fact that the G3 group has endeavoured to provide such illustrative charges. This is a helpful approach and we hope other DNOs will learn from this approach. They acknowledge the caveats included in respect of the charges being indicative only and subject to further work, but they note with considerable concern, that the overall pattern is for Domestic unrestricted charges/smaller I&amp;C charges to increase, in their view significantly, and for larger I&amp;C charges including HV charges to decrease. There are some exceptions to this, but for the most part the pattern holds true. As a major domestic supplier, they believe that it is a matter for serious concern that the application of these methodology changes may result in a reasonably significant transfer of additional costs onto domestic customers. In their view, this is completely unacceptable. Given the group’s comments that these indicative charges are very much a work in progress, they trust that this inequity will not persist into the final charges. In addition, whilst they acknowledge that frequent and detailed consultations have taken place, they are concerned that there is limited evidence that respondent’s views have been fully taken into account, in particular, suppliers’ repeated requests for transparency and predictability of the resulting charges.</p> | <p>We have acted on comments provided to the joint DNO work that stakeholders wish to see illustrative charges at an early stage, though this could indicate tariff disturbance that may not arise in final proposals. We are analysing the illustrative results to fully understand what is driving the cost disturbance to ensure that the approaches are truly cost reflective.</p>  |
| <p>A supplier responded that:</p> <p>They welcome the opportunity to respond to the G3 consultation on charging methodology. They acknowledge that the apportionment of use of system costs is a matter of great theoretical controversy where a number of different approaches are possible. Each, no doubt, has pros and cons. As a supplier their primary concern is the impact on customers. Regulatory intervention has frequently been the cause of instability in use of system charges which leads to price disturbances. More often than not, these price shocks have not been anticipated. In the short term</p>  | <p>We note the concerns and agree that predictability and stability are important from a suppliers’ perspective.</p> <p>Before any methodology change is put forward we will need to be fully satisfied that the proposals are more cost reflective than our current approaches. Any tariff disturbances will need to be due to a better understanding of the costs in supplying different types of customer. If the tariff disturbances are significant we</p> |

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| <p>this has given suppliers difficulty in managing margins. In the long term, this leads to additional risk premiums in supply prices which operate against customer interests. They hope that G3 methodology will be applied in a pragmatic way with a view to minimising volatility and maximising predictability. They would also like to see a forward looking view on price structures that leads them on a logical path to the type of approach that will be required when smart meters are rolled out.</p> | <p>will ensure that customers are given plenty of notice.</p>  |
| <p>A supplier responded that:</p> <p>In relation to the Regulatory Reporting Pack (RRP) – how transparent is the process when making use of the RRP as Suppliers are unable to see the contents provided by DNOs when completing the template. Suppliers need to see this information to be in a better position to assess the models being developed and their associated outputs.</p>   | <p>We accept that the RRP is not generally visible at present, but it can at least be used by Ofgem at the time of submission of Indicative and Final tariffs to check that these are in accordance with the methodology (i.e. Ofgem can confirm that RRP figures have been adhered to if that is an explicit part of the methodology).</p> <p>We are considering whether more complete data can be placed in the public domain.</p> |

### 3. Forecasting future reinforcements

| The different approaches to demand and generation.  |  |
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| Consultation response   | G3 comment   |
| <p>A distributor responded that:</p> <p>They believe that it is appropriate to use the same treatment for demand and generation wherever possible. The main reason given by the G3 for treating EHV generation differently to demand is because of the lumpy nature of the growth. This is also a characteristic of EHV demand growth and highlights a fundamental inconsistency.</p> | <p>For EHV networks we are in effect modelling load flows down to the 11kV bars at primary 33/11 kV substations, that is, we are not just considering the EHV loads but a much broader demand base. Hence there is no inconsistency as implied.</p>  |
| <p>A distributor responded that:</p> <p>They do not believe that it is appropriate to apply different methodologies for determining the costs attributable to demand and generation. This is a fundamental principle for the equitable treatment of demand and generation.</p>  | <p>At present we believe the proposed model is cost reflective because it mirrors the discreet nature of generation connections into the foreseeable future and in particular it captures the effects of fault level considerations.</p> <p>When generation begins to proliferate and become omnipresent like demand, then the underlying parameters of the methodology can be reviewed to reflect future reality.</p>               |
| <p>A trade association responded that:</p> <p>One has to be very careful about the different approaches to modelling demand and generation. The consultation document appears to assume that all generation will be large and lumpy, and all demand small and non-lumpy, whereas this is not necessarily the case.</p>  | <p>The methodology assumes that EHV and HV generation is in discrete sizes as modelled by the test size generator. Unlike demand, generation is not charged the marginal costs at higher voltage levels. Thus the less lumpy LV generators are not charged for marginal costs based on the lumpy model at the EHV level. This can be refined if distributed generation begins to manifest itself and more evidence is available.</p> |
| <p>A supplier responded that:</p> <p>They consider it is reasonable to use a different approach for demand and generation, given the different impacts on the network. They also agree that the approach should not discourage the</p>  | <p>We are pleased to see agreement with our approach to demand and generation, and that the supplier agrees with us that generation should not be discouraged where it can be connected at zero reinforcement</p>  |

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| connection of generation where this can be achieved at zero cost.   | cost.   |
| <b>Is analysis at the Network Group level appropriate?</b>  |   |
| <b>Consultation response</b>  | <b>G3 comment</b>   |
| <p>A supplier responded that:</p> <p>In relation to Network Group Level, recent experience has shown that determining appropriate group levels can be tricky.</p>   | <p>Network Groups are currently the fundamental basis for network planning and analysis.</p> <p>Where networks have reasonable interconnection then the combined network entity is considered as the relevant Group.</p>  |
| <p>A distributor responded that:</p> <p>The use of network groups is the source of two problems. The first is the possibility of disturbance in prices where a group of customers is moved between network groups and the second is the difficulty of applying the principle to heavily interconnected networks. They believe that both of these are significant drawbacks to the method.</p> | <p>In our experience it is not the case that customers are exchanged between groups with any regularity. In those rare occurrences exchanges will be at the lower voltage levels of the network where geographical peripheral issues may necessitate this, but it is here that standard tariffs apply.</p> <p>If two networks are heavily interconnected then the Group will consider both networks as a single entity.</p> |
| <p>A trade association responded that:</p> <p>They think that the Network Group level of analysis is appropriate in the majority of cases but may need to be modified for areas of the network, e.g. where the next reinforcement may be to operate interconnected with another group or reinforce and split up a group that is currently run as such.</p>                                    | <p>The response generally in agreement with the G3 approach. In our experience the suggested events of re-grouping are very rare.</p>   |
| <p>A supplier responded that:</p> <p>Given the complexity involved, a degree of aggregation seems to be a reasonable approach, providing there is still adequate transparency and predictability of the end charges.</p>  | <p>This respondent supports our methodology aim of transparency (LTDS) and experience of stability in Network Group configurations.</p>   |
| <b>Is the approach of incrementing demands in 1% steps up to 15% and undertaking contingency analysis at each step reasonable?</b>  |   |
| <b>Consultation response</b>  | <b>G3 comment</b>   |
| <p>A distributor responded that:</p>  | <p>An important aim of the G3 methodology is to optimise the</p>  |

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| <p>They believe that the use of a long run growth rate is appropriate for assessing long run costs.</p>  | <p>use of the network and network investment over an intermediate period of about 10 years for which credible load growth forecasts can be projected and which allows enough time for customers to respond. There is no single growth rate which characterises growth over the whole network. Some parts are in decline whilst others are likely to experience significant growth.</p> |
| <p>A distributor responded that:</p> <p>It is likely that in some circumstances the capping of the demand increment at 15% will not replicate the growth on a network group.</p>   | <p>The 15% growth, together with the 10 year horizon, are not magical and immovable numbers. However in our collective G3 experience 15% is sufficiently reflective of potential growth looking forward at present across all our Network Groups. In any case it is something that can be kept under review from time to time.</p>   |
| <p>A trade association responded that</p> <p>Incrementing demand in 1% steps clearly represents the effect of demand growth at HV and LV rather than new EHV demand connections.</p>   | <p>On EHV network load flows we are also modelling loads at the 11kV bars of networks at the lower voltages.</p>   |
| <p>A supplier responded that:</p> <p>Again, whilst not having sufficient technical expertise to fully evaluate the proposals, incrementing demand in steps and testing at each level is an established approach to assessing network requirements. The proposal seems reasonable, but they would welcome further information on the basis for concluding that 15% above current maxima is sufficient, and the confidence levels the group have around that conclusion.</p> | <p>The 15% is no magical number but reflects combined G3 experience across our networks and over a number of years. This will be reviewed periodically to confirm it is a valid assumption.</p>  |
| <p><b>Is one year of actual cost data sufficient to produce forecasts for HV and LV reinforcement costs?</b></p>   |  |
| <p><b>Consultation response</b></p>  | <p><b>G3 comment</b></p>   |
| <p>A supplier responded that:</p> <p>Before being in a position to answer this question it may first be necessary to fully understand how volatile one years' data may be, either within year</p>  | <p>In our attempt to be transparent it was always our intention to reflect case history as RRP data builds up over time. However we will consider further whether it is possible to address this.</p>  |

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| <p>or by year-on-year comparison. Is the intention to make use of an average years' data or to use the most recent year? Averages change less over time and may therefore prove more stable and so reliable for use within a Charging Methodology. In addition, year-on-year trends may provide a more suitable 'context'</p>   |   |
| <p>A distributor responded that:</p> <p>Using a single year's data as the basis for forecasting is unreliable and will likely deliver a greater volatility in charges than using several years' data.</p>   | <p>We accept and will look into it at this stage.</p> |
| <p>A supplier responded that:</p> <p>As previously stated, they are not experts in the forecasting of demand/costs on electricity networks, but they believe that one year's worth of data would normally be a very short period on which to base forecasts for future years. They would welcome clarity on the analysis that G3 have done to enable the conclusion that a single year's data is a sufficient and robust basis.</p> | <p>We accept and will look into at this stage.</p>    |

## 4. Determining forward looking costs

| The approaches to determining demand and generation marginal costs.   |   |
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| Consultation response   | G3 comment  |
| <p>A generator responded that:</p> <p>It looks like existing generation would be retrospectively asked to contribute to future growth in the system via annual use of system charging. This could force smaller generators to shut down earlier than expected, or even stop projects as they will not be able to model a connection cost over a time period, especially in marginal profit work (for example they start on landfill with a 300kw set as the lowest financially viable sized unit to install on a new site). If their running costs are not consistent and could be ramped up due to other connectees coming along, it would likely be a non starter. Embedded generation can have a major effect on local network voltages etc and needs to be judged individually to see if it is beneficial. As an embedded generator, again they think this statement ignores a great many smaller generation schemes which when totalled up are very significant, and at a local level are very significant in their effect on the network. A hint at connecting generation at no cost is a bold statement, is this at no cost to the embedded generator, or the DNO?</p> | <p>This is a recognised issue and arises from the application of ‘shallowish’ connection charges along with GDUoS, which is intended to encourage equitably demand and generation.</p> <p>Marginal costs for HV and LV generation reflect the average cost across the whole network. Therefore these will not be significantly affected by the presence of other connectees locally.</p> <p>Cognisance is taken of the amount of generation contribution allowed for by P2/6 and is therefore consistent with how Planners analyse and reinforce networks.</p> <p>When generators connect in areas where the network can accommodate them there is no marginal cost to the DNO for reinforcement of the network, which is what is being reflected in the FCP model.</p> |
| <p>A distributor responded that:</p> <p>The consultation places some importance on the selection of a priority list for assessing the appropriate reinforcement. At the recent workshop it was stated the use of an additional circuit was likely to cover almost all the first reinforcement requirements. Use of this option in a mechanistic way would reduce the complexity of the method, making it more transparent to users, and would reduce the scope for arbitrary decisions about the appropriate reinforcement.</p>   | <p>The FCP model already allows for a set of “mechanistic” rules for determining reinforcement, which indeed reduces subjectivity. However, the results of applying these rules are sense-checked in order to ensure they reflect reality and are therefore cost-reflective.</p> <p>Considering only the first reinforcement in each network group is not sufficiently cost reflective for some network groups as several reinforcements would be triggered within the proposed 10 year period.</p>   |

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| <p>A trade association responded that:</p> <p>The approaches to determining demand and generation marginal costs are not unreasonable in outline and they agree that a ten year look ahead period is an acceptable compromise between volatility and accurate forecasting. They also think that increasing the weighting attached to future reinforcement as it gets closer and therefore more certain, is the correct balance between reflecting the lumpiness of reinforcement and providing a degree of smoothing of charges over time.</p> | <p>We are encouraged by this response.</p>  |
| <p>A supplier responded that:</p> <p>It seems logical that the identical approach cannot be used on both demand and generation for calculation of marginal costs given the different impacts the two have on the network and the generally lumpy nature of generation investment. They found the description of the approach on LV clearer and believe that this seems reasonable, including a small LV generation benefit in return for offsetting demand.</p>  | <p>The current price control have separate allowed revenue for demand and generation (post April 2005 connections). Therefore 'demand allowed revenue' cannot be transferred and offset a benefit for generation hence the current capping to zero. So LV generation benefits would have to be paid for by other generators. However, in determining the generation net costs we take cognisance of the P2/6 benefit contributed by the generator.</p>  |
| <p><b>The time periods that should be used for determining costs.</b></p>  |   |
| <p><b>Consultation response</b></p>  | <p><b>G3 comment</b></p>  |
| <p>A distributor responded that:</p> <p>It is not clear why there should be costs spread over time periods other than the possible explanation that due to the uncertainty of the data this will add stability to the prices.</p>  | <p>Assigning demand marginal costs to the single time period of maximum demand can lead to instability, especially if the demands in other time periods are similar and fluctuating, as the charge rates could switch between time periods in an arbitrary manner. Thus there is a requirement for a band to resolve this potential situation. A significant instability can arise if 'peak' charges have encouraged demand to move off peak, as a switch in charges could cause suppliers and users to rapidly switch load back to the previous peak period. We believe our proposed method is</p> |

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|  | cost reflective and is aimed at providing a band matched to the growth rate and the cost recovery period.  |
| A consultant responded that:<br><br>It is the growth in the peak demand period which triggers the reinforcement expenditure, so the marginal costs in those other periods will be zero.  | See previous comment   |
| A distributor responded that:<br><br>The recovery period should be the same for demand and generation.   | The demand recovery period reflects the extended planning period, whilst the recovery period for generation is consistent with the price control cost recovery period. Although it may be desirable to have similar periods, there needs to be a sound basis for this.     |
| <b>Is the approach for determining growth rates, and particularly the method of adjusting for embedded generation to determine underlying demand growth, appropriate?</b>  |  |
| <b>Consultation response</b>   | <b>G3 comment</b>  |
| A supplier responded that:<br><br>It is important that the methodology reflects the value of embedded generation to a local DNO as embedded generation can defer the need to reinforce the network to support the requirement for increasing demand. They consider that the inclusion of negative charging in the methodology would reflect that value should be allowed. Negative Charging may also encourage siting of generation in areas that negates the requirement for reinforcement for future growth demand which will provide a benefit for all DUoS payers. | Earlier explanation refers to the benefit given to generation. At present G3 are looking into the effects of removing the cap.   |
| <b>Is the 10 year time horizon for considering network reinforcements and the associated cost recovery period a reasonable approach?</b>   |  |
| <b>Consultation response</b>   | <b>G3 comment</b>  |
| A supplier responded that:<br><br>They understand the 10 year horizon approach and agree that this seems a reasonable time period to adopt, but in order to be certain they suggest that sensitivity analysis is conducted at this relatively early stage in order gain the assurance required that this is a robust assumption. This could, for   | In arriving at the 10 year period G3 had considered that this best met our aspirations to be transparent and to be driven by creditable reinforcement schemes. It is beyond the normal planning period for which demand forecasts are made. Within the 10 year period some |

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| <p>example, take the form of running the model for 10, 15 and 20 years and quantifying the impact on the outputs obtained.</p>   | <p>network groups are subject to reinforcements that are sensitive to the particular pattern of growth and this will increase if a longer recovery period is used. However, reducing the recovery period spreads costs over a shorter period and leaves users less time to respond to price signals.</p>   |
| <p>Energywatch responded that:</p> <p>They query whether this approach would leave customers that connect much later at a distinct disadvantage.</p>   | <p>The charge rate would apply equally to all EHV customers in a particular Network Group. Late comers will be more able to respond to locational pricing signals.</p>   |
| <p>A supplier responded that:</p> <p>Essentially, in their view, there are two key questions: when do you reinforce and what capacity do you install when you reinforce? On the first, from a customer perspective, the investment should not be too early (or customers' money is spent before it is necessary) or too late. On the second, if too little capacity is installed, the DNOs will continually be carrying out small, probably inefficient, investments. If too much capacity is installed, again, customers' money is spent unnecessarily. Whilst overall a 10 year (or possibly 10-15 year) time horizon for considering network reinforcements does not seem unreasonable, they believe that this is too short a period over which to recover costs. They are of the view that the majority of costs should be recovered over the lifetime of the asset, whereas the document seems to suggest recovery in advance of the reinforcement. As distribution assets generally have a life of 40-50 years, then this would seem an appropriate timescale. Recovery "in advance" in this way, in our view equates to expensing capex, which they would not support in the case of capital investment. In turn, we believe that such a treatment of costs would place an unjustified burden on today's consumers.</p> | <p>Our methodology takes into account our obligation of designing an efficient network. In practice, the reinforcement is carried out when capacity is needed and using standard-size equipment.</p> <p>The overall cost does not depend on the cost recovery period as less plant is being paid for within a shorter recovery period. A longer recovery period would imply that customers start paying now for reinforcements required in say 20 years based on growth forecasts which are only valid for about a third of this time. Since the overall costs are the same, it is preferable to pay charges to cover the costs of the plant more likely to be required.</p> <p>The marginal cost methodology and the FCP methodology proposed are based on future costs. In practice current investment is considerably less than past investment and a large part of the allowed revenue arises from historic investments and depreciation. The aim is to levy charges to encourage efficient investment and use of the network.</p> |

**Should the 10 year cost recovery period used for demand be used for generation also, or should the 15 years assumed for generation in the distribution price control be used instead?**

| Consultation response  | G3 comment   |
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| <p>A trade association responded that:</p> <p>They agree with the approach taken to assessing charges for EHV-connected generators. As stated in paragraph 4.10 of the consultation, there is a need to ensure that generator connection is not discouraged if it can be achieved at no cost. It is important however to check that the methodology does not result in immediate positive use of system charges as soon as additional generation has used up the spare capacity.</p> | <p>If the generation headroom is used up, then it will result in positive use of system charges to give the message that further generation would require reinforcement.</p> |

**Should uniform generic values of the P2/6 contribution factors be assumed? If not, should they vary by type of generator or by region (taking account of the type of generator that is more likely to connect there)? Should actual contribution factors be determined from historical output data for existing generators where this is available? For lower voltage levels should voltage level averages be used?**

| Consultation response  | G3 comment   |
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| <p>A distributor responded that:</p> <p>They believe that generators should receive the appropriate P2/6 allowance in line with those that would be applied in the system design process.</p>  | <p>At the July DCMF this issue was debated at length and it was suggested that it is appropriate to adopt the P2/6 generic contribution factors for the time being. We will keep the matter under review as the generation debate evolves.</p> |
| <p>A distributor responded that:</p> <p>Where data is available, calculated contribution factors should be applied to generation connecting at any voltage levels.</p>   | <p>P2/6 guidelines facilitate this.</p>  |
| <p>A trade association responded that:</p> <p>In assessing the benefit of generation in deferring reinforcement the P2/6 factors are probably rather pessimistic. It could be argued that it would be more appropriate to treat generation at LV as negative demand, with perhaps a derating factor to account for the probability of the generation not being available during demand peaks. It is not consistent to use P2/6 derating factors when assessing the deferment of reinforcement, but not</p> | <p>See comment above.</p>  |

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| <p>when assessing the need for generator-driven reinforcement.</p>   |   |
| <p><b>Is the approach of using a typical generator size in determining the marginal cost appropriate?</b></p>  |   |
| <p>Energywatch responded that:</p> <p>DNOs should continue to assume average demand growth in the long term and plan network reinforcement accordingly. The scope and extent to which distribution generation may ramp up in the future is relatively unknown. The nature of actively managed and resilient networks should be to accommodate unexpected load growth, rather than prejudge potential levels of reinforcement which could occur.</p>  | <p>Forecasting embedded generation is difficult as growth is not generally uniform and tends to be “lumpy”. Generation growth is sparsely distributed at present and an individual generator represents a step-change. Hence, a “what-if” reinforcement approach gives a more realistic and appropriate forward looking pricing signal.</p> <p>G3 plan to provide more evidence of this behaviour in the G3 networks.</p>   |
| <p>A generator responded that:</p> <p>It is possible to predict where embedded generation will or is likely to occur in the future, ask your customers for their future plans! If this is kept strictly confidential, there is a pool of information readily available. Also, look at the trends in technology, exploration licences, landfill site locations, government financial incentives for generators; this information is out there. Also, reverse power will be an everyday feature of an active network, this should be being looked at and planned for now, not later. They have difficulty connecting in the north west because of an interconnected voltage group, the study work and method to allow us to connect at 11kv will take longer than the opportunity to generate.</p> | <p>When network is upgraded then these considerations should be taken into account.</p>   |
| <p>A distributor responded that:</p> <p>The generation prices are based on arbitrary decisions about the size and location of standardised generation reinforcement. The size of this standardised generator is based on historic data and not the likely size of generators connections in the future. The consultation document itself also comments that there are relatively small numbers of new connections. These are considered too few to determine location but seemingly sufficient to determine the key parameter of the standardised generator size. The</p>  | <p>New connection data is considered insufficient to determine either location or size. The standard size is based on existing generation and planned generation. Location is assumed to occur adjacent to the supply busbars as connection costs would cover most of the additional cost of any network reinforcement.</p> <p>The FCP demand methodology gives a zero marginal cost when growth falls to zero or below</p> |

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| <p>use of a standard generator size gives no forward looking cost message to a generator that increases the utilisation of a circuit but fails to exceed the circuit rating. This method is similar to the LRIC method in that it fails to give a locational marginal cost message when growth falls to zero or below. The forward looking cost element is only based on an accounting allocation of the costs allowed under the price control settlement.</p>   | <p>unless capacity is already exceeded. The generation charging methodology also gives a zero marginal cost when a capacity is adequate to install the test size generator, hence it does not fail to give a cost message as suggested.</p> |
| <p>A supplier responded that:</p> <p>When considering lower voltage networks, it would seem reasonable to base marginal costs on a typical generator, providing that enough data is available to be able to assess what a “typical” generator is in the circumstances. However, given the relatively limited number of generators connecting annually, and the apparent uncertainty around timing &amp; location, they are not sure a methodology can produce robust estimates for marginal costs. The document explains how a typical generator size is determined and the methodology for calculating this important factor seems broadly sensible. An enhancement to this calculation could include allocating a weighting to the three factors – previously connected generation, connections in progress and connection applications. They would suggest most weighting should be given to connections in progress as this should give the best insight into the future requirements of the networks, this seems to be borne out by the fact that the vast majority of new connections are connecting to the upper network.</p> | <p>Weighting would seem reasonable when there is a larger set of recent and proposed generators. This will be considered further.</p>   |

## 5. The G3 tariff model

| General  |   |
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| Consultation response  | G3 comment  |
| <p>A generator responded that:</p> <p>Section is not reader friendly if you are not involved in the DNO side.</p>  | <p>G3 have made the G3 tariff model available to anyone on request. Chapter 5 of the consultation should be read in conjunction with the tariff model for a clearer understanding.</p>  |
| <p>A trade association responded that:</p> <p>Their general view is that charges for generation should differ as little as possible from the identified marginal costs and therefore they will not comment in detail on the method of getting from the marginal costs to actual charges. They maintain for instance that in areas where there is an excess of demand over generation, refurbishment costs should not be attributed to generation as increasing amounts of generation would reduce the need for this refurbishment. They stated earlier that negative charges should be permitted but recognise that this would cause problems during the current price control period.</p>   | <p>The proposed G3 methodology does not allocate any refurbishment costs to generation.</p> <p>G3 are working within the current price control arrangements for generation.</p>   |
| <p>A supplier responded that:</p> <p>In addition to the questions raised in the consultation document, they are concerned about the approach used for some of the “other costs”. For example, forward looking estimates of Administration, Customer Service &amp; Billing costs are used. These costs are converted into £/customer values for the main billing approaches/systems used by the DNO. In their view this does not provide sufficient detail on the basis for allocation of these costs, however, if the allocation is carried out on a constant basis per customer, this would clearly be wrong. They would like to see detailed workings for how this allocation is carried out together with supporting evidence for the proportion of these costs allocated to each customer group. On the basis that this evidence has not been supplied, they do not support the approach contained in the consultation document. The same is true of pass through costs, again they consider that allocation of such costs on a constant £/customer or £/kVA basis is inappropriate.</p> | <p>With regards to how various costs are allocated to customer groups, the detail is provided in the G3 model.</p> <p>They accept that some cost allocations will be more arbitrary (administration, customer service &amp; billing) but these are genuine customer costs and the allocations are based on the best judgement of the G3 companies. Furthermore, these costs represent a relatively small portion of the overall pre-scaled total cost allocation.</p> |

**Is one year of actual cost data sufficient to produce forecasts of operation and maintenance and refurbishment costs?**

| <b>Consultation response</b>  | <b>G3 comment</b>   |
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| <p>A supplier responded that:</p> <p>The question regarding one years' data commands the same response as above. They suggest that in order to determine data stability and to better quantify potential impacts of inherent yearly trends that further sensitivity tests are conducted - work on an average years' data etc. may provide a better insight into data stability.</p> | <p>Respondents favour using more than a single years' data for forecasts of operation and maintenance and refurbishment costs. G3 will look again at this area.</p> |
| <p>A generator responded that:</p> <p>One year's worth of data is not relevant and could be heavily distorted i.e. by extremes of weather related problems in one year. Five years would be a more suitable number for averaging purposes.</p>  | <p>See comment above</p>  |
| <p>A distributor responded that:</p> <p>Using a single year's data as the basis for forecasting is unreliable and will likely deliver a greater volatility in charges than using several years' data.</p>   | <p>See comment above</p>  |
| <p>A supplier responded that:</p> <p>It is of the view that a single year's data is insufficient to produce robust estimates of O&amp;M and refurbishment costs. It is always possible that the year selected is atypical, either plus or minus, and on this basis, they would suggest a longer period be used to generate the forecasts.</p>                                       | <p>See comment above</p>  |

**Is the proposed revenue reconciliation approach of applying a different 'adder' to each voltage level in proportion to MEA value appropriate?**

| <b>Consultation response</b>  | <b>G3 comment</b>  |
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| <p>A supplier responded that:</p> <p>It was not clear from the document how the specific fixed adders have been generated and how the effects have been validated to ensure that they do not result in cross subsidies between customer groups. They do not agree that the revenue reconciliation approach should be applied in proportion to the MEA or solely on a per kVA basis. They believe that this is arbitrary and incorrect. In their view, the "other costs" referred to do not relate</p> | <p>The substantial difference between allowed revenue and present costs is largely to recover the ongoing cost of previous investments. The principle has been that investments at a particular voltage level should be paid for by users which draw kVA from or through that voltage level. G3 recognise that MEA values are not a unique way of allocating</p> |

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| <p>directly to MEA or capacity, and they believe that solely using capacity to allocate these costs will result in an over allocation to low voltage users and an under allocation to high voltage users. To produce an equitable result, they believe that the other costs should be allocated using a combination of volume and capacity. They believe that there are concerns in using a “fixed adder” revenue reconciliation approach, particularly when the discrepancy between allowed revenues and modelled costs is large. In these cases, they believe that a fixed multiplier approach is likely to produce a more equitable and less distorting effect.</p> | <p>the unallocated allowed revenue. G3 are looking more generally into the approach to revenue reconciliation.</p>   |
| <p><b>Should negative charges be permitted?</b></p>  |  |
| <p><b>Consultation response</b></p>  | <p><b>G3 comment</b></p>   |
| <p>Energywatch responded that:</p> <p>The capping of negative generation charges to zero would actually dilute a pure cost reflective approach.</p>  | <p>G3 currently have two constraints in relation to allowing negative charges:</p> <p>Firstly, the current generation price control does not allow the benefits of generation to be passed to demand customers and so negative charges applied to some generators would result in other generators being charged more.</p> <p>Secondly, there are currently billing constraints that will make negative charging difficult to implement.</p> <p>G3 would comment that although these constraints may prevent negative charges being implemented with this proposed methodology change, both may be overcome in the future, allowing G3 to make a further modification to their methodologies.</p> <p>As mentioned in chapter 2, G3 is currently looking into the possibility of publishing the effect of removing the cap.</p> |
| <p>A distributor responded that:</p> <p>In principle it is right to apply negative charges.</p>  | <p>See comment above</p>   |

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| <p>A supplier responded that:</p> <p>It is important that the methodology reflects the value of embedded generation to a local DNO as embedded generation can defer the need to reinforce the network to support the requirement for increasing demand. The inclusion of negative charging in the methodology will reflect that value and therefore they believe that negative charging should be allowed to reflect that value. Negative Charging may also encourage siting of generation in areas that negates the requirement for reinforcement for future growth demand which will provide a benefit for all DUoS payers. Furthermore the concept of negative charging exists on Transmission charging so they see no reason why it should not exist at a lower level.</p> | <p>See comment above</p>   |
| <p><b>Would it be appropriate to cap site specific EHV charges at the level of the equivalent generic HV charges to avoid perverse incentives at the boundary and, if so, should this be done before or after allocation of sole use asset costs to EHV charges?</b></p>   |  |
| <p><b>Consultation response</b></p>  | <p><b>G3 comment</b></p>   |
| <p>A supplier responded that:</p> <p>They see no reason to cap site specific EHV charges at the level of generic HV ones. Whilst this approach might relieve the occasional perverse incentive at the boundary, they believe that the risk of cross subsidy developing as a result of the application of the cap would outweigh any minimal benefit gained.</p>  | <p>G3 are looking into this issue and evaluating if it is likely to be material.</p> |

## 6. Other charging issues

| General   |  |
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| Consultation response   | G3 comment   |
| <p>A generator responded that:</p> <p>They would not feel that they as a group were treated fairly if they had to pay for others' poor power factor as part of an annual charge when they can actively improve things in the locality.</p>  | <p>We agree. We believe that reactive charging is an important part of any charging methodology.</p>   |
| <p>A trade association responded that:</p> <p>They note the comments on charging demand for excessive reactive power. They support this and point out that it follows that optimum use should be made of the reactive power capability of some types of generator and this should be exploited and paid for, in the same way as excessive consumption is charged for.</p>   | <p>See comment above.</p>  |
| <p>A distributor responded that:</p> <p>The proposed reactive power methodology does not reflect the additional costs caused on the network by energy consumption with a poor power factor.</p>   | <p>We are reviewing comments made in the consultation and at the workshop and are looking at possible alternative approaches to developing reactive charges.</p>   |
| <p>An energy consultant responded that:</p> <p>It would be better to fund replacement assets by ongoing charges rather than capital contribution. The need for replacement may not arise at the end of life because the assets may no longer exist. Recovering the replacement asset over the asset's nominal life would lead to excessive charges.</p>   | <p>We believe that replacement asset cost should reflect what actually happens and not based on a nominal replacement. We currently believe that there should be flexibility in the funding of replacement assets through either capital contribution or ongoing charging.</p>   |
| <p>A distributor responded that:</p> <p>Sole use assets should not form part of the network for the marginal costs calculation, as the asset will likely have been paid for by the connector and are unlikely to requiring reinforcement over the life of the connection. If reinforcement is required then this can be dealt with under the connection charging methodology. Therefore the nominal life of sole use assets</p> | <p>We agree that sole use assets should not form part of the marginal cost calculation, this is the treatment in our proposed FCP model.</p> <p>It is noted that a 40 years cost recovery period is preferred as this represents the physical life of many distribution assets. The potential for asset stranding also</p> |

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| should be its expected asset life i.e. 40 years.   | needs to be considered in determining the actual cost recovery period. |
| <p>A supplier responded that:</p> <p>In common with our previous responses, they believe that the nominal life of the assets should mirror the expected asset life rather than a nominal 10 years, which has the effect (at best) of bringing forward costs to customers.</p>  | See comments above.  |
| <p>A trade association responded that:</p> <p>The capital contribution on sole use assets should be based on their expected life rather than 10 years. The latter period is utilised as a window for reasonable certainty of future reinforcement. Sole use assets are already there so there is no question of uncertainty and they should be charged over their useful life.</p>   | See comments above.  |
| <b>Is the proposed approach to the sole use assets O&amp;M charge set out in 6.1, or the alternative methodology set out in 6.2, more appropriate?</b>   |  |
| <b>Consultation response</b>   | <b>G3 comment</b>  |
| <p>A trade association responded that:</p> <p>They prefer the more cost-reflective method of charging for O&amp;M of sole use assets given in paragraph 6.2, notwithstanding its greater volatility.</p>   | G3 note his response.  |
| <b>What should be the nominal life of sole use assets – should this align with the 10 years used for reinforcement, or mirror the expected asset life of, say, 40 years?</b>   |  |
| <b>Consultation response</b>   | <b>G3 comment</b>  |
| <p>A supplier responded that:</p> <p>In determining O&amp;M charges it is needed to clearly define and understand the differences between reinforcement and replacement and the ‘conflicts’ that may exist. For example, referring to the question raised in the last bullet in Chapter 6 – nominal life of sole use assets aligning with 10 year horizon or mirror asset lifespan of 40 years. What happens where an asset is replaced before the end of its 40 year lifespan as part of a reinforcement programme? It may be of concern that a significant amount of capital expenditure will be difficult to define as either replacement or reinforcement.</p> | G3 are considering this further.                                       |

## **7. Further considerations**

- 7.1. Following the G3 workshop, we are reviewing our reactive charging methodology.
- 7.2. More information will be provided about the HV/LV methodology to demonstrate how it better meets the relevant objectives.
- 7.3. We are reviewing the revenue reconciliation scaling method as well as the assumptions on cost allocations for the HV and LV network because of the disturbance observed on HV and LV tariffs.
- 7.4. Whilst we are not proposing any tariff structural changes, we are further considering the make up of the tariff components.

## **8. Next steps / timetable**

- 8.1 The G3 companies plan to submit individual proposals for modification of their methodologies to the Authority in September.
- 8.2 Depending on the Authority's decisions on these modifications, indicative tariffs will be announced in late December 2007 and prices will be confirmed in mid February 2008 for implementation with effect from 1 April 2008.