

Responses to Consultation on **potential changes to the Use Of System** **Methodology**

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**BRITISH ENERGY RESPONSE TO WESTERN POWER DISTRIBUTION
CONSULTATION ON POTENTIAL CHANGES TO THE USE OF SYSTEM
METHODOLOGIES**

Thank you for the opportunity to comment on the above consultation document which raises a number of important issues.

British Energy is a large supplier selling exclusively to Industrial & Commercial customers. British Energy Direct accounts for around 30 TWh of the UK supply. British Energy is also the UK's largest generator of electricity. In addition to our transmission connected nuclear and coal fired stations we own and operate four small, embedded gas generator sites.

As a supplier we value stable, transparent and predictable DUoS charges. Overall the charging methodology should be as simple as possible as should the tariff structure. We are very supportive of the process to establish a common charging methodology applicable to all DNO's and appreciate the DNO's work in moving towards this goal.

Through participation at the ISG we are aware of Ofgem's desire to see revisions to the present DNO charging model driven in part by the growth in embedded generation and by a desire to see the introduction of a forward looking long run incremental cost model since they consider that charges should influence future behaviour and hence investment decisions. National Grid has used such a model (ICRP) to set transmission tariffs for some years. This model has undergone several significant developments with the introduction of a dc load flow model and forward as opposed to historical incremental cost parameter in E&W in 2004 followed by its extension to GB under BETTA. Both these changes caused regulatory uncertainty which still persists given the conditions for review placed on National Grid at the time of approval. We would not wish to see this level of regulatory driven change affecting distribution use of system charging so it will be important to take time to make sure changes are properly thought through before being implemented.

Turning to the specific questions asked:

Does the AC ICRP method outlined above better achieve the licence objectives than the existing methodology?

The AC ICRP approach allows a more detailed representation of the network and the modelling of reactive power flows and thus may result in more cost reflective charging. Set against this however is the additional complexity and data requirements which would almost certainly limit the application of the charging approach to the EHV portion of the network. This could be viewed as discriminatory and therefore on balance may not better facilitate the licence objectives overall.

Are there further advantages or issues with the approach described?

The ICRP approach while established on the transmission system has only had very limited application to a simplified representation of a distribution network more detailed work will be needed before such an approach based on either dc or ac load flow models can be properly assessed.

With the AC ICRP method, there is a need to allocate an ‘unused’ or non marginal charge. Is a universal £/kW or p/kWh best or should some other method be used?

While a flat charge seems to be the most appropriate the G:D split needs to be considered.

In terms of investment in the network, around 30% is associated with expansion whilst the other 70% is associated with replacement of system assets. Whilst replacement decisions can be affected by reductions in system loads, historic analysis shows this to be rare. Hence should the locational message from the AC ICRP approach be:

restricted to 30% of the charge ?

allowed to reflect whatever results from the model ? or,

be scaled up to reflect 100% of the charge ?

Restricting the locational message to 30% of the charge would seem most appropriate.

As highlighted there are difficulties in applying the method to 11kV and LV systems. Is either of the approaches suggested appropriate or should some other method be used?

Given the complexity of applying ICRP to 11kV and LV systems some form of proxy would be necessary. Much care and effort will need to be taken if discriminatory charging is to be avoided.

Currently the AC ICRP method starts from demand at time of WPD system peak demand. Use of this for price setting purposes is likely to cause hunting of the peak demand as users of the network seek to avoid the peak period. Currently we are considering using an average of the top 20 peak half hourly demands to define the input to the model. This sends a strong message to users to avoid periods likely to contribute to reinforcement of the system. Views on how to define the demands used in the model are welcome.

There is clearly an interaction here with transmission charging and Triads and users behaviour to charging signals. A consistent signal is needed and hence this question cannot be answered in isolation to the Ofgem led review of enduring transmission charging for embedded generation.

Parts of our system have a significant night peak. Should, and if so how should this be accommodated within the AC ICRP approach? Similarly reinforcement can be triggered by high generation output during periods of low demand – views on how to accommodate this are also welcome.

Again this needs to be considered in association with the enduring transmission charging arrangements for embedded generators to ensure consistency of signals.

Our connection charging methodology requires a contribution towards system reinforcement as part of the connection charge. This is not based on a physical boundary and hence is difficult to incorporate into the AC ICRP approach. Views on whether and if so how this can be incorporated are welcome.

This is a key issue. In undertaking the assessment and presenting the benefits of the ICRP and LRIC approach to charging this locational signal was ignored. This element of the charge should be included and the Ofgem analysis repeated so that an accurate picture of the benefits obtained. It would seem inappropriate to levy both locational DUoS and connection charges as this would exaggerate the locational element of the charge.

LRIC model consultation questions

Does the LRIC approach outlined above better achieve the licence objectives than the existing methodology?

The approach would seem to be superior to that of ICRP given that it produces charging signals that relate to the likely amount of investment a connection would trigger and thus would appear to be representative of actual network conditions. That said caution must be exerted given that the approach has only been applied to a simple representation of a DNO network. The additional complexity and data requirements which would almost certainly limit the application of this charging approach to the EHV portion of the network is another important factor. This could be viewed as discriminatory and therefore on balance not better facilitate the licence objectives overall.

With the LRIC method, there is a need to allocate an ‘unused’ or non marginal charge. Is a universal £/kW or p/kWh best or should some other method be used?

As with ICRP a flat charge seems to be the most appropriate but the G:D split needs to be considered.

In terms of investment in the network, around 30% is associated with expansion whilst the other 70% is associated with replacement of system assets. Whilst replacement decisions can be affected by reductions in system loads, historic analysis shows this to be rare. Hence should the locational message from the LRIC approach be:

restricted to 30% of the charge ?

**allowed to reflect whatever results from the model ? or,
be scaled up to reflect 100% of the charge ?**

Restricting the locational message to 30% of the charge would seem most appropriate.

The LRIC approach has three main parameters highlighted in that section. Are the approaches being used reasonable? In particular, how should parts of the network with zero or negative load growth be treated where change of the system assets for replacement purposes will occur before the assets are changed for reinforcement purposes

Further work is needed to determine the correct charging approach.

As highlighted there are difficulties in applying the method to 11kV and LV systems. Is either of the approaches suggested appropriate or should some other method be used?

Again this needs further assessment however as noted above it would seem discriminatory to apply forward looking long run incremental cost charging to EHV customers alone.

Currently the LRIC method starts from demand at time of WPD system peak demand. Use of this for price setting purposes is likely to cause hunting of the peak demand as users of the network seek to avoid the peak period. Currently we are considering using an average of the top 20 peak half hourly demands to define the input to the model. This sends a strong message to users to avoid periods likely to contribute to reinforcement of the system. Views on how to define the demands used in the model are welcome.

See answer under ICRP.

Parts of our system have a significant night peak. Should, and if so how should this be accommodated within the LRIC approach? Similarly reinforcement can be triggered by high generation output during periods of low demand – views on how to accommodate this are also welcome.

See answer under ICRP.

Our connection charging methodology requires a contribution towards system reinforcement as part of the connection charge. This is not based on a physical boundary and hence is difficult to incorporate into the LRIC approach. Views on whether and if so how to incorporate this are welcome.

See answer under ICRP.

Further overall consultation question

Whilst views are welcome on any aspect of this consultation, we would particularly welcome views on the consultation questions in the above sections and the following question:

If both the AC ICRP and LRIC approaches better meet the objectives, then which of the two better achieves them?

While both methodologies appear to better meet the objectives in respect of the EHV sections of the network it is not at all clear that this is true for the 11kV and LV networks and therefore that overall either better meet the objectives. On the basis of the work done thus far the LRIC approach seems superior but the benefits identified ignored the impact of existing locational signals provided by connection charges.



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WPD Pricing
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17th February 2006

Dear Simon,

Consultation on potential changes to Western Power Distribution Use of System Methodology

Thank you for the opportunity to comment on your consultation.

In your introduction you state that the purpose of the consultation is to:

- summarise the work that WPD has been doing on reviewing its Use of System Methodology
- seek views on the type of methodology that is most appropriate to meet our licence obligations
- highlight key parameters and assumptions in the alternative methods being considered and seek views on the appropriateness of these assumptions, and
- seek views on how the methods should be further developed where known issues have yet to be accommodated.

While your paper provides an overview of the work that WPD has been doing we feel it does not provide sufficient information for EDF Energy to arrive at a robust view of its appropriateness in further meeting the licence obligations.

Similarly, in highlighting the key parameters and assumptions you have indicated the complexity of the model and documented significant issues still needing to be addressed.

While we acknowledge the work that WPD are doing, we are unable, at this time, to provide specific views on how your models should be developed due to the inconclusive nature of your paper. We believe that further clarity needs to be provided as to the benefits of the ICRP and LRIC approaches and specifically how cost reflectivity is achieved and passed through in the tariffs finally seen by customers.

Please contact me on 01293 657920 should you wish to discuss this further.

Yours sincerely

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Friday 17th February, 2006

Simon Yeo
Pricing
Western Power Distribution

Via e-mail: wpdpricing@westernpower.co.uk

Dear Simon,

Reference: Consultation on potential changes to the Use of System Methodology

Thank you for the opportunity to comment on the above consultation.

Unfortunately, in the absence of transparent examples as to the effect of the different proposals, we have found it extremely difficult to carry out a thorough evaluation of the potential changes and their impacts. Our response is, therefore, at a very high level, and we may wish to make further comment once WPD has provided some clear illustrations as to the actual effects of the proposals.

The document explains that a further consultation will be issued in late spring/early summer and we would encourage WPD to include worked examples of impacts at this point.

We note the proposals made, and believe according to our understanding, that either methodology will result in the collection of the same amount of allowed revenue in total, but the apportionment between different groups will vary.

Centrica is supportive of the principles of cost reflectivity and greater transparency, and would urge that any change to the methodology be tested against these principles to ensure it improves performance against both these key objectives.

We do not have a particular preference between the two methodologies described in the consultation at this point in view of our comments above; however, we would like to make some general observations.

We agree that the existing approach does not adequately address embedded generation on EHV networks or micro-generation on 11kV networks that causes a GSP to export. However,

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it is not clear whether WPD considers this to be an existing issue, or that it may become an issue on their specific network. We would welcome further clarification on this point.

In general terms, we believe that it is important that the chosen methodology does not distort allocation of costs in respect of the observed Night Peak, by under-allocating costs to Night Peak Demand relative to the Day Peak Demand.

Once the base numbers have been achieved, we appreciate that scaling will be required. However, we would be concerned to ensure that this is carried out equitably, and that the absence of a detailed model for lower voltages does not result in over-allocation of costs to these users. In our view the document does not clarify sufficiently how this scaling process will be managed.

The consultation raises valid questions in respect of investment signals; but, in the absence of a clear understanding of the effect of the proposals on different consumer groups, we do not feel able to answer definitively. However, we do not believe that the document gives sufficient consideration to alternatives to investment and the possible trade-offs that could result. For example, in our view, system reinforcement may not be the most efficient outcome; constraining the generator off may be a more economic solution, once all costs have been taken into account. We would encourage WPD to further consider such options in the next consultation.

Centrica is also concerned about the lack of consideration given to the lower voltage levels in the document. It is our understanding that a significant proportion of the revenues associated with Distribution Charging accrue from these lower levels, and hence they merit equal attention with the EHV and HV Networks

In respect of the point above, Centrica believes that it must be better to use representative networks to assess the 11kV and LV systems, than to continue with the existing method. However, this is clearly only true if the representation of the networks is robust. From the document, it is not clear how the "robustness" of the network representation would be tested/proven. It is also not clear how the representation would be developed to reflect the changing nature of the networks as they evolve.

It would also be important to ensure user confidence in the new method; Centrica believes that this could best be achieved by full transparency of the model and supporting data.

Providing these concerns could be overcome, we are of the view that a representative network could prove a robust basis for assessing the 11kV and LV networks.

In conclusion, whilst we do not feel able, at this stage, to express a definitive opinion on the detailed questions raised in this consultation, we hope that if WPD provides additional information in the next consultation, we would be able to be more specific.

We trust that these comments have been helpful, but if you would like to discuss any of the points raised in more detail, I should be happy to help.

Yours sincerely,

Alison Russell
Regulatory Issues Manager

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SSE Energy Supply Limited (SSEESL)

**Response to WPD's consultation on
Potential Changes to Use of System Methodology**

From: Richard Westoby, Pricing and Forecasting Manager

Date: 17 February 2006

Summary

This is SSEESL's response to the consultation issued electronically by Western Power Distribution (WPD) on 10 January 2006.

We set out some detailed points and responses to specific questions raised in the following sections. However, our main overall points are set out below.

1. We are very concerned that WPD is proposing a significant change of methodology for EHV customers with no indication of the potential magnitude of changes affecting individual customer sites.
2. We do not find the description of the two alternative methodologies proposed very easy to follow. There is not enough information to assess the detail or sensitivities of the models. Our experience is that such forward-looking models produce output that shows volatility from year to year and which is very sensitive to the precise assumptions used.
3. Both the models appear complex, with the prospect of changes in the charges to particular users over time due to network changes and the changing capacity requirements of other users.
4. The consultation process appears rushed and inadequate, with no reference or clear linkage with the parallel work being undertaken by distribution network operators (DNOs), including WPD themselves, jointly.
5. We do not believe that the case has been adequately made to move away from the existing charging methodology.

General Comment on Process

We are aware that DNOs are jointly reviewing longer-term arrangements for use of system charging and have participated in the initial workshop, held in January. WPD are represented in the joint DNO group and it is not clear why you are also carrying out a parallel consultation on an accelerated timescale, on a different methodology.

In our view, this separate consultation being conducted solely by WPD has all the appearance of an idea that has not been fully developed being rushed through for implementation in April 2007, without adequate explanation, debate and price impact analysis of the proposed change. It does not compare well with the joint DNO consultative process, which has a clearly signalled timetable covering workshops and opportunities for stakeholders to feed in views as different strands of charging methodology are developed towards a revised approach over the course of a year. It also raises the issue of potential inconsistencies between an amended approach by WPD and the output of the joint DNO work.

Comment on section titled “Background”

We note the references in this section to Ofgem’s November 2003 and May 2005 documents on charging structure. We understand that the modified standard licence conditions governing DNO charging requirements give the responsibility for developing charging methodologies to the DNOs rather than to Ofgem. We therefore do not accept that Ofgem’s view that use of system charges “should be fully aligned with ... models based on forward looking long run incremental cost (LRIC)” is a valid basis for a fundamental review of charges, which will affect the charges payable by many individual parties. We also note that there was disagreement between the academics referred to in the second document on the “best” way to develop distribution network charges.

Comment on section titled “Issues with the DRM approach”

We do not believe that “not providing locational signals” is a valid criticism of the current approach to setting use of system charges. Locational signals, to the extent that they need to be provided to users, can be (and arguably are best) given at the time a customer seeks to connect to the distribution system through the connection charge. All existing customers will have paid a connection charge and thus been provided with a locational signal under the policy prevailing at the time the connection was established. Under the current arrangements for “shallowish” connection charges, new users will continue to receive a locational signal. It appears to us that the benefits of simplicity, transparency and predictability in existing charging arrangements outweigh any notional and unproven benefits of trying to provide a time-varying locational signal, via the use of complex models, in use of system charging arrangements as well.

Similarly, it is not clear to us that the need for a separate method for setting generator use of system charges is necessarily a drawback or a problem that needs to be solved by the use of significantly more complex charging models.

Comment on section titled “Advantages of AC ICRP approach”

One of the claimed advantages is that this approach “generates locational charges”. See comments above on locational charges. We do not believe that it is necessary to have locational signals in use of system charges, so do not see this as an advantage. Another claimed advantage is that this methodology “allocates costs on the basis of usage of the network” – we understand that this is what the current methodology does, so this does not appear to be a specific advantage of making the change. Yet another advantage claimed is that this approach is similar to the transmission charging methodology. As far as we are aware, transmission charging methodology has not been without problems, challenges from users and instability for some peripheral charging zones. On this basis, we do not agree that being similar to transmission charging methodology is an advantage of this methodology.

Comment on section titled “Issues with the AC ICRP approach”

There are a number of substantive points listed in this section which, taken together with our comments on issues with the current methodology, tend to confirm our view that the case has not been made for changing from the existing methodology.

Comment on section titled “Advantages of AC LRIC approach”

Our comments above on the claimed advantage of generating locational charges are also relevant here. The third advantage claimed for this approach is that it “assesses the change in future investment needs rather than an allocation of costs”. In our view, an “allocation of costs”, as in the current methodology, is a more cost reflective approach than trying to establish categoric future investment needs and notional changes to these.

Comment on section titled “Issues with the AC LRIC approach”

To an even greater extent than the issues associated with the AC ICRP approach, the list of issues in this section demonstrates, in our view, that the methodology is not yet fit-for-purpose. In the areas of modelled load growth and reinforcement costs, general rules are said to be necessary due to the difficulties of providing more specific, actual values. If this has to be the case in applying the proposed LRIC approach at EHV level, it demonstrates the impracticability of the methodology in even these limited circumstances. It also demonstrates, in our view, the tenuous link between the modelled and actual future costs.

It should be possible for a DNO or a supplier to simply and clearly explain to a customer why their use of system charges have changed from one year to the next. Compared to the straightforward allocation of costs in the existing model, the LRIC approach would appear to fall far short of this test.

Response to Consultation Questions

- *Are there further advantages or issues with our existing methodology?*
In our view, it has not been demonstrated that there are such fundamental problems with the existing methodology that it is necessary to use a completely different approach for setting EHV charges. As existing EHV charges are covered by a transitional arrangement rather than the main existing use of system methodology, we would prefer to see a well-signalled development of the existing methodology to cover EHV charges.
- *Does the AC ICRP method outlined above better achieve the licence objectives than the existing methodology?*
We do not believe that the methodology outlined would better achieve the relevant objectives. Greater uncertainty and instability in charges, compared to the current arrangements would not facilitate competition in the generation and supply markets and would, in our view, be detrimental to competition. It is also unclear that charges based on forward-looking views would actually be more cost reflective than charges based on an assessment of costs incurred, as in the present methodology.
- *Are there further advantages or issues with the approach described?*
Our major concerns with the proposed approach are the instability and volatility we believe it would bring to EHV use of system charges. We have seen these effects in other forward-looking marginal cost based charging models. Furthermore, we are aware that the output from such models is very sensitive to the underlying assumptions used. There is no attempt in the consultation at discussion or quantification of these effects, which we believe would be disadvantageous to our EHV customers.

We also note that WPD (in common with some other DNOs) recently proposed changes to their EHV methodology that resulted in significant price swings for individual customers. After consultation, Ofgem capped any individual changes to the level of RPI increases. We believe such swings will not be acceptable to Ofgem, customers and suppliers but the consultation is silent on any methodology to deal with this aspect of a change to methodology.

- *With the AC ICRP method, there is a need to allocate an ‘unused’ or non marginal charge. Is a universal £/kW or p/kWh best or should some other method be used?*
It is difficult to comment on this as there is no information on how it would affect charges but it appears to be another factor limiting the cost-reflectivity of this approach.
- *In terms of investment in the network, around 30% is associated with expansion whilst the other 70% is associated with replacement of system assets. Whilst replacement decisions can be affected by reductions in system loads, historic analysis shows this to be rare. Hence should the locational message from the AC ICRP approach be:*
 - *restricted to 30% of the charge ?*
 - *allowed to reflect whatever results from the model ? or,*
 - *be scaled up to reflect 100% of the charge ?*

As noted above, we are not convinced of the need to provide locational signals in use of system charges. The potential variability in the proposed approach highlighted in this consultation question highlights the difficulty in establishing an unequivocally “right answer” in a forward-looking approach. All these alternatives would have different potential outcomes for different EHV customers, leading to the possibility of continual challenge from those whose charges are adversely affected.

- *As highlighted there are difficulties in applying the method to 11kV and LV systems. Is either of the approaches suggested appropriate or should some other method be used?*

As noted above, we do not believe the case has been made to change from the existing methodology. We are aware that DNOs collectively are reviewing use of system charging methodology and, if change were demonstrated to be necessary and beneficial, we would expect any changes to be introduced in an orderly, well sign-posted manner. Especially for customers at lower voltage levels, due account must be taken of suppliers’ investment in existing billing systems.

There are additional considerations for charging methodologies for voltage levels below EHV in the “mass market” for supply. Firstly, radical changes to the level, structure and volatility of distribution charges would impose a fixed overhead on suppliers costs due to required changes in billing and quotation systems - this would put small suppliers at a disadvantage and could therefore be seen as anti-competitive. Secondly, the increase in suppliers’ costs in adopting changes to billing systems together with appropriate risk premium to cover increased volatility in distribution charges would lead to an overall increase to customers’ bills in these markets. Thirdly, changes in charge structure passed on to these customers would potentially complicate supply bills further at a time when there is pressure to simplify these.

For all these reasons, we would be particularly against the introduction of LRIC approaches for 11kV and LV networks.

- *Currently the AC ICRP method starts from demand at time of WPD system peak demand. Use of this for price setting purposes is likely to cause hunting of the peak demand as users of the network seek to avoid the peak period. Currently we are considering using an average of the top 20 peak half hourly demands to define the input to the model. This sends a strong message to users to avoid periods likely to contribute to reinforcement of the system. Views on how to define the demands used in the model are welcome.*

We believe that discussions on this type of detail are best conducted within the framework of the joint DNO work so that consistency, where appropriate, can be established across all DNOs. On this particular issue, we note that National Grid's charging methodology continues to use three peaks (the "triad") for demand charging, following a charging review which also considered the option to increase the number of top demand half-hours to use. The proposal to use 20 peak half-hourly demands would introduce an inconsistency across the industry.

- *Parts of our system have a significant night peak. Should, and if so how should this be accommodated within the AC ICRP approach? Similarly reinforcement can be triggered by high generation output during periods of low demand – views on how to accommodate this are also welcome.*

Queries such as this further demonstrate the complexity of the proposed approach. There is a high degree of averaging in distribution charging at present and, in our view, this should continue in order to allow practicable application of use of system charges by suppliers.

- *Our connection charging methodology requires a contribution towards system reinforcement as part of the connection charge. This is not based on a physical boundary and hence is difficult to incorporate into the AC ICRP approach. Views on whether and if so how this can be incorporated are welcome.*

Connection charges currently contain a locational signal through the inclusion of a contribution towards system reinforcement. There is therefore no need, in our view, to try to incorporate such signals in this complex AC ICRP approach. To do so would potentially lead to double counting and there is no discussion in the consultation on how any inconsistencies in approach between the connection and use of system charges would be addressed.

- *Should EHV (site specific) charges be subject to averaging out of unused capacity or to scaling in general?*

It is difficult to comment on this as there is no information on how it would affect charges. As with the question on defining the peak period, we believe that discussions on this type of detail are best conducted within the framework of the joint DNO work. In this way, the issues can be actively debated at the DNO workshops and consistency, where appropriate, can be established across all DNOs.

- *Does the LRIC approach outlined above better achieve the licence objectives than the existing methodology?*

Our response to the similar question on the ICRP methodology is relevant here.

- *Are there further advantages or issues with the approach described?*
Our response to the similar question on the ICRP methodology is relevant here. Additionally, we believe this methodology is less well developed and relies more heavily on notional constructions of “future” costs, which could be challenged.
- *With the LRIC method, there is a need to allocate an ‘unused’ or non marginal charge. Is a universal £/kW or p/kWh best or should some other method be used?*
Our response to the similar question on the ICRP methodology is relevant here.
- *In terms of investment in the network, around 30% is associated with expansion whilst the other 70% is associated with replacement of system assets. Whilst replacement decisions can be affected by reductions in system loads, historic analysis shows this to be rare. Hence should the locational message from the LRIC approach be:*
 - *restricted to 30% of the charge ?*
 - *allowed to reflect whatever results from the model ? or,*
 - *be scaled up to reflect 100% of the charge ?*

Our response to the similar question on the ICRP methodology is relevant here.

- *The LRIC approach has three main parameters highlighted in that section. Are the approaches being used reasonable? In particular, how should parts of the network with zero or negative load growth be treated where change of the system assets for replacement purposes will occur before the assets are changed for reinforcement purposes.*
It is difficult to answer this question without information about the potential impacts and sensitivities of the different options. It appears to us that these are issues where different approaches could lead to significantly different charges for different users. In our view, a DNO should discuss the context and impact of different approaches rather than merely consult upon them “in theory”.
- *As highlighted there are difficulties in applying the method to 11kV and LV systems. Is either of the approaches suggested appropriate or should some other method be used?*
Our response to the similar question on the ICRP methodology is relevant here.
- *Currently the LRIC method starts from demand at time of WPD system peak demand. Use of this for price setting purposes is likely to cause hunting of the peak demand as users of the network seek to avoid the peak period. Currently we are considering using an average of the top 20 peak half hourly demands to define the input to the model. This sends a strong message to users to avoid periods likely to contribute to reinforcement of the system. Views on how to define the demands used in the model are welcome.*
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- *Parts of our system have a significant night peak. Should, and if so how should this be accommodated within the LRIC approach? Similarly reinforcement can be triggered by high generation output during periods of low demand – views on how to accommodate this are also welcome.*

Our response to the similar question on the ICRP methodology is relevant here.

- *Our connection charging methodology requires a contribution towards system reinforcement as part of the connection charge. This is not based on a physical boundary and hence is difficult to incorporate into the LRIC approach. Views on whether and if so how to incorporate this are welcome.*

Our response to the similar question on the ICRP methodology is relevant here.

- *If both the AC ICRP and LRIC approaches better meet the objectives, then which of the two better achieves them?*

We do not believe that either methodology better achieves the relevant objectives for the reasons set out in our response to the similar question in respect of the AC ICRP model. In our view, the case has not been proven for a move away from the current methodology.

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17th February 2006

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Dear Simon

Western Power Distribution Consultation on Potential Changes to the Use of System Charging Methodology

Thank you for the opportunity to comment on the matters raised in your consultation on potential changes to the WPD Use of System Methodology. We believe at this stage is not possible to form a view as to whether any of the proposals better meet the relevant objectives. This response will considers a number of general issues before commenting on each of the proposed models.

Generally

The responses received from this consultation are likely to inform not only the WPD decision making process but also Ofgem's view on any proposed modifications. Although most welcome, this consultative route is not an established process and should not be relied upon to be representative of industry opinion. Our view is that on substantive issues it should be Ofgem that manages the consultation process. A practical step towards ensuring a comprehensive consultation process would be to establish an open forum for the industry to discuss proposals such as those described here. This might most obviously be named the "Distribution Charging Methodology Forum" (DCMF).

The cost-reflective license objective referred to in the consultation notes the need to take account of implementation costs. In addition to these suppliers may also face implementation costs as a result of charging methodology modifications. If different DNOs modify their tariff structure in differing ways then the implementation costs for the supplier could be many times those seen by the individual DNO. Modifications likely to have a material change on either the level or structure of charges should have a substantial lead time to implementation so that suppliers can align their IT systems and manage their contractual positions with end-users thus reducing their overall costs.

All the charging methods outlined will involve taking actions to ensure that the DNO's allowed revenue is realised. This issue requires careful consideration and debate outside of this. The illustrative percentages of charges associated with unused capacity, and the percentage of costs attributed to asset replacement, emphasises the importance of this aspect.

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DRM

- The nature of the DRM model makes it unable to produce charges for generation on the same basis as demand.
- For demand customers the DRM has the advantage that a single model can be applied to all customers. Having differing models for different customer groups could lead to difficulties, in demonstrating cost-reflectivity and non-discrimination.
- It is important for transparency and predictability that models are published together with their methodologies. We note with interest that the DRM that WPD use can be published in full, and we look forward to receiving it in due course.

AC ICRP

- We would agree with the view that whilst locational signals in prices may have economic merit at EHV, there will be a level on a distribution network where applying locational prices becomes impractical.
- The issue of 'hunting the peak demand' is more likely to be a function of the output of any model than its input. End-users may react to messages explicit in their Supply tariff which may be driven by the Distribution tariffs that the Supplier incurs, but it is less clear whether end-users will seek to influence inputs into the model.
- The potential of tariffs sending out apparently perverse messages (high charges when there is spare capacity) is of obvious concern in this model.

AC LRIC

- The issues regarding the extent of locational prices and 'hunting the peak demand' noted in respect of the AC ICRP model will also apply to this model.
- In addition, there are references to figures used in the model- a demand growth rate of 1.6% and a multiplier of 1.5 relating to transformer reinforcement costs, that appear to be empirical in their derivation or their method of derivation is not given. If the models are significantly impacted by such underlying assumptions then it is essential that the source of such data is stated and when and by what means it will be updated.

On the final question of which of these two models better meets the relevant objectives, and whether they outperform the DRM, requires a greater level of detail before a definitive conclusion can be reached. We are appreciative of the fact that WPD has attempted to involve and inform the industry through this consultation.

If you wish to discuss our response, please contact me at the above.

Yours Sincerely

Andy Manning
Network Charging

**BOC COMMENTS ON CONSULTATION ON POTENTIAL CHANGES TO
THE USE OF SYSTEM METHODOLOGY
WPD CONSULTATION DATED 16 JANUARY 2006**

1 GENERAL REMARKS

BOC find it difficult to comment on the potential changes to the WPD Use of System Methodology without understanding the outcomes in terms of DUOS charges. On the face of it the changes do not look attractive in terms of cost reflectivity with respect to EHV customers.

BOC feels that if the present EHV customer prices do not match the output of the model used in the current methodology then WPD should consider returning to the previous approach used in the S Wales area. This was one of site specific charges which were built up by using identified the system assets used to deliver the electricity to the customer site.

BOC believes that any proposal for a change in methodology should be accompanied by a customer impact assessment and a cost benefit analysis.

2 SPECIFIC COMMENTS

2.1 AC ICRP methodology

BOC does not believe that treating demand and generation on a consistent basis should necessarily be considered an advantage. Demand and supply may have different requirements from the distribution system. Demand is less likely to respond to locational signals than generation.

ICRP allocates costs on the basis of the usage of the network. However, this seems to be a perverse inverse relationship whereby those on less used parts of the network pay more. If these “unused capacity” charge is averaged by charging a £/kW charge then this does not seem cost reflected.

BOC is not convinced that a priori the ICRP being similar to the transmission charging methodology is necessarily an advantage.

BOC would have concerns if WPD bring in changes because they believe this is what is expected of them and then only applying such changes to EHV customers.

BOC has concerns that a methodology which is based on forward looking charges when the investment in assets is split only 30% for system expansion when compared with 70% for system replacement. This does not look cost reflective.

2.2 AC LRIC methodology

BOC's views on the LRIC approach are similar to those of the AC ICRP approach.

The method seems to contain a number of simplifying assumptions and averaging approach. BOC believes that this would make the charges produced from this approach less cost reflective than asset specific charges for EHV customers.

Hugh Mortimer, 8 February 2006

WPD January 2006 Consultation Responses by e-mail

EDF energy – supply

Rather than comment in detail on the two different approaches suggested by WPD, I am confining my response to a general summary of what EDF Energy as a Supplier would look for in any future DUoS charging structure.

- The most important objective should be to ensure that DUoS charges should be transparent, predictable and easily understood.
- The split between fixed and variable elements should be directly and transparently reflective of costs.
- The methodology should be consistent but not necessarily the same methodology for Demand and Generation customers bearing in mind there must be no cross subsidy.
- We would wish to see the future structure of DUoS charges remaining the same for at least for the next 5 years to enable us to predict future costs and the impact on us and customers.
- The number of DUoS tariffs should bear relation to tariffs offered by EDF Energy and other Suppliers in the market.

SP Power Systems

Thank you for the opportunity to comment on your proposed changes to your Use of System methodology. It is obviously for WPD to bring forward changes to its methodology which it considers to better meet the relevant objectives. We do however, have the following observations.

We will be sending Ofgem a detailed response to the Bath paper. We do not, however, believe that their LRIC approach, which you also propose, produces cost reflective charges. For example, it is highly sensitive to load and generation growth assumptions. It also only produces charges which cover only c.10% of the revenues and it does not address costs associated with time of use. In our opinion this approach, in its current form, is unlikely to better meet the relevant objectives, based on our understanding of your existing methodology.

The approach considered in the consultation covers only a small proportion of WPD's charges. With this in mind it is difficult to see how WPD could move to a new methodology by April 2007, considering the number of outstanding issues.

We have not responded to the detailed questions raised in the consultation. We plan to address these and similar issues in the joint DNO work looking at the long term charging arrangements.

In summary, in our opinion the WPD proposals rely on an approach that does not adequately identify costs. However, we look forward to working with you as part of the joint DNO work to develop long term charging arrangements.

United Utilities

I am pleased to have the opportunity to respond to your recent consultation paper. WPD are to be commended for taking the initiative in engaging external assistance in the quest for an improved approach to DUoS pricing and for encouraging industry wide debate by publishing a review of the options.

As you know, we have also been working with a local university along similar lines and I look forward to sharing our experiences when we meet next week. The task of developing a new pricing methodology is extensive and the ENA workshop on 25 January helpfully explained the key steps in the process. For each DNO the challenge is to complete a review of each step in the chain. The three building blocks were quickly segmented into six work areas, and each of these will be made up of a number of separable tasks. The number of decisions to take is considerable and although some can be treated in isolation, others must be seen as part of a consistent philosophy. It would be quite inappropriate to belittle your excellent start to the consultation process, but it is immediately clear that it does not cover all aspects of a new pricing methodology. We therefore consider that your objective of completing the process by the summer of 2006 will prove over-ambitious, but this does not invalidate the early stimulus to debate.

I have one further general observation before addressing the detailed content of your paper. Our goal should be to develop a consistent theoretical framework, applied across all voltages, within which to establish our prices. However, within each stage of the process there must also be a checkpoint to consider any practical implementation constraints. These can often only be evaluated once some analysis has been done, and we would not therefore support the closing off of options without an assessment of the implications. (This would apply, among other issues, to the potential treatment of connection related costs).

Much, but by no means all, of your paper is related to what I would describe as the first module in a pricing methodology - the mechanism for attribution of network costs. We agree that this module should be based on forward looking costs and have found it interesting to consider the different approaches suggested by UMIST and University of Bath. These attach different weight to the differentiation of drivers of asset requirements between the time of use (and the interaction of uses at any time), the geographical location and extent of assets, the degree of 'spare capacity' within existing assets and the distinction between active and reactive power. The more variables that are added to the mix the more complex the model becomes. With complexity comes the possibility (likelihood even) of spurious accuracy in any modelling. We therefore see great merit in a review of the significance of including specific drivers. We have a number of technical questions about the detail of the models that University of Bath have developed that it may be worth exploring with you at a later date. For now, it is probably sufficient to acknowledge the value that we would expect to see in understanding the nature of incremental costs relating to changes in both generation and demand at distinct geographical locations. How much of this is worth reflecting into prices to suppliers and generators can only be decided after the analysis has been done.

The next step in the generic process is to determine the right costs to apply to the incremental assets identified in stage 1. Most approaches try to establish MEA values, but there are a variety of ways of doing this. Some have suggested using cost projections from the last price control review or the unit costs within that process. It is an interesting question whether to use only the costs of 'load related investment' divided by the extent of load growth or to also allow for replacement investment as well. Our current view is that it is unit costs consistent with network extensions or enhancements that should be used, but we can see the danger of discounting the effects of technological progress in the future. We are also concerned that some parties are looking only at capex, whereas the true incremental costs will also include the future stream of operating expenses triggered by the new investment. The bundle of costs that should be attributed on the basis of the network usage model should therefore include all costs that are triggered by incremental investment, including both direct and indirect opex as well as capex.

The third step is to establish the customer groups across which to attribute costs. This is an area where research has been far less extensive in the recent past and more work is needed to understand the customer groups with distinctly different patterns of network usage. Once these customer classes have been agreed, costs can be attributed on the basis of usage patterns, defined in terms that match the drivers of investment (likely therefore to be demand at times of, not necessarily coincident, system peaks, but also potentially covering fault levels and other network metrics).

The fourth element of the overall process is to develop yardstick costs for each customer group. This will bring together the network costs at each voltage level with other attributable costs, such as those related to customer service and billing. Some of these will be attributed on bases that are not related to the network usage matrix. However the aim remains the same - to try to identify the drivers of costs and to establish the increments of cost related to those drivers.

Next is the calculation of tariff components from the matrix of costs. The structure of charges will be a compromise between the billing parameters available (constrained, for example, by metering specifications) and the range of cost drivers identified in the cost assessment work. There has been considerable progress towards a standard framework of tariff components which should provide sufficient flexibility to allow prices to reflect the main elements of cost and to encourage customer response to the resultant economic signals.

Finally, there is a need to reconcile expected revenues to the limits implied by price controls. You seem to imply that this reconciliation should reflect only the potential variability of network capacity usage. This cannot be appropriate. As mentioned above, cost modelling needs to pick up more than the costs associated with network usage. Price control allowances are unlikely to exactly match forward estimates of incremental costs against any category of expenditure, and it is the 'total cost' that needs to be compared with allowed revenue.

One key issue to be resolved is the extent to which locational messages are necessary within a DNO pricing methodology. We believe that location is one of the main economic decisions that can be affected by price structures and levels. This implies that any cost models should be able to identify the extent of geographical variation in costs, leaving the option of reflecting significant differences in prices. Your paper suggests that this may not be practical for lower voltage DUoS charges, which implies that connection charges may need to be used to convey the locational message. There is a danger that conclusions on this issue will be reached on the basis of emotion rather than analysis and we would therefore recommend that the cost assessment embraces connection costs so as to inform future debate.

It is difficult to do justice to your consultation and the many issues it raises. I do hope, however, that you find this note of some value. I would be pleased to expand on any of our comments in greater detail if you wish.