Consultation and impact assessment on SPEN's proposed modification to the DUoS charging methodology: Implementation of the FCP (G3) approach. Consultation of 17 June 2008, ref: 86/08.

Introduction and Summary

SP Energy Networks ('SPEN'), on behalf of SP Distribution and SP Manweb, welcomes the opportunity to comment on the issues raised in this consultation.

We believe that the SPEN FCP methodology better achieves the relevant objectives than the current approach in a number of respects, which were set out in detail in the modification report. We therefore believe that it merits a 'non-veto' decision by the Authority for implementation from April 2009, as proposed.

As regards the development of a common methodology across DNOs, such as is proposed in the letter issued by Ofgem on 22 July 2008, the "G3" approach on which the SPEN methodology is based is also, in our view, the strongest candidate if these proposals are implemented. The G3 method has the best balance of benefits and costs, it is ready to be implemented by 6 DNOs (which represents almost half of the DNO customers in Great Britain). It also has a good potential to be developed further to improve any perceived or identified weakness as well as to reflect industry developments.

The comments set out in this response are based, as far as possible, on the questions listed in Schedule 7 of the consultation but also including (as Schedule 7 seems to be incomplete) other issues raised elsewhere in the paper, mainly Annex 2. Apparent inaccuracies or misinterpretation of SP's proposals are mentioned where relevant.

Consultation questions

i) The use of Network group aggregation and different increments

1. ***The extent to which SP's approach to EHV demand charging is an acceptable trade off between cost reflectivity and stability.***

We believe there are two points for clarification with regards to this question.

Firstly, the proposed methodology for performing the Contingency Analysis is *not* fixed on 1% increments. It instead specifies "small steps", which can be adjusted if necessary. As explained in the modification report, the contingency analysis is used to identify in which year reinforcement would be required and therefore it is essential that increments are related to the level of demand. Figure A4 in Schedule 2 illustrates that the capacity of different network groups and plant covers a very wide range: the maximum demand of the network groups in SP Distribution range from about 7 to 110 MVA. If a fixed increment (in MVA) was used then a lower level of accuracy would be introduced in network groups where the capacity is small. In the SPD case, a fixed increment of 1MVA would represent some 14% of total demand in some groups. We do at present believe that 1% is an appropriate size for the increments, and although a smaller percentage increment could be used, this is regarded as unnecessary.

The second point of clarification is that the 15% upper increment for the contingency analysis (Ofgem's consultation say 115%, which is a typo) is *not* part of the methodology as such and is subject to review to match forecast growth rates at the time of setting charges. The wording included in the methodology statement clarifies that the small increments will be taken "up to a level that is able to encapsulate the expected growth in the network over the next ten years above their current maxima".

2. ***The extent to which the use of network group aggregation and separate increments are equitable and capable of producing economic signals which can lead to more efficient use of the system.***

We believe that a cost-reflective power flow analysis requires that each contingency condition is analysed. Figure A.8, Schedule 5 does not specify the methodology used to determine the nodal prices but, based on previous information and proposals from other DNOs, we believe that the analysis is only carried out under normal operating conditions and it therefore not a like-for-like comparison with FCP's single price for the Network Group. We believe that the validity of the variation of the nodal prices from the average prices for the Network Group has not been demonstrated and is likely to lead to false price variations between nodes. Performing a cost-reflective contingency analysis, at the level of detail proposed for FCP, at the nodal level would introduce considerable additional work, complexity, and computational analysis and we question whether it would be possible to validate such an analysis on anything other than simple test cases. The full analysis of each contingency would almost certainly lead to considerable additional volatility and an order of magnitude increase in complexity.

It is worth pointing out Frontier's conclusions in this area[1] that attempting to have nodal pricing would increase complexity and unpredictability with no proven benefit. We agree with this view.

3. ***The appropriateness of the charge pricing function.***

There are several points to make in this area:

Firstly, we would like to point out that the pricing function is a conscious departure from a "pure incremental cost formula". In simple terms, a "pure incremental formula" would not spread the reinforcement costs using the entire demand of the network group, but it instead would spread those costs to the increment used to determine the reinforcement costs. This, in our view, exposes the "pure incremental" method to the risk of overstating the charges[2] and therefore leads to a potential exposure under the Competition Act. If the rates are calculated based on an increment and then charged to the total demand it is not difficult to see how this could lead to over-recovery (and loss of cost reflectivity). The FCP charging functions (both for demand and generation) ensure that the total recovered via the charging function is equal to the change of NPV brought by the increment in demand (or generation). For the avoidance of doubt, the FCP function is an incremental one (as illustrated in Appendix 3 of our modification report).

We see with some concern the "de facto" parallel that seems to have been drawn between a "pure incremental" formula and a so-called "pure economic" approach (the meaning of the latter is not clear to us). To date, no proven economic justification has been attained for any of

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[1] Report available at http://www.scottishpower.com/StructureOfChargesProjectG3.htm

[2] For an analysis of this effect see the Reckon report commissioned by the G3, available at the same location as above.

the forward looking pricing methods being considered by the industry. It is not known what level of pricing signal, if any, would cause customers to locate in places that would lead to a more efficient use of the network, and the identification of “weak” or “strong” signals seems to be based solely on one method compared to the other (not on any measure of price elasticity). While we recognise the theoretical benefits of encouraging customers to connect to less utilised areas of the network we do question the effects of such price signals in the decision where to site and are concerned by the apparent little consideration given to the effect of locational signals to already connected customers. We therefore believe that a balance between a perceived “strength” of the pricing signal and a cost-reflective recovery needs to be sought.

Another point to mention in relation to the consultation document is the fact that the references to the two consultants reports commissioned by the G3 seem to have been taken out of context or misinterpreted to an extent. The Reckon report[3] is quoted as suggesting that the weaker cost signals would lead to “insufficient pressure on customers to locate where load cost would be minimised”. This, however, is presented by Reckon as part of a comparison between the G3 and the so-called LRIC method (as implemented by WPD). The report also states that the risk of a weaker signal is considered lower than the risk of overstating the pricing signals deriving from the WPD implementation of the LRIC method. The Reckon report states that “(the risk of charges being overstated) could lead to customers choosing less suitable locations or closing loads in cases where the saving in electricity network capital expenditure requirements does not justify the disadvantage”. We believe that in order to understand the comment from Reckon quoted by Ofgem in the consultation letter it should have been presented in this full context.

The consultation also cites the Frontier report as commenting that the “use of the charging function to recover the change in the NPV has no clear economic ground”. In the report, this point is explained by Frontier as part of their “potential concerns” (listed after all the identified “strengths” of the methodology) and it refers to the mathematical derivation of the pricing formula. It is perhaps worth clarifying that the Frontier report makes comments on an earlier draft version of the modification proposal which did not, in their view, explain the economic basis for the pricing formula. We think it is worth quoting the following paragraphs from the Frontier report:

> “It is important to note that these concerns relate to the process by which the EHV charging formula is reached and *not* the final form of the charging formula itself. The assumption made by G3 is used simply to “shape” the price function over the period of cost recovery. Rather than attempting to justify this shape from a mathematical perspective, it might be sensible simply to note that the assumption seems broadly sensible – reinforcements required earlier mean charges are higher. Indeed, as we have discussed previously, the charging formula has a number of desirable properties: it is ‘well-behaved’ in the sense discussed in the previous chapter and remedies the perceived weaknesses of the incremental cost pricing approach (as discussed in section 4.1.2).
>
> In our view, therefore, there is an argument that it would be better for the G3 to justify their EHV demand charging formula in terms of its desirable properties rather than presenting it as the unique analytical solution to a problem with no clear economic rationale.”

[3] Available at http://www.scottishpower.com/StructureOfChargesProjectG3.htm

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The advice given to us by Frontier, detailed in the previous paragraph, was taken into account when finalising the draft submitted to Ofgem. The report was modified to reflect the fact that the FCP formula is an empirical one, which was chosen due to its desirable properties[4].

ii) The use of a test size generator and standard probability in EHV/HV generation charges

4. ***We ask for views on the extent to which the use of the test size generator represents an appropriate trade off between a forward looking, cost reflective methodology and a methodology which produces predictable, stable prices***.

We are not sure, from the drafting of the question, to which one of the two options (the "forward looking, cost reflective methodology" or the one "which produces predictable, stable prices") the FCP is being linked to. All we can do is to re-state (as we have done in the modification report) that we believe this approach is an appropriate one to model generation given the characteristics of the market as it is at the moment. We believe the approach *is* forward looking *and* cost reflective as well as not seeing any risks of charges that are unduly unpredictable or unstable.

5. **We ask respondents to consider the fact that EHV demand growth is also likely to be lumpy. Respondents may also wish to consider the anticipated growth of distributed generation which is likely to flatten any 'lumpy' connection of generation.**

We believe that, regrettably, this question has been drafted in a way which might be considered to be "leading" to a particular answer. While it is true that EHV customers, considered in isolation, could be characterised as "lumpy", we would like to point out that only around 15 % of the demand flowing through the EHV network is due to EHV demand. The rest is electricity which continues to flow to the lower voltage levels (HV and LV) which do present a much "smoother" growth trend. This is the basis for our decision to model demand and generation growth in a different way, as their overall growth behaviour is different.

iii) Varying the size of the test size generator

6. ***We welcome views on the extent to which it is appropriate for generator charges to go up when smaller generation connects to the network, and down when larger scale generation connects to the network.***
7. ***We also welcome views on whether the substantial differences between test size generators at different voltage levels may influence connection decisions i.e. a generator may connect at 33kV rather than 132kV.***

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4 These properties are:

- Linear variation with reinforcement cost.
- Rate increases as reinforcement approaches.
- For a given demand, the rate should increase with increasing growth rate to give stronger signals.
- Increasing the discount rate should give lower rates at more distant times prior to reinforcement.
- The decrease of rate with increasing discount rate should be stronger than exp(-*it*).
- As the growth rate tends to zero the rate should tend to zero for all demands less than the capacity at which reinforcement is required.

One of the main causes for the increase in generation charge rates as the 'test size' decreases (Table A3, schedule 2) seen in Ofgem's analysis reflects the fact that the cost of the reinforcement is kept constant, which is an important weakness in the analysis itself. The size and hence cost of reinforcement is geared to the particular voltage level and typical load flows: if typical generation connections become smaller, reinforcement solutions would become smaller (and cheaper) too. In order to perform a meaningful sensitivity analysis, the variations in the test size should go hand in hand with new contingency analysis.

iv) Use of historic RRP data in HV/LV charging – Revenue reconciliation

(The following two bullet points are unmarked questions in Annex 2 which are not in Schedule 7):

- ***We welcome views on the extent to which SP's proposed scaling approach is appropriate both in terms of the 'COG' model and voltage level scaling.***
- ***We also welcome views on whether the different scaling approaches to demand and generation are appropriate.***

The consultation mentions the concern about possible "distortions" of charging signals caused by the use of a revenue reconciliation approach based on MEAV values at the different voltage levels. As explained in detail in the modification report, we believe this approach is appropriate and proportionate to what the scaling is reflecting: historical costs. We believe that using the same "fixed adder" to all voltage levels would cause customers at the EHV and HV level to, effectively, pay for costs which they have not triggered. This goes against the principle of cost reflectivity and could be argued to distort the price signals. Additionally, it is worth mentioning that our approach helps allocating scaling to the lower voltage levels, which have been recognised (at least empirically) to have a lower price elasticity than the higher voltage levels. This is surely a desirable effect.

8. ***We welcome views on the extent to which the use of historical RRP represents an appropriate trade off between cost reflectivity and simplicity, and whether this approach is transparent given that RRP data is not published.***
9. ***We also invite views on whether a backward looking average technique appropriate given the presence of developed forward looking models, particularly for the calculation of HV and LV reinforcement costs.***

Once again we regret the "leading" tone of the two questions above. In relation to question 8, we are unsure on which of the two options ("cost reflectivity" and "simplicity") is the one being associated with the G3 method. We think our method is cost reflective and simple. Also, we do believe the approach is transparent in that it is derived from auditable data (even though it is not currently published). Moreover, we have proposed making the models available to users (which will include the inputs used and improve transparency).

In relation to question 9, we regret the use of the term "backward looking" (which seems to imply the diametrically opposite to "forward looking") to describe the proposed approach. The method uses historical data to derive a forward view of costs, which in our view constitutes a forward-looking method. We also question the "presence of *developed* forward looking models", as it is our understanding that at the moment the DRM (for those companies that apply it) is not a uniform or developed model at all and we question whether it is really cost reflective.

Finally, it is important to clarify that SP Distribution and SP Manweb **do not** currently use the DRM model, but instead a model which is based in an average view of network costs (by voltage level), over which method the G3 approach is clearly, with no room for doubt, an improvement which allows to better meet the relevant objectives.

v) Time banding

Note: We have no further comments at this point in relation to Questions 10 to 12, other than the full justification given in the modification report.

13. ***We welcome views as to whether it is appropriate to only consider demand reinforcements which will occur within a ten year period. Does this represent a practical trade off between a forward looking model and a simplistic approach?***

14. ***We welcome views on whether it is appropriate to only assess the benefit generation can have in deferring demand reinforcements due within ten years. Does this adequately reflect the benefits which generation can provide to the distribution network?***

15. ***We welcome views on the potential for the use of a ten year period to lead to tariff jumps as lumpy demand connection brings forward reinforcement by a number of years.***

The justification of our choice of considering the reinforcements for demand and generation due within 10 years has been amply justified in a number of bilateral discussions with Ofgem, as well as at industry fora and workshops. The only additional point of clarification we consider necessary at this point in relation to the consultation is that it is not clear what option the FCP method is linked to: a “forward-looking” or a “simplistic” one. “Simplicity” is not the reason why the 10-year analysis period was chosen but instead cost reflectivity, and this approach is forward looking in our view.

vi) *Recognition of intermittent generation*

16. **We welcome views on the extent to which SP are correct in using F factors to calculate the benefit LV generation can provide to the network.**

We believe that, in this point, the consultation analysis and description of the method falls short of a full understanding of the approach, probably mostly due to a less than extensive explanation, from our side, in the methodology report itself about the proposed approach.

The proposed approach recognises benefits from generation *over and above* those prescribed by P2/6 rules. The P2/6 recommendations do not go as far as recognising contribution in all of the voltage levels above the point of connection, whereas our pricing decision was to recognise these benefits up to the highest EHV point. The use of the P2/6 “F” factor, in this case, is a proxy for the coincidence factors which have been discussed in different industry forums recently, as we believe the two concepts (P2/6 security of supply and coincidence factors deferring demand-triggered reinforcement needs in the higher voltage levels) are related to the probability of the generation being generating output, represented by an “F” (probability) factor.

We think it is worth mentioning that in this point our approach evolved through time and after considering stakeholders' views (including Ofgem's). For information, please find attached in Annex 1 with our initial "P2/6 only" approach and the final "pricing" approach, which is the one adopted for the methodology proposal. This illustrates how we have extended the benefits all the way up the voltage levels and also have ignored considerations about size of the generator, which are recommended by the P2/6 technical recommendations.

vii) Reactive power charging

17. **We welcome views on the extent to which SP's proposal encourages EHV customers to make the most of their power factor as well as on their changes to HV/LV reactive power charging.**

We would like to point out that our proposed charges to EHV customers will be in kVA, which indirectly recognises good (or poor) power factors.

Annex 1 - a. “P2/6 only” pricing approach

Marginal Costs Allocation

Site Specific

FCP Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	33kV BSP Busbars	33kV Network	HV Primary Busbars	Generation >100kVA: 132kV	33kV	HV Primary Busbars
132kV Switchgear	Demand (D1)	D1	D1	D1	D1			
	Generation (G1)					G1		
132kV Circuits	Demand (D2)	D2	D2	D2	D2		-f x D2	
	Generation (G2)							
132/33kV Transformers	Demand (D3)		D3	D3	D3		-f x D3	
	Generation)G3)						G3	
33kV Switchgear	Demand (D4)		D4	D4	D4			
	Generation (G4)						G4	
33kV Circuits	Demand (D5)			D5	D5			
	Generation (G5)							
33/11kV Transformers	Demand (D6)				D6			-f x D6
	Generation (G6)							G6
11kV Switchgear	Demand (D7)				D7			
	Generation (G7)							G7

Tariff Model

Tariff Model Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	33kV BSP Busbars	33kV Network	HV Network	LV Network	Generation > 100kVA: 132kV	33kV	HV	LV
132kV Network	Demand	D1 + D2	D1 + D2	D1 + D2	D1 + D2	D1 + D2		-f x D2		
	Generation						G1			
132/33kV Substation	Demand		D3 + D4	D3 + D4	D3 + D4	D3 + D4		-f x D3		
	Generation							G3 + G4		
33kV Network	Demand			D5	D5	D5				
	Generation									
33/11kV Substation	Demand				D6 + D7	D6 + D7			-f x D6	
	Generation								G6 + G7	
11kV Circuits	Demand (D8)				D8	D8			-f x D8	
	Generation (G8)								G8	
11kV/LV Transformer	Demand (D9)					D9				-f x D9
	Generation (G9)									G9
LV Circuits	Demand (D10)					D10				-f x D10
	Generation (G10)									G10

Key:
= values from FCP Marginal Cost spreadsheet
= values derived from RRP data
= marginal cost N/A

Notes:

Nomenclature
Costs are denoted D if related to demand reinforcement and G if related to generation
Benefits are shown as negative
Benefits are proportional to generation contribution 'f' and are determined using ENA Engineering Techinical Report 130 (Application Guide for Assessing the Capacity of Network Containing Distributed Generation (ETR 130) Section 6 considering generator
('f' for LV generation is typically zero due to the requirement for loss of mains protection and isolation)

Demand
Costs: Demand costs are cumulative from the point of connection up to the highest network voltage
These costs include switchgear, circuits and transformers

Benefits: There are no demand benefits

Generation
Costs: Generation costs are associated with the substation busbar at the point of connection only
These costs include switchgear and transformers
(Circuit costs are not included since generators are assumed to connect directly to the LV side of the transforming busbar)

Benefits: Generation benefits are cumulative from the point of connection up to the highest level at which the generator can contribute to network security
Contribution to network security is defined in ETR 130 and its summarised for a typical DNO network below (table 1)
Benefits are equal to the demand costs, scaled by the generation contribution factor f' and include upstream circuits and transformers
(demand costs for switchgear are not included in generation benefit as generators do not defer demand related reinforcement of switchgear)

Table 1: Generation benefit is due if generation size is of significant size to contribute to security of supply
I.e. if DNC > 5% of Group Demand (ETR 130 5.5.1)

Demand Group/ Connection Point	Demand	Min DNC	Can generator significantly contribute to defer demand reinforcement?: 132 kV	33 kV	11 kV	LV
	Typical average values		75 MVA	25 MVA	3.5 MVA	0.5 MVA
400/132	450 MVA					
132kV GSP Busbars		22.5 MVA	YES	YES	NO	NO
132/33	90 MVA					
33kV BSP Busbars		4.5 MVA	x	YES	NO	NO
33/11	15 MVA					
HV Primary Busbars		0.75 MVA	x	x	YES	NO
HV/LV Transformer	1 MVA					
LV		0.05 MVA	x	x	x	YES

Annex 1 - b. Decided “pricing” approach

FCP Costs Allocation

Site Specific

FCP Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	Demand point of Connection: 33kV Network	Generation: 132kV	Generation: 33kV
132kV Switchgear	Demand (D1)	D1	D1	-f x D1	-f x D1
	Generation (G1)			G1	
132kV Circuits	Demand (D2)	D2	D2	-f x D2	-f x D2
	Generation (G2)				
132/33kV Transformers	Demand (D3)		D3		-f x D3
	Generation (G3)				G3
33kV Switchgear	Demand (D4)		D4		-f x D4
	Generation (G4)				G4
33kV Circuits	Demand (D5)		D5		-f x D5
	Generation (G5)				
33/11kV Transformers	Demand (D6)				
	Generation (G6)				
11kV Switchgear	Demand (D7)				
	Generation (G7)				

Tariff Model

Tariff Model Categories	Reinforcement Costs	Demand point of Connection: 132kV Network	Demand point of Connection: 33kV BSP Busbars	Demand point of Connection: 33kV Network	Demand point of Connection: HV Network	Demand point of Connection: LV Network	Generation: 132kV	Generation: 33kV	Generation: HV	Generation: LV
132kV Network	Demand	D1 + D2	D1 + D2	D1 + D2	D1 + D2	D1 + D2	-f x (D1 + D2)	-f x (D1 + D2)	-f x (D1 + D2)	-f x (D1 + D2)
	Generation						G1			
132/33kV Substation	Demand		D3 + D4	D3 + D4	D3 + D4	D3 + D4		-f x (D3 + D4)	-f x (D3 + D4)	-f x (D3 + D4)
	Generation							G3 + G4		
33kV Network	Demand			D5	D5	D5		-f x D5	-f x D5	-f x D5
	Generation									
33/11kV Substation	Demand				D6 + D7	D6 + D7			-f x (D6 + D7)	-f x (D6 + D7)
	Generation								G6 + G7	
11kV Circuits	Demand (D8)				D8	D8			-f x D8	-f x D8
	Generation (G8)									
11kV/LV Transformers	Demand (D9)					D9				-f x D9
	Generation (G9)									G9 *
LV Circuits	Demand (D10)					D10				-f x D10
	Generation (G10)									G10 *

* G9 and G10 = zero

Key:

= values from FCP Model
= values derived from RRP data
= marginal cost N/A

Notes:

Nomenclature **Costs are denoted D if related to demand reinforcement and G if related to generation**
Benefits are shown as negative
Benefits are proportional to generation contribution 'f and are determined using ENA Engineering Technical Report 130 (Application Guide for Assessing the Capacity of Network Containing Distributed Generation (ETR 130) Section 6 considering
('f for LV generation is typically zero due to the requirement for loss of mains protection and isolation)

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Costs: Generation costs are associated with the substation busbar at the point of connection only
These costs include switchgear and transformers
(Circuit costs are not included since generators are assumed to connect directly to the lower voltage side of the transforming busbar)

Benefits: Generation benefits are cumulative from the point of connection up to the highest network voltage level
Benefits are equal to the demand costs, scaled by the generation contribution factor f and include upstream circuits and transformers