Evaluation of WPD's proposed methodology for deriving charges for Barry power station

A REPORT PREPARED FOR CENTRICA

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Executive Summary

Western Power Distribution (WPD) has recently proposed changes to the way in which it charges users for using its extra high voltage (EHV) network. These changes represent the latest development in a long running project, initiated by Ofgem, to harmonise the methodologies used by Distribution Network Operators (DNOs) to calculate the charges for users of the networks. These WPD proposals are currently the subject of an Ofgem consultation.

Amongst other things, the proposed methodology will introduce charges to generators that have been connected to the EHV network prior to 2005 and, to date, have been exempted from paying charges because typically they paid an upfront fee at the time of connection in lieu of use of system charges.

Centrica is the owner of Barry power station, a 230 MW combined cycle gas turbine (CCGT), which connected to WPD's EHV network in 1997. As such it is potentially very materially impacted by WPD's proposals.

In light of this, Centrica has commissioned Frontier Economics to evaluate the changes proposed by WPD. This report presents our findings. In it we assess the extent to which the proposed methodology meets the principles that Ofgem have in the past indicated that charging methodologies should meet. In particular, we focus on whether the charges derived by the methodology for large generators such as Barry are in keeping with the principles.

Our overall conclusion is that we do not believe that the generic methodology used to calculate both demand and generation tariffs for EHV customers, is appropriate for a very large generator that accounts for about 90% of the installed generation capacity on the South Wales network. Specifically, we have four key concerns regarding the way in which WPD has derived charges for the Barry Power station.

Our first concern relates to the fact that the methodology does not derive a charge that is reflective of the costs that Barry imposes on the network. WPD has selected the Long Run Incremental Cost (LRIC) model as the basis for the charges proposed for Barry. Fundamentally, this methodology calculates charges by analysing the impact on the network of small increments of demand and generation, by node. In those parts of the network where there is little spare capacity, increments of generation tend to trigger significant charges.

Barry triggered (and indeed paid for) significant reinforcement at the time of connection. The immediate part of the WPD network to which Barry is connected has therefore been sized to allow Barry to export an amount of power equal to the maximum set out in the connection and use of system agreement. Understandably, therefore, there is little spare capacity in that part of the network at present (or at any time since connection) – indeed it would raise questions regarding the efficiency of the network operator if there were. However, one upshot of this lack of capacity is that it results in a unit charge (set on a £/kVA basis) for a small (0.1MW) increment in the generation capacity at the node at which Barry is connected that is very high.

If Barry could opt to operate in 0.1MW capacity "steps" this would indeed be a cost reflective signal to send Barry power station. However, in practice, the economics of the plant are such that it faces the binary decision of either keeping the plant open at its registered capacity or completely closing it down. As a result of this, extending the cost signal derived from incrementing a 0.1MW of generation across the entire 230 MW capacity of the plant results in a signal that hugely overstates the costs that Barry imposes on the network.

Our second concern relates to the assumptions used by WPD in the methodology itself. Embedded within the heart of the methodology is a critical assumption that network usage will grow at 1% per annum in perpetuity. This applies to both growth in demand and growth in generation. This "exogenous" 1% growth assumption is required as the methodology breaks down if growth is very low (as derived tariffs tend to infinity as the growth rate tends to zero). There might be some sense in assuming a 1% growth rate on the demand side – for example this could reflect the underlying growth in the demand on the HV and LV networks (although even here we would question this given that we now understand that there is expected to be a reduction in demand). However, the lumpy nature of generation growth (particularly on the EHV network) means that the use of a smooth 1% growth rate is wholly inappropriate – and significantly reduces the cost reflectivity of the tariffs that are derived.

To be truly cost reflective, use of system charges should distinguish between areas of the network where, everything else being equal, high growth is expected (and therefore spare capacity is likely to be limited) and areas where low growth is expected (and therefore tariffs should indicate that there is likely to be more spare capacity in this area of the network). However WPD's methodology does not allow the use of the most accurate "forward looking" assumptions (such as those set out in the long term development statement) and as a consequence, distorts the locational signals that the methodology purports to derive.

Our third concern is that, as well as lacking cost reflectivity, WPD's methodology produces tariffs that are hugely volatile in the case of Barry and materially influenced by subjective engineering assessments. We understand that the 2009/10 charge for Barry as calculated by the methodology would have been £4.2m whereas the tariff calculated on a like-for-like basis for 2010/11 would have been £2.2m – nearly 50% lower. Given such a large change one would expect to have seen a very significant change in the demand-supply fundamentals in the Barry area – for example a large source of demand might have connected in the region. However, we understand that the swing in charges resulted from a small change in the demand assumptions in one part of the network and by a change in the engineering assessment of line rating of one of the lines serving

Barry. It therefore appears that the methodology is neither transparent or predictable – and therefore contrary to the principles for charging methodologies laid down by Ofgem itself.

Partly in recognition of the deficiencies on the methodology when applied to large generators, WPD has proposed the application of a number of "fixes" – notably capping charges at branch level and removing sole use assets. Our final concern is that these fixes merely demonstrate the fact that the charges derived are not cost reflective when applied to a large plant and, moreover, there is no reason to believe that this proposed fix results in charges that are more or less cost reflective than now.

1 Introduction

This report by Frontier Economics has been commissioned by Centrica. It provides an evaluation of Western Power Distribution's (WPD) most recent proposed modification to its charging methodology[1]. Amongst other things, WPD's modification proposes to introduce changes to its charging methodology at the Extra High Voltage (EHV) level to commence from 1 April 2010 and is currently the subject of an Ofgem consultation[2].

The proposed methodology changes will introduce charges to generators that connected to the EHV network prior to 2005 and to date have been exempted from paying charges. Centrica has a significant portfolio of generation connected to electricity distribution networks and is the owner of Barry power station, a 230MW combined cycle gas turbine (CCGT) plant that connected to (what is now) the WPD network in 1997.

As such the proposed changes to the WPD charging methodology would mean that Barry power station would for the first time pay a use of system charge for using the WPD network. These charges would be in addition to the charges that the developers (AES) paid when Barry connected to WPD's network in 1997. These charges, which came to £4.9 million, were at the time considered to be in lieu of future payments of use of system charges. These terms of connection were novated to Centrica when it acquired the station from AES in 2003.

In these circumstances, Centrica has asked Frontier to investigate the extent to which WPD's proposed methodology meets the criteria typically used to judge the efficacy of a charging methodology, particularly with regard to large generators such as Barry power station. This report presents our findings.[3]

We have divided our report into four further chapters

- Chapter 2 provides background to the current debate on charges for the EHV network, detailing the regulatory context and describing some of the key characteristics of Barry power station relevant to this debate;

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1 Amendment proposal: WPD/Wales/West/UOS016 "Amendment to Use of System Charging Methodology to revoke the LV/HV DRM Methodology from the Implementation Date of the CDCM", 11 January 2010

2 Letter from Rachel Fletcher to distributors, suppliers, generators customers and other interested parties dated 14 January 2010 "Consultation on Western Power Distribution's modification proposal (WDP/Wales/West/016) to introduce changes to its charging methodology at extra high voltage (EHV) level from 1 April 2010."

3 Frontier Economics has previously had material published on the subject of electricity distribution charging methodologies. See "Review of distribution use of system charging methodology" at http://www.scottishpower.com/uploads/FrontierEconomicsG3DUoSChargesFinal250308.pdf which sets out our views on another proposed charging methodology.

- Chapter 3 sets out our understanding of Ofgem's high level objectives for setting network tariffs, particularly focussing on the objectives and rationale for charging EHV generation;

- Chapter 4 describes our understanding of the LRIC methodology adopted by WPD for charging Barry power station; and

- In Chapter 5, we evaluate the WPD's LRIC methodology in view of the charges proposed for Barry power station.

We have based our analysis primarily on the following sources:

- WPD's Amendment proposal WPD/Wales/West/UOS016 – Amendment of Use of System Charging Methodology to revoke the LV/HV DRM methodology from the implementation date of the CDCM, published 11 January 2010

- Ofgem's consultation on WPD's modification proposal, published 14 January 2010

- WPD's Statement of Use of System methodology for Western Power Distribution (South Wales), published in March 2009

- Ofgem's 1 October 2008 Decision Document in which it sets out the high level principles that its proposed EHV methodology should encompass;

- Ofgem's 2005 consultation document on the longer term framework for the structure of electricity distribution charges

In addition we met with WPD on 21 January 2010 to discuss its methodology and its proposed modification.

2 Background

In this chapter we briefly describe the regulatory background to the current debate on EHV charges for the WPD network and then go on to detail some of the key characteristics of the Barry power station.

2.1 Regulatory background

WPD's proposed methodology change is the latest development in a long running project, initiated by the regulator, to harmonise the methodologies used by distribution network operators (DNOs) to derive use of system tariffs for users of their networks.

To date there has been significant development in the harmonisation of the methodology used to derive tariffs for use of the distribution network below the 22kV level (the High Voltage (HV) and Low Voltage (LV) networks) and a new charging methodology for the voltage levels is due to be implemented from 1 April 2010. However, the implementation of a methodology at the Extra High Voltage (EHV) level (that is for use of assets above the 22kV level) has been more problematic. It has not been possible for the all interested parties to agree on which methodology should be adopted for the derivation of EHV tariffs. As such, in February 2009, Ofgem agreed that two possible methodologies could be adopted by the DNOs – either the Long Run Incremental Cost (LRIC) pricing model (as currently used by WPD) or an alternative approach known as the Forward Cost Pricing model that had been developed by a number of other DNOs[4]. However, this failure to agree a single proposed approach has caused a delay in implementing the new tariff methodology at the EHV level. It is currently hoped that a new "semi-harmonised" EHV methodology will be in place for 1 April 2011[5]

Concurrent to these aims to harmonise the charging methodologies, Ofgem has also stated that generation units connected at the EHV level that have hitherto been exempted from paying use of system charges should start paying charges from 2010. Generators that connected to the EHV network before 2005 are currently exempt from paying use of system charges since they typically paid an upfront fee at the time of connection in lieu of future use of system charges. Generators that connected after 2005 paid no such up front fee but are instead liable for use of system charges.

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4 Specifically, Scottish & Southern Energy Networks, ScottishPower Networks and Central Networks.

5 The details of the new EHV methodology are currently being developed through the Energy Networks Association (ENA).

Until very recently there has been a lack of clarity about whether the DNOs would implement this Ofgem policy proposal for 1 April 2010 given that there is as yet no harmonised charging methodology at the EHV level.

On the basis of the WPD proposal, it would now seem that it is the intention for the DNOs to extend their current charging methodology to EHV generators that were connected to the network before 2005 from 1 April 2010. In the context of WPD's network, this is particularly germane as it is the only DNO to have recently implemented a new charging methodology for the EHV network. WPD implemented its LRIC methodology in 2007 following Ofgem's decision not to veto its proposals.[6]

Although not clear yet, it seems that other DNOs will also now develop their current methodologies so that generators that connected before 2005 are required to pay charges.

Therefore, WPD's motivation for raising the current use of system modification 016 is that it allows charges to be derived, on the basis of some form of its LRIC methodology, for generators that connected to its EHV network prior to 2005. This is in line with Ofgem's stated policy objective that pre-2005 generators should no longer be exempted from paying use of system charges.

2.2 Barry Power Station

For Centrica, these proposed changes to the treatment of EHV generators that connected prior to 2005 have a potentially very material impact. It owns Barry power station, which is a 230MW Combined Cycle Gas Turbine (CCGT) sited near Cardiff.

Barry power station began commercial operation in 1998 following connection to SWALEC's (now WPD's) 132kV network. At the time of connection the developers (AES) paid:

- a charge of £4.3m to fund the reinforcement of the 132 kV network in the area; and
- a charge of £560,000 which represented the capitalised cost of operation and maintenance of the distribution network assets.

These charges were, at the time, considered to be in lieu of future payments of use of system charges. These terms of connection were novated to Centrica when it acquired the station from AES in 2003.

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6 Ofgem's reasons for non veto are set out in a letter to WPD's Company Secretary "Decision in relation to Western Power Distribution's proposal to modify their Electricity Distribution Use of System Charging Model - Ref:WPD/WALES/WEST/UOSOOZA" on 1 February 2007.

Barry also currently pays two annual charges to WPD, one is a £10,000 regular fixed charge to compensate it for the costs of scheduling the plant and the second is a standard electricity distribution tariff that it pays for using the network in as a demand customer (for example, when the Barry plant itself is not operating).

Given its relatively large size, Barry power station operates very much like a transmission connected power station:

- The electricity produced by Barry predominantly flows up onto the transmission network: the two local Grid Supply Points at Aberthaw and Cardiff South are both major exporters onto the transmission grid.
- Barry interacts with National Grid like a transmission connected generator – submitting notifications of intended production.
- Barry brings benefits to the wider electricity grid by reducing the need for investment in the transmission network – as is evidenced by the negative TNUoS charge levied on the power station under National Grid's transmission charging regime.

3 Charging objectives

In this chapter, we set out our understanding of the objectives and principles that a Distribution Use of System (DUoS) charging methodology should seek to embody. To this end, we have reviewed both the relevant objectives for DUoS charges set out in DNOs' electricity distribution licences and a number of consultation documents issued since 2005 on the structure of charges.

When deciding whether to veto a proposed modification to an existing DUoS charging methodology, Ofgem's Authority must assess the extent to which these changes would better facilitate the achievement of a number of objectives. These objectives are set out in Standard Licence Condition 13, paragraph 3 of the electricity distribution licence. In summary, these objectives state that a Distribution Network Operator (DNO) must adopt a charging methodology for deriving use of system tariffs that:

- facilitates the discharge by the licensee of the obligations imposed on it;
- facilitates competition in the generation and supply of electricity, and does not restrict, distort, or prevent competition in the transmission or distribution of electricity;
- results in charges which reflect, as far as is reasonably practicable (taking account of implementation costs), the costs incurred by the licensee in its Distribution Business; and
- as far as is reasonably practicable, properly takes account of developments in the licensee's Distribution Business.

These "relevant objectives" as defined above are relatively high level and Ofgem has, since 2005, sought to clarify the key characteristics that a charging methodology should incorporate. It has published a number of consultation documents on the subject:

- In its **May 2005 consultation** on the longer term framework for the structure of electricity distribution charges,[7] Ofgem outlined five high-level principles for distribution charges to "sit alongside" the four relevant objectives set out in DNOs' licences. These five principles are:
  - cost reflectivity;

[7] See Ofgem document "Structure of electricity distribution charges. Consultation on the longer term charging framework". May 2005

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/10763-13505.pdf

  - simplicity;
  - transparency;
  - predictability; and
  - the facilitation of competition.

- Ofgem reiterated these five high-level principles in its **July 2008 decision** on the common methodology for Use of System charges[8]. It also sought to provide further guidance on how DNOs should operationalise these principles:

  1. include all relevant information;
  2. apply to both demand and generation;
  3. reflect all significant cost drivers;
  4. minimise the distortion to price signals where any adjustment of scaling of charges is necessary to ensure recovery of allowed revenue;
  5. recognise incremental costs and benefits on a forward-looking basis by virtue of users' use of the distribution system;
  6. ensure that charges for EHV users vary by location and utilise power flow modelling at EHV level; and
  7. be transparent and predictable to allow users to estimate future charges.

While numerous, for ease of exposition we aggregate these guiding principles into two broad categories. These are that:

  - network charges should be **cost reflective** as far as is practicable; and
  - network charges should be **simple**, **transparent** and **predictable**.

In its July 2008 decision document[9] Ofgem observes, correctly in our view, that there is an "inevitable tension" between cost reflectivity on the one hand and simplicity, transparency and predictability on the other. It emphasises that the development of a use of system charging methodology is therefore "a balancing act between a number of competing principles".

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8 See Ofgem document "Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements", July 2008

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/FINAL%20July%20consultation%20letter_22_07_08.pdf

9 Ibid

In what follows, we draw on this Ofgem documentation in more depth to set out our understanding of what each of these two sets of high-level principles involves[10].

3.1 Cost reflectivity

In its July 2008 decision on the common methodology for Use of System charges, Ofgem states that one of the key goals of its long-running structure of charges project has been "to ensure that DNOs provide appropriate incentives to their customers to encourage efficient use of their networks".[11] We understand that Ofgem's conception of cost reflectivity relates directly to this goal. Charges should be calculated so as to reflect all significant cost drivers (principle 3, above), but they should also be "forward-looking" (principle 5). In other words, instead of simply billing customers for the costs that they have historically imposed on the network, charges should seek to send customers a "price signal" (principle 4) about the costs that their decisions today could impose on the network in the future. In this way, customers will internalise the costs associated with their actions when making decisions about their use of the distribution network. We understand that it is this that Ofgem envisages will help DNOs to "provide appropriate incentives to their customers" and "encourage efficient use of their networks".[12]

It is worth noting also that Ofgem envisages that the charges should apply to both demand and generation (principle 2). In this context, generation charges might be negative in that the existence of a generating unit sited at particular location on the network might negate the need for costly network reinforcement and therefore reduce overall costs for the network operator.

A further cost reflective feature that should be incorporated at the EHV level is that charges should vary by location (principle 6). Combined with the other principles, this could be taken to imply that charges should be low in areas of the network where there is ample spare capacity and, conversely, that charges should be high where there is limited spare capacity.

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10 The reference to the facilitation of competition in Ofgem's 2005 document is an interesting one. We assume it pertains more to the fact that if charges are unpredictable, opaque and volatile this might serve as a barrier to entry in to the retail market – new entrants might have to expend more resources to understand how charges are determined so as to evaluate their final tariffs to customers. This issue is less relevant for the EHV network as typically EHV customers are not served by bundled tariffs – instead EHV customers' charge is passed through. Thus we do not consider this criterion further in this document.

11 Quoted from Ofgem's July 2008 decision document

12 We assume here that by an "efficient" outcome, Ofgem means a state of the world where a network user decides to locate (or increment demand for use of the network) at a particular network location if and only if the benefits associated with that decision outweigh the economic costs.

3.2 Simplicity, transparency and predictability

Alongside the need to make charges cost reflective, Ofgem has also consistently recognised the need for charging methodologies to be:

- sufficiently **simple** at the point of use for network users to understand how their charges are derived;
- **transparent** with regard to the steps used to derive the tariffs and assumptions used; and
- **predictable**, in that users should be able to understand how charges might evolve over time.

In its May 2005 consultation paper, Ofgem emphasises that having a simple and transparent methodology that produces reasonably predictable charges is also important for achieving an efficient pattern of network investment. On the one hand, the principle of cost reflectivity dictates that there should be at least some variation in charges over time in response to changes in the forward-looking costs associated with network use. However, Ofgem emphasises that predictable charges are also important in facilitating efficient network use, since:

"*long term decisions will be based on expectations of future costs, rather than solely on current charges, so it is important that future charges are predictable, as far as possible, and that reasonable expectations are not overturned without good reason.*"

Ofgem's insight here is an important one, since in practice many network users are not footloose and therefore need to take a long-term view when making decisions about where to locate. For example, a planned power station would require a substantial capital outlay, after which it would be committed to accessing the network from its chosen network location (and, assuming it connected to the network after 2005, paying the DUoS charges associated with that offtake point) for the duration of its life. In order to make an informed decision about where to locate, therefore, the generator must be able to form a view about the long-term development of DUoS charges at each potential network location. Therefore:

- If charges are volatile and unpredictable, then the current year's DUoS charge will contain very little useful information about how charges will develop in the future. In other words, methodologies that generate volatile and unpredictable charges will fail to provide long-term network users with a useful signal about where to locate.
- If a lack of predictability dilutes the ability of charges to send forward-looking locational signals, a lack of simplicity and transparency will compound the problem:

- If the charging methodology is opaque and highly complex, it will be difficult for long-term network users to understand the key drivers of DUoS charges.
- This in turn will make it difficult for the users to understand how charges might develop in different scenarios and thereby draw conclusions about the risks to which they would expose themselves by locating at different parts of the network.

3.3 Ofgem's rationale for introducing charges for distributed generators that connected pre-2005

Under the charging arrangements for 2009/10, generators that connected to WPD's network before April 2005 do not pay DUoS charges. However, WPD's modification proposal of 11 January 2010 seeks to strip these pre-2005 customers of this right and start levying DUoS charges on all generators from April 2011[13] as per Ofgem's proposed policy.

We assume that Ofgem's proposals to include pre 2005 connected generators originate from a desire to increase the efficiency of network use at the 132 kV level. It is theoretically conceivable that the absence of a DUoS charge for pre-2005 generators could result in the inefficient use of network resources. As well as influencing siting decisions, a cost reflective price signal might also influence closure decisions. For example, consider a scenario in which there is a sudden and unexpected drop in demand on one part of the network. As a consequence, local generation might start driving the need for network reinforcement. In extremis, the costs associated with reinforcing the network might be so high that it would be more cost-effective simply to scale back generation at that location. However, in the absence of a forward looking and cost reflective DUoS charge, the DNO has no mechanism for incentivising the generator to do this. As a result, the DNO would be obliged to reinforce the network and pass the associated costs down to the consumer. This, we presume, is Ofgem's rationale for introducing DUoS charges for generators that connected to the network before 2005.

Therefore charging all existing network users could, in theory at least, enhance efficiency. However, the argument assumes that WPD's proposed DUoS charging methodology would be capable of sending price signals to pre-2005 generators that better reflect the forward looking costs that they are imposing on

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13 Western Power Distribution, "Amendment of Use of System Charging Methodology to revoke the LV/HV DRM Methodology from the Implementation Date of the CDCM", 11 January 2010:

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/wpdmodificationrequest%20016.pdf the network than the current approach. As we demonstrate in Chapter 5, we have serious doubts about the ability of WPD's methodology to send large generators such as Barry an appropriate signal. Before explaining these concerns, however, we need first to set out our understanding of how WPD's methodology would calculate charges for such generators. This is the subject of the next chapter.

4 WPD's LRIC methodology

In this chapter, we set out in detail our understanding of WPD's LRIC methodology for calculating EHV tariffs for both demand and generation customers. The chapter has three sections:

- First, we set out our understanding of how WPD's existing LRIC methodology calculates charges for EHV demand customers and post-2005 EHV generators. This description is based on the information provided by WPD in its methodology statement, in the appendices to Ofgem's decision document of 1 October 2008,[14] as well as subsequent discussions with WPD.
- Secondly, we describe some of the revisions to this methodology that WPD put forward in its modification proposal of 11 January 2010.
- Finally, we describe our understanding of what the methodology and its revisions imply for the charge that Barry power station would face.

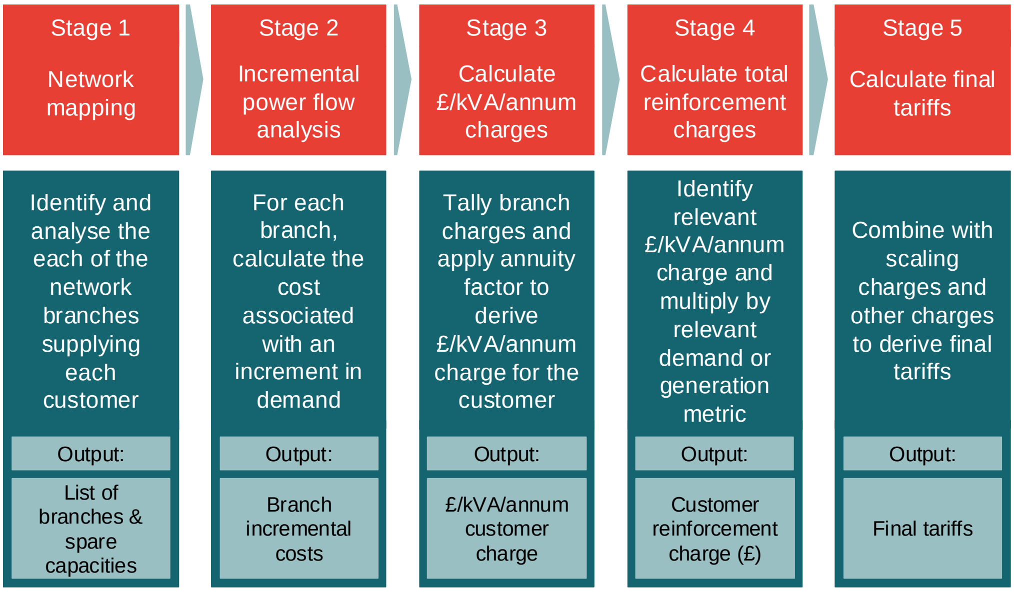
4.1 Overview of the existing WPD LRIC methodology

WPD's LRIC methodology is designed to generate a set of reinforcement cost charges for generation and demand customers. The methodology calculates separate demand and generation charges at each node on the network. These charges reflect the reinforcement costs that each user would impose on the network by permanently incrementing demand by 0.1MVA or permanently incrementing generation by 0.1MW.

At a high level, both demand and generation charges are calculated in five stages, as set out in Figure 1 below:

[14] '*Decision Document: Delivering the electricity distribution structure of charges project*', Ofgem, 1 October 2008

Figure 1. Overview of WPD's existing LRIC methodology



Source: Frontier Economics

As Figure 1 illustrates, the proposed methodology would calculate tariffs in the following stages.

- First, the methodology identifies and analyses the branches responsible for supplying each customer.
- Secondly, power flow analysis is used to identify the incremental costs that each customer would impose on each of these branches if the customer were to increment its demand for use of the network by 0.1MVA.
- Thirdly, the relevant branch incremental costs are added together to produce a total incremental cost for each customer. This incremental cost is converted to a £/kVA charge rate and then annualised to produce a £/kVA/annum charge rate.
- Fourthly, these £/kVA/annum charge rates are combined with the relevant customer demand information to derive a total reinforcement charge for each customer.
- Finally, these reinforcement charges are combined with scaling charges and other charges to derive final tariffs.

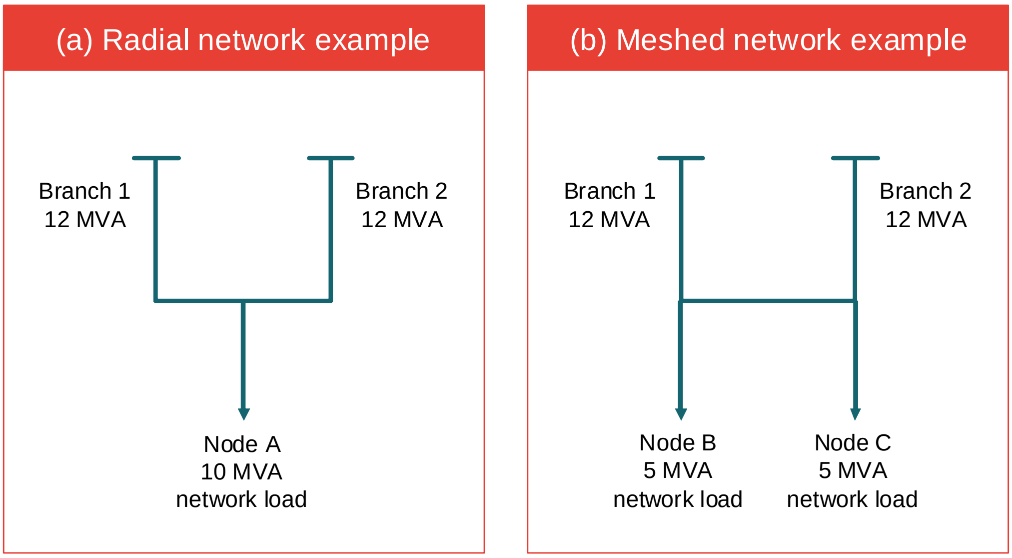
In what follows, we discuss our understanding of each of these five stages in detail.

4.1.1 Stage 1 – network mapping

To begin with, the methodology constructs a map of the existing network, identifying the branches responsible for supplying each node, along with their asset capacities. For each branch, the methodology then calculates the power flows passing over the assets of the distributor's network under existing demand conditions. Each branch's spare capacity is then calculated by subtracting existing power flow from existing asset capacity.

We illustrate this concept with two examples, set out in Figure 2 below (these examples are based on the stylised example set out in Appendix 1 of WPD's March 2009 charging methodology statement for South Wales).

Figure 2. Examples of a radial and meshed network



Source: Adapted from example provided in Appendix 1 of Statement of Use of System Charging Methodology for Western Power Distribution (South Wales) plc (March 2009)

- In the **radial** network illustrated in Figure 2(a), the demand customer at Node A is supplied by two branches. Power flow on each branch is 10 MVA / 2 = 5 MVA. Spare capacity on each branch is therefore 7 MVA. If there is an outage of Branch 2 then the contingency flow in Branch 1 is 10 MVA against the intact flow of 5 MVA, giving a security factor of 2.

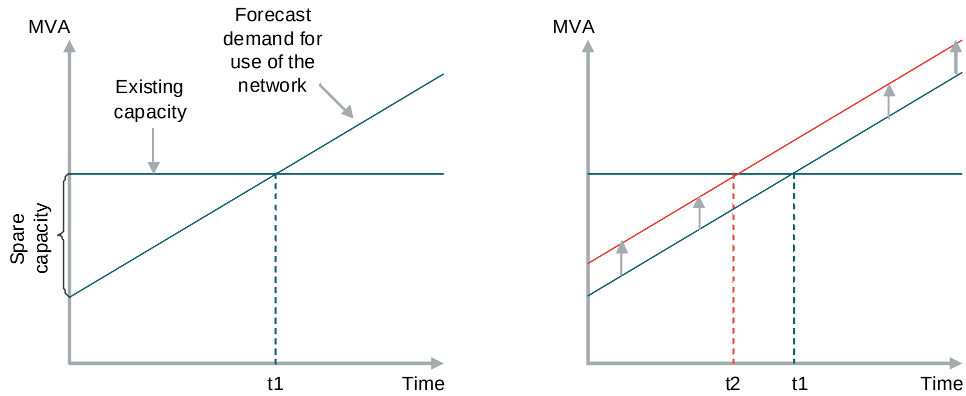
- In the **meshed** network illustrated in Figure 2(b), two branches serve two demand customers at Nodes B and C. Again, power flow on each branch is 5 MVA. Spare capacity on each branch is therefore 7 MVA. Again, if there is an outage of Branch 2 then the contingency flow in Branch 1 is 10 MVA against the intact flow of 5 MVA, giving a security factor of 2.

4.1.2 Stage 2 – incremental power flow analysis

The methodology now hypothesises that the customer permanently increments demand by 0.1MVA (or 0.1MW in the case of a generator) and asks what additional costs this would impose on each branch of the network. We understand that the choice of 0.1MVA as an increment was made on the basis that it would cover most transformer sizes.

At first glance, one might suppose that the reinforcement costs associated with this hypothesised increment would frequently be zero: a small increment in demand for use of the network will not impose immediate reinforcement requirements on the network unless there is very little spare capacity on the relevant branches supplying the customer. However, assuming that demand or generation would continue to grow in the absence of such an increment, the increment could still be thought of as imposing an indirect cost on the network, insofar as it will bring forward the date at which reinforcement of the network will be required. Figure 3 illustrates this concept.

Figure 3. Illustration of the proposed methodology's incremental cost concept



Source: Frontier Economics

The left-hand diagram illustrates the baseline scenario. To begin with, there is ample spare capacity. However, forecast growth in demand for use of the network (implied by the upward sloping curve) is such that reinforcement will be required at t_1. The right-hand diagram illustrates the effect of one customer permanently incrementing its demand for use of the network by 0.1MVA (or 0.1MW if it is a generation customer): this shifts the network demand curve up and brings forward the projected reinforcement date from t_1 to t_2. The future reinforcement cost in present value terms therefore increases. Therefore the incremental cost of a permanent 0.1MVA increase in demand is the difference between the present values of the reinforcement cost at time t1 and time t2.

The methodology uses this approach to calculate incremental costs for each of the relevant branches.

4.1.3 Stage 3 – calculate £/kVA/annum charges

Having calculated the long run incremental costs for each of the relevant branches that serve the node, the methodology then adds together these costs to derive the total 'long run incremental cost' associated with the 0.1MVA increment in demand for use of the network at that node.

Use of System charges will be levied every year. Consequently, if a customer decides to increment demand by small amount in year 1, it will pay a Use of System charge for that increment in all future years. If the full £/kVA charge were levied each year, the net present value of this future stream of charges would be far higher than the cost that the increment actually imposes on the network. In other words there would be over-recovery relative to the cost of reinforcement.

For this reason, the LRIC methodology spreads the £/kVA charge across a fixed number of years. To do this, the methodology applies an annuity factor which converts the £/kVA customer charge to a £/kVA/annum charge. The annuity period is set to 40 years, which we understand to be the typical economic life of a network asset. Assuming a 6.9% discount rate, the annuity factor is approximately 0.07. In other words, the customer pays about 7% of the total incremental cost charge each year.

4.1.4 Stage 4 – calculate total reinforcement charges

Stages 1 to 3 are repeated using peak and off-peak demand data to derive both peak and off-peak £/kVA/annum charges for the customer.

Stage 4 of the methodology then combines these peak and off-peak £/kVA/annum charges with peak and off-peak customer kVA demand estimates to derive a set of reinforcement charges for generation and demand customers at the node. The appropriate generation and demand charges depend on whether peak or off-peak network conditions drive reinforcement, as is illustrated in Figure 4:

Figure 4. Procedure for calculating total reinforcement charges

	Demand charges	Generation charges
Peak network demand conditions drive reinforcement	Peak incremental cost X Peak charging demand	-1 X (Peak incremental cost) X Level of demand expected to contribute to network security
Off-peak network demand conditions drive reinforcement	-1 X (Off-peak incremental cost) X Off-peak charging demand	Off-peak* incremental cost X Agreed export capacity

Source: Frontier Economics

* In its October 2008 decision document Ofgem states that, when off-peak network conditions drive reinforcement, generation charges are to be calculated by multiplying agreed export capacity by **peak** incremental cost. We have assumed that this was a typing error and that Ofgem's actual intention is to multiply agreed export capacity by **off-peak** incremental cost.

We assume that the rationale for this pattern of charges is as follows:

- If reinforcement of the network is required because there is insufficient capacity to meet that node's peak demand, then
  - charges should seek to discourage demand customers from locating at the node – as further demand will increase network costs; and
  - seek to encourage generation to site at the node if that generation reduces or delays the requirements for future distribution network investment. In these circumstances, and to the extent that the source of generation is reliable, then charges might be negative if this reflects the network reinforcement costs foregone by inducing generators to locate at the node.
- By contrast, the logic reverses if reinforcement is required to meet capacity requirements when demand at that node is off peak. In other words, when there is insufficient demand to consume generation at that node and insufficient network capacity to export the electricity to other parts of the

network then further incremental generation at that node means that additional network reinforcements must be undertaken. In these cases:

- charges should encourage demand customers to locate at the node as this reduces the need for network reinforcement; and
- generator charges should be higher than on other parts of the network so as to ensure that generators making siting decisions recognise that (from a generation perspective) there is little spare capacity on this part of the network.

4.1.5 Stage 5 – calculate final EHV tariffs

In Stage 5, the network reinforcement charges are combined with scaling charges (for revenue reconciliation purposes) and other charges in order to derive final customer tariffs.

Specifically, the calculation of final EHV tariffs would combine the LRIC charges calculated in Stages 1 to 4 of the methodology with a number of other charges, namely:

- sole-use asset charges (unless the costs for sole use assets have already been paid as part of a connection charge);
- network rates and NGET exit charges; and
- reactive power charges (for customers with a power factor worse than 0.95).

Next, these charges are combined with a scaling charge to allow the DNO to recover its allowed revenue.

These steps yield a set of total, site-specific EHV demand and generation charges, which are then used to calculate final tariffs.

4.2 Revisions to this methodology in WPD's latest modification proposal

In its modification proposal of 11 January 2010, WPD proposes to start using its LRIC methodology to derive Use of System charges for pre-2005 generators, beginning in April 2010. However, this forms just one element of a package of modifications included in the proposal. Two modifications in particular are likely to have significant implications for Barry power station:

- First, WPD proposes to introduce a **"capping arrangement"** to restrict EHV customers' charges to their asset value. Under this proposal, Stages 1 to 3 of the methodology remain unchanged, producing a £/kVA/annum LRIC charge for each relevant network branch. Now, however, WPD propose to cap each branch's LRIC charge at the level of an annuity of the asset value for that branch.

- Second, WPD proposes to **exclude certain branches** from the LRIC charge calculation for pre-2005 EHV generators that paid a deep connection charge. Specifically, WPD would to levy no charges for (i) sole-use assets and (ii) any branches that were paid for by the connection charge.

We discuss these proposed modifications in more detail in the next chapter.

4.3 Proposed charges for Barry Power Station

Over the last six months, WPD has published a series of documents proposing charges for Barry power station and other network users from April 2010. Table **1** below sets out how this proposed charge for Barry has evolved.

Table 1. The recent evolution in the DUoS charge proposed for Barry

Proposed charge	Year to which charge would apply	Scaled to allow revenue reconciliation ?	Includes capping arrangements ?	Excludes certain branches ?
£4,232,595	2009/10	No	No	No
£2,178,486	2010/11	No	No	No
£840,856	2010/11	No	Yes	No
£648,717	2010/11	No	Yes	Yes

Sources: WPD's amendment proposal, published 11 January 2010; Ofgem's consultation on WPD's modification proposal, published 14 January 2010

As **Table 1** makes clear, the DUoS charge that WPD is proposing to levy on Barry power station has undergone four stages of evolution in recent months:

- First, in its modification proposal of 26 August 2009,[15] WPD submitted a "proposed charge" of **£4,232,595** for Barry power station for 2009/10.

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15 See WPD, "Amendment of Use of System Charging Methodology to revoke the LV/HV DRM Methodology from the Implementation Date of the CDCM ", 26 August 2009

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/WPD%20UoS%20Modification%20Report%20013_2009.pdf

- By contrast, in its modification proposal of 11 January 2010, WPD set out no fewer than three alternative DUoS charges for Barry for 2010/11:
  - In the absence of any capping arrangements or the exclusion of branch assets paid for as part of its deep connection charge, Barry would face a total DUoS charge of **£2,178,486** for 2010/11. Interestingly, this is barely 50% of the equivalent charge for 2009/10.
  - Once capping arrangements are introduced, Barry's charge falls by more than half again to **£840,856**.
  - Finally, once branch assets that Barry paid for as part of its deep connection charge are also excluded from the calculation, the charge falls further still to **£648,717**. We understand that this is the charge that WPD is actually proposing to levy on Barry in 2010/11.

We confirmed the interpretation of these proposed charges at a meeting with WPD on 21 January 2010. During this meeting, WPD also explained that:

- the reduction in the proposed charge from **£2,178,486** to **£840,856** was driven by three of the branch assets serving Barry power station having their charges capped to the annuity of their asset value; and that
- the further reduction in the proposed charge from **£840,856** to **£648,717** was driven by the exclusion of two of the branch assets serving Barry from the calculation on the grounds that these had already been paid for as part of Barry's deep connection charge.

5 Assessment of WPD's LRIC methodology

In this chapter, we evaluate the extent to which WPD's LRIC methodology for deriving EHV generator charges satisfies the objectives and guiding principles set out in Chapter 3. This should not be read as a comprehensive evaluation of all elements of the methodology; rather, we focus specifically on the suitability or otherwise of charges for large, EHV-connected generators such as Barry power station.

In our view, the methodology is particularly poorly suited to deriving charges for this type of customer. This is perhaps understandable since, as we understand it, WPD devised its LRIC methodology at a time when large distribution-connected generators in South Wales and South West England (which had all connected to the network before 2005) were not being asked to pay Use of System charges. It is only now that such generators are also being asked to pay Use of System charges that the shortcomings of the LRIC methodology for this type of customer have been fully revealed. Indeed, the fact that WPD has put forward these methodological adjustments in its modification proposal of 11 January 2010 suggests to us that WPD might itself be concerned about the ability of the methodology to generate appropriate charges for large generators.

In what follows, we first demonstrate that WPD's existing LRIC methodology would fail to generate appropriate charges for large generators when judged against Ofgem's high-level principles for network charging.

- **Concern 1 – using costs at the margin to charge total capacity.** The LRIC methodology tries to send network users a price signal that reflects the costs associated with a tiny increment in demand or generation. We argue that this is not the appropriate signal to send large, established generators that do not have the flexibility to respond to such marginal signals. We demonstrate that this failure to recognise the inherent 'lumpiness' of generation could result in sub-optimal network investment and a patently inefficient pattern of network utilisation.

- **Concern 2 – assuming that demand for use of the network grows at a steady annual rate of 1%.** We recognise that, in the absence of such an assumption, the LRIC methodology can produce extremely volatile charging patterns and even break down altogether. However, we are concerned that imposing this assumption significantly undermines the cost reflectivity of the charging methodology, particularly for large generators such as Barry power station.

- **Concern 3 – the methodology produces volatile charges even in the presence of the 1% growth rate assumption**. We are concerned that applying WPD's methodology to networks that have been sized for large generators and therefore have little spare capacity would lead to charges that are very sensitive to modest changes in subjective engineering judgments. Our theoretical concern here appears to be borne out in practice by the striking difference between the hypothetical charges calculated for Barry power station for 2009/10 and 2010/11. Such volatility could undermine the predictability of charges and make it impossible for large generators to make informed long-term siting decisions.

Collectively, these concerns make it impossible to conclude that the LRIC charges derived for large generators would be either predictable or cost reflective. This in turn makes it difficult to see how WPD could justify levying LRIC charges on these pre-2005 generators on the grounds that doing so would encourage efficient use of its network.

We also evaluate the charge capping arrangements that WPD has proposed in its modification of 11 January 2010.

- On the one hand, we acknowledge that these capping arrangements are to be welcomed in the context insofar as they hold down the extreme charges that large generators would otherwise be liable to face. This may also to some extent improve the predictability of future charges.

- However, the proposed modifications in no way mitigate our primary concern about the inability of the LRIC methodology to produce cost reflective charges for large generators. Instead of tackling the underlying causes of the methodology's failure to produce cost reflective charges, the methodology merely patches up the most severe symptoms of that failure. The capping arrangements are not, therefore, a 'solution' to the problem.

5.1 Concern 1 – using costs at the margin to charge total capacity

As explained in Chapter 4, WPD's methodology seeks to incentivise efficient network utilisation by sending each EHV customer a price signal that reflects the costs associated with that customer incrementing demand or generation by a small amount.

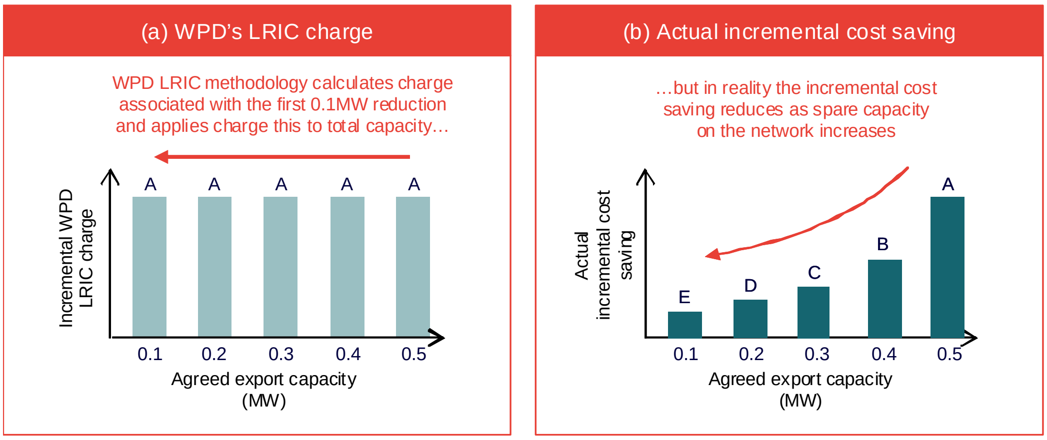
- This is, in principle at least, a comprehensible approach for the subset of network users who face such a choice: if a small demand customer is considering whether to modify its use of the local network by a small amount, then it makes sense to send that customer a price signal that reflects costs that this decision would impose on the network.

- However, this justification assumes that the relevant decision for each customer is whether or not to increment demand or generation by a tiny amount. This is clearly not a reasonable assumption for all network users. In particular, large established generators such as Barry power station would be unlikely to be in a position to respond to these marginal signals. For these fixed capacity generators, the relevant choice is not whether to increment generation by a marginal amount, but rather whether to continue exporting electricity onto the network or to cease exporting electricity altogether.

For established generators such as Barry power station, therefore, DUoS charges should send price signals that reflect the opportunity cost associated with their continued presence on the network. Unfortunately, by focusing on the costs associated with a small increment, WPD's methodology not only fails to send a relevant price signal to these generators, but actually sends a signal that severely distorts their incentives to remain on the network.

Figure 5 below sets out our concern. In this scenario, we assume that generation drives network reinforcement. We also assume that there is little spare capacity on the node, meaning that a small increment in the generator's agreed export capacity would trigger reinforcement. Because of this, the cost associated with incrementing or decrementing demand by 0.1MW (represented by *A* in Figure **5**(b)) will be relatively high.

Figure 5. Illustration of how using costs at the margin to charge total capacity can distort price signals



Source: Frontier Economics

We assume for the sake of argument that WPD's methodology accurately calculates the cost associated with a generator incrementing demand by 0.1MW (as we explain below, we do not actually believe this to be the case, but we place these concerns to one side for now). The resulting £/kVA/annum LRIC charge will therefore also be *A*.

By assumption, therefore, the methodology sends generators an accurate signal about the costs associated with modifying their agreed export capacity by 0.1MW. Now, however, suppose that one generator lacks the option of modifying its use of the network by just 0.1MW. Instead it faces the binary choice of remaining on the network at the agreed export capacity or ceasing to export electricity onto the network altogether. If this generator has an agreed export capacity of 0.5MW (for example), the principle of cost reflectivity therefore dictates that it should receive a charge that reflects the cost saving that would be associated with a 0.5MW reduction in use of the network.

Question 1: what charging signal would WPD's LRIC methodology send this generator? The LRIC methodology simply calculates the network cost saving associated with a 0.1MW change in agreed export capacity at the margin (A) and applies this charge to the generator's total export capacity. In our example, therefore, the LRIC methodology will signal to the generator that it could save $A+A+A+A+A=5A$ by reducing its agreed export capacity by 0.5MW. This is illustrated in **Figure 5(a)** above.

Question 2: what charging signal *should* the DUoS charge actually send the generator? The network cost saving associated with reducing agreed export capacity by just 0.1MW is A. It might, therefore, be tempting to conclude that the cost associated with reducing agreed export capacity by 0.5MW is just $5A$. However, this ignores the fact that the cost associated with incrementing demand for the network capacity increases sharply as spare capacity at the node approaches zero. Since there is very little spare capacity on the network in our scenario, the incremental cost saving associated with reducing agreed export capacity by 0.1MW (A) will be very high, whereas the incremental cost saving associated with reducing agreed export capacity by the next 0.1MW (B) will be less high (reflecting the fact that there is now more spare capacity on the network), and so on. The total reinforcement cost saving associated with the generator reducing its demand by 0.5MW will therefore be $A+B+C+D+E$ (see **Figure 5(b)** above). Clearly this is less than $5A$. In other words, even if the LRIC methodology were to send an accurate signal about the cost saving associated with a 0.1MW reduction in agreed export capacity, it would still overestimate the cost saving associated with a reduction of more than 0.1MW. In this respect, the LRIC methodology is therefore liable to send large network users that can only make binary decisions as to whether to remain on the network or to leave the network a severely distorted signal about the forward-looking reinforcement costs associated with their behaviour.

We illustrate this logic with a numerical example. For this example, we assume Premises 1-3 are all satisfied. In other words, (1) the LRIC methodology sends customers an accurate signal about the forward-looking costs of their incrementing or decrementing demand for use of the network by a small amount; (2) there is a large, established generator (capacity 230MW in our example) which faces a binary choice of either continuing to export 230MW onto the network or ceasing operations altogether; and (3) there is little spare capacity on this part of the network (specifically, as **Table 2** below sets out, there is only 5MW of spare capacity left).

Table 2. Inputs for stylised example

Parameter	Assumed value
Initial network capacity (MW)	240
Initial generation export capacity (MW)	235
…of which the generator in question accounts for (MW)…	230
Annual growth rate in demand for use of the network (%)	1
Standard reinforcement cost (£)	10,000
Size of increment used to calculate LRIC charge (MW)	0.1
Discount rate (%)	6.9

As Table 2 sets out, we assume for simplicity that reinforcement will be triggered if and only if total agreed export capacity reaches 240MW. We also assume that when this limit is reached, the DNO would have to reinforce the network at a cost of £10,000 (though one could choose any number here – the level of the reinforcement cost does not change the fundamental insight). Beyond this, our stylised example follows WPD's methodology in assuming that demand for use of the network grows at a steady annual rate of 1%.

Using this methodology, we can calculate the price signal that WPD's LRIC charge would send to the generator and compare this with the actual cost associated with the generator's ongoing presence on the network.

- **Calculation 1: price signal that WPD's LRIC charge would send.** Using the standard approach set out by WPD in its proposed methodology, we calculate that:
  - in the absence of the 0.1MW decrement, the £10,000 reinforcement will be required in 2.12 years. In Net Present Values (NPV) terms, the cost of this reinforcement will therefore be £8,683.35; whereas
  - by contrast, in the presence of the 0.1MW decrement, the £10,000 reinforcement will now only be required in 2.16 years. In NPV terms, the cost of this reinforcement will therefore fall slightly to £8,658.61.

The change in the NPV of the future reinforcement cost as a result of the 0.1MW decrement is therefore £8,658.61 - £8,683.35 = -£24.74. In other words, by reducing the amount of capacity it exports to the network by 0.1MW, the generator reduces the NPV of future reinforcement by £24.74. Since the generator has a capacity of 230MW, the total charge the generator faces is approximately £57,000 (£24.74 * 2,300). The LRIC methodology therefore signals to the generator that the costs associated with its ongoing presence on the network are about £57,000.

- **Calculation 2: the real cost associated with generator's ongoing presence on the network.** To derive this, we simply calculate the number of years to reinforcement (a) in the presence and (b) in the absence of the generator. We then use (a) and (b) to identify the real change in the NPV of the future reinforcement cost that results from the generator's presence on the network.

  - In the presence of the generator, the calculation is exactly as above. As things stand, the £10,000 reinforcement will be required in 2.12 years. In NPV terms, the cost of this reinforcement will therefore be £8,683.35.

  - In the absence of the generator, 230MW of additional spare capacity would become available on the network, increasing the total amount of spare capacity from 5MW to 235MW. In this hypothetical scenario, the £10,000 reinforcement would only be required 389 years into the future, given the assumed 1% annual growth rate in demand for use of the network. In NPV terms, the cost of this reinforcement will therefore fall to just £2.12.

  The actual change in the NPV the future reinforcement cost as a result of the generator ceasing to export electricity onto the network would therefore be £2.12 - £8,683.35 = -£8,683.35.

Comparing these two sets of calculations, it is clear that WPD's methodology dramatically overestimates the costs associated with the generator's continued presence on the network. The WPD methodology signals to the generator that this cost is nearly **£57,000**, whereas the real cost is less than **£9,000**.

WPD's methodology would therefore fail to send large, established generators an accurate price signal about the costs associated with their continued presence on the network. This could result in sub-optimal network investment and an inefficient pattern of network utilisation.

This insight might help explain why (in the absence of any capping arrangements), WPD's LRIC methodology produces a charge for Barry power station that is so disproportionately high. Barry's situation clearly satisfies Premises 1-3:

- WPD's LRIC methodology purportedly seeks to send Barry power station a signal about the costs associated with its incrementing its demand for network resources by a small amount.

- However, Barry power station is not in a position to vary its agreed export capacity by 0.1MW increments. Instead, the relevant choice facing the station's owners is whether to continue to export at this agreed capacity or to cease exporting electricity altogether.

- We understand that at the time of its connection, Barry was (and indeed remains) the largest generator that WPD could accommodate on that part of its South Wales network. This in turn suggests that there is very little spare capacity on the branches that serve the node at which Barry power station is located.

Given these premises are satisfied, it is clear that WPD's methodology would send Barry power station a severely distorted charging signal about the costs associated with the choices it faces:

- Because there is little spare capacity on the local network, the incremental cost saving associated with Barry power station reducing its agreed export capacity by 0.1MW will be higher than the incremental cost savings associated with further 0.1MW reductions.

- As a result, taking this initial incremental saving and multiplying it by Barry's total agreed export capacity will result in charge that dramatically overstates the actual cost associated with the power station's ongoing presence on the network.

5.2 Concern 2 – the 1% network demand growth rate assumption

In the previous section, we questioned the utility of sending signals to large generator customers that reflect the hypothetical costs associated with their behaviour on the margin. There is a more fundamental question, however, as to whether the LRIC methodology is even capable of sending large generators price signals that accurately reflect these marginal costs. It is to this question that we now turn.

As we explained in Chapter 4, WPD's LRIC methodology calculates all charges on the assumption that demand for use of the network at each node grows at a constant annual rate of 1%. This assumption is potentially contentious in two respects.

- First, it assumes a long-run annual growth rate of 1% at all nodes on WPD's network.

- Secondly, it assumes that this growth is steady and smooth.

These may be reasonable assumptions for certain types of customer at certain nodes. However, we believe that these assumptions are both quite clearly unrealistic for nodes that are dominated by large, established generators. We set out our thinking behind these concerns in more detail below.

We are concerned that this unrealistic 1% growth assumption could severely undermine the ability of WPD's LRIC methodology to send large generators charging signals that accurately reflect the forward-looking costs associated with a small increment in generation. We recognise that, in the absence of such an assumption, WPD's methodology would simply break down when tasked with deriving charges for those parts of the network that are not forecast to experience demand or generation growth. However, by arbitrarily assuming that the growth rate is 1% in these cases, the resulting charge will fail to send network users a signal that better reflects the costs associated with locating on different parts of the network than the current approach.

We understand that WPD's decision to introduce a 1% growth rate assumption at all nodes may have been motivated by two concerns:

- First, WPD may have wished to enhance the **simplicity** and **transparency** of the methodology. Forecasting specific growth rates at each node involves a lot of uncertainty and may have forced WPD to make subjective judgments about the prospects for growth on different parts of its network.

- Secondly, WPD may have been concerned about the ability of the LRIC methodology to produce **highly volatile charges** at low assumed growth rates. In its October 2008 decision document on the electricity distribution structure of charges prospect, Ofgem acknowledged concerns that, in the absence of the 1% growth assumption, the LRIC approach would produce "excessive charges under conditions of high utilisation and low growth rates" [16]. Indeed, the simple calculus of the WPD model breaks down altogether as the assumed growth rate tends to zero. We illustrate this volatility concern in the Box 1 below.

16 '*Decision Document: Delivering the electricity distribution structure of charges project*', Ofgem, 1 October 2008 (Ref 135/08), Section 2.55.

Box 1 – How the LRIC model can break down in the absence of a 1% growth assumption

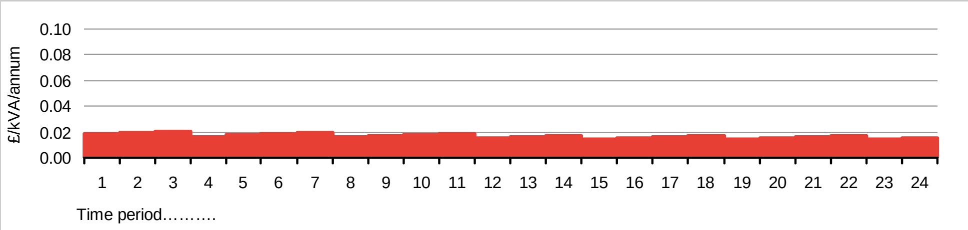
Consider a node with the characteristics set out in Table 3 below. To keep the exposition simple, we assume that the node is served by a single branch and that the security factor is 1.

Table 3. Parameter assumptions for worked example

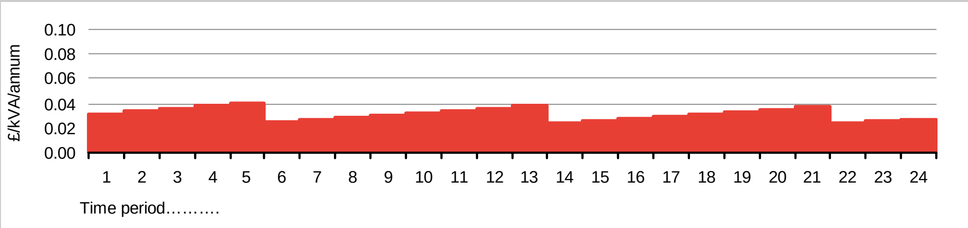
Input	Value
Initial asset capacity (MW)	240
Initial base power flow (MW)	235
Size of power flow increment (MW)	0.1
Size of standard reinforcement increment (MW)	10
Reinforcement cost (£)	10,000
Discount rate (%)	6.9
Annuity period (years)	40

While inputs set out in the table above purely hypothetical, we understand that they are not atypical for a node on a GB distribution network. However, as the forecast demand growth rate on this node tends to zero, the dynamic pattern of charges becomes increasingly volatile, as Figure 6 below illustrates:

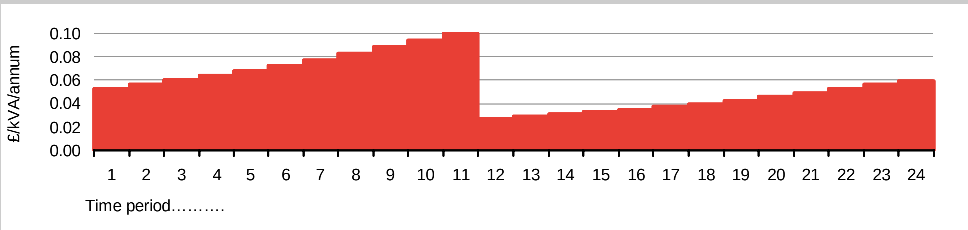
Figure 6. Illustration of how the LRIC charge in this worked example would evolve dynamically under different demand growth rate scenarios



Scenario (a)
1% load flow growth rate



Scenario (b)
0.5% load flow growth rate



Scenario (c)
0.2% load flow growth rate

Source: Frontier Economics

Figure 6 sets out how charges at the hypothesised node would develop over time under three different growth rate scenarios (1%, 0.5% and 0.2% respectively).

- Note that in each scenario, we assume that WPD correctly forecasts the growth rate: in Scenario (b), for example, WPD forecasts 0.5% annual growth in demand for network resources and this 0.5% forecast turns out to be accurate.

- Each chart shows how the £/kVA/annum LRIC charge would develop over a 24 year period (so, looking at the bottom chart for example, the LRIC charge rises from just under £0.06/kVA/annum in year 1 to £0.10/kVA/annum in year 11). In all three scenarios, the £/kVA/annum charges follow a 'saw tooth' pattern: LRIC charges gradually rise as demand for use of the network increases and spare capacity at the node tends to zero, but then fall abruptly when reinforcement is triggered and an additional 10MW of spare capacity is added to the network. Since demand for use of the network continues to increase as a steady rate (by assumption), the cycle then repeats itself.

The three scenarios illustrated in **Figure 6** indicate that the amplitude of this saw tooth pattern increases as the forecast growth rate gets closer to zero.

- In **Scenario (a)**, where demand for use of the network is forecast to grow at a constant annual rate of 1%, reinforcement occurs every three or four years; charges do not drop dramatically following each reinforcement.

- In **Scenario (b)**, where demand for use of the network is forecast to grow at a constant annual rate of 0.5%, reinforcement occurs every seven-to-eight years and charges lose about a third of their value following reinforcement.

- In **Scenario (c)**, where demand for use of the network is forecast to grow at a constant annual rate of just 0.2%, the frequency of network reinforcement falls yet further. In this stylised example, charges peak in year 11 before losing nearly three quarters of their value in year 12, following network reinforcement.

This analysis suggests that the LRIC methodology is likely to produce an increasingly extreme pattern of charges as the assumed rate of growth in demand

In our view, these concerns about the LRIC methodology in the absence of the 1% growth assumption are well-founded. To this end, imposing the 1% growth assumption not only enhances the transparency and simplicity of the methodology, but also prevents the methodology from simply breaking down in situations where the real growth rate is near zero.

However, in solving one set of problems, the 1% growth assumption inadvertently creates problems of its own. In particular, fixing the growth rate at 1% across all nodes significantly undermines the ability of the LRIC methodology to send large generators users cost reflective price signals. We have two concerns here:

- First, that assuming a 1% growth rate can produce counterintuitive charges; and

- Second, that, especially for generation, a 1% growth rate is unrealistic and therefore distorts the cost reflectivity of the price signal.

We discuss each in turn.

5.2.2 Assuming steady 1% growth can produce a counterintuitive and arbitrary pattern of charges

We illustrate this point with a worked example. Suppose that two nodes, A and B, have the following characteristics:

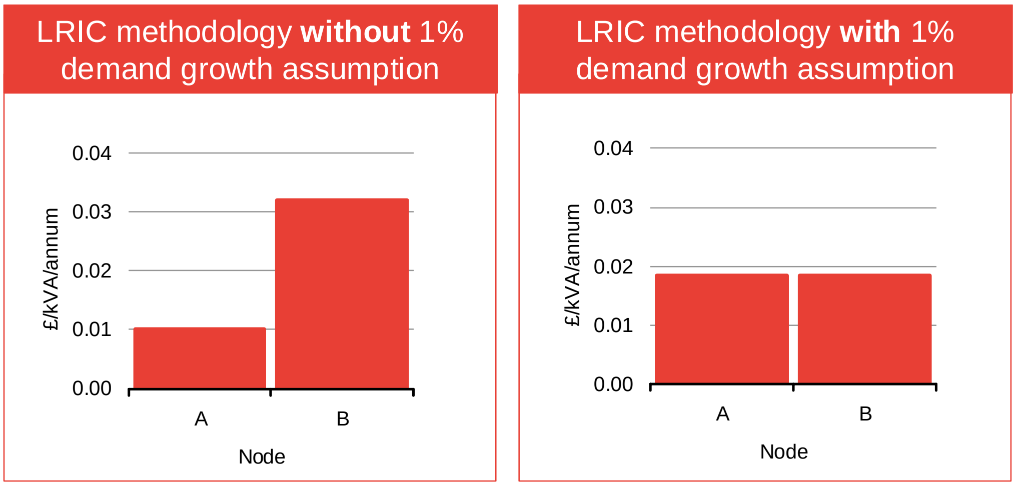
Table 4. Inputs for worked example 5

Input	Node A	Node B
Initial asset capacity (MW)	240	240
Initial base power flow (MW)	235	235
Actual growth rate in demand for network use	**2%**	**0.5%**
Size of demand increment (MW)	0.1	0.1
Size of reinforcement increment (MW)	10	10
Reinforcement cost (£)	10,000	10,000
Discount rate	6.9%	6.9%
Annuity period (years)	40	40

Source: Frontier Economics

As Table 4 sets out, the two nodes are identical in almost all respects: both nodes are dominated by generation and have little spare capacity. Similarly, both nodes will incur the same reinforcement cost once capacity is reached. These nodes do differ, however, with respect to the assumed demand growth rate: demand for network resources on Node A is expected to grow at a rate of 2% a year, whereas demand for network resources on Node B is expected to grow at just 0.5% a year. Using these forecast growth rates, the LRIC methodology would derive charges of £0.01/kVA/annum for Node A and just over £0.03/kVA/annum for Node B. However, imposing the 1% demand growth rate assumption on both nodes has the effect of nearly doubling the charge for Node A and nearly halving the charge for Node B as set out in Figure 7 below.

Figure 7. Effect of the 1% demand growth rate assumption on charges for nodes A and B



Source: Frontier Economics

Figure 7 illustrates two important points:

- First, simply assuming that demand for use of the network grows at 1% irrespective of whether the evidence suggests otherwise introduces an element of arbitrariness into the methodology that is capable of having a significant effect on the charge rate. In our opinion this is an undesirable feature of the methodology: it is hard to justify an approach that consciously replaces accurate inputs with inaccurate inputs, and even harder to justify an approach where such actions are potentially capable of having a marked impact on the final charges levied.

- Secondly, imposing a 1% growth rate assumption prevents the methodology from sending network users accurate signals about the relative costs associated with connecting to the network at different locations.

  - The forward-looking costs associated with reinforcing the network at Node A where demand for use of the network is predisposed to grow rapidly are likely to differ from the forward-looking costs associated with reinforcing a network at Node B where demand for use of the network is predisposed to grow only slowly.

  - However, by assuming a fixed 1% demand growth across all networks, the methodology deliberately blinds itself to these forward-looking cost differences.

  As we noted in Section 3.1, Ofgem has emphasised that charging methodologies should seek to send network users forward looking and cost reflective signals that help them make informed decisions about where to locate in the network. As we have shown above, however, the 1% growth assumption is capable of distorting these forward looking locational signals.

5.2.3 Assuming steady 1% growth is unrealistic at nodes where large generators dominate

It is hard to support the proposition that deliberately inserting a false assumption into the methodology will help generate charges that are more cost reflective. The key question, therefore, is whether the 1% growth rate assumption is a reasonable one for the majority of nodes. Unfortunately the evidence suggests that the assumption is often far from reasonable in two respects.

- First, the **assumption of a 1% long run rate of growth** seems unrealistic for those nodes where generation growth drives reinforcement. Barry power station is a case in point here:
  - from discussions with WPD, we understand that Barry is currently the only network user at the Sully 132kV node and has been the only user since it connected to the network in 1997.
  - Barry's agreed export capacity has remained fixed throughout the 13 years since it connected.

  Given that there has been no change in agreed export capacity at Sully 132kV over the last decade, it is not clear what justification there is for assuming that it will grow at an annual rate of 1% from 2010 onwards.

- Secondly, the **assumption of smooth year-on-year growth in demand for use of the network** is equally unrealistic for nodes where generation drives network reinforcement. Where changes in agreed export capacity do occur for these customers, they likely to occur in sudden, discrete jumps, as new generators connect to the network or existing generators modify their agreed export capacity. One would only expect to see smooth year-on-year growth for nodes that serve numerous small network users.[17]

[17] It is worth noting that other proposed DUoS charging methodologies explicitly recognise this inherent 'lumpiness' in EHV generation. The Forward Cost Pricing (FCP) methodology proposed by the 'G3' group of DNOs is one such methodology. It calculates EHV generation charges by estimating the reinforcement cost that would be incurred by a discrete 'lump' of generation connecting to the network and then assessing the probability of this lump connecting over a ten-year horizon.

5.3 Concern 3 - the LRIC methodology produces highly volatile charges

Our concern here is based on the empirical observation of the charges that WPD has derived for Barry power station.

- In its modification proposal of 26 August 2009,[18] WPD submitted a "proposed charge" of **£4,232,595** for Sully 132kV (the node at which Barry power station is located) for 2009/10.[19]
- However in its modification proposal of 11 January 2010,[20] WPD set out an equivalent charge of **£2,178,486** for Sully 132kV for 2010/11 (this charge excludes the capping arrangements or other adjustments for pre-2005 generators that WPD now intends to impose – we consider the implications of these proposed adjustments later in the chapter).
- This implies a year-on-year fall in the charge for Barry of **nearly 50%, or £2.1 million**.

Even with the 1% growth assumption in place, therefore, WPD's LRIC methodology seems capable of generating a significant degree of volatility in year-on-year charges. It is possible, of course, that this extraordinary year-on-year change was driven by an equally extraordinary shift in the underlying demand or supply conditions at that node. For example, a large demand customer might have located at the same node as the power station, thereby significantly reducing the amount of electricity being exported onto the distribution network and freeing up spare capacity. However, we have discussed this possibility with WPD and understand that no dramatic developments of this nature have occurred. Instead, the dramatic change in Barry power station's charge appears to have been driven primarily by a change in the line rating of one of the branches serving the station, which meant that WPD increased its estimate of the amount of spare capacity on the network. It is, in our view, a source of some concern that an apparently subjective engineering judgment could exert such a dramatic effect on the charge that a generator faces: indeed, this insight

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18 See WPD, "Amendment of Use of System Charging Methodology to revoke the LV/HV DRM Methodology from the Implementation Date of the CDCM ", 26 August 2009

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/WPD%20UoS%20Modification%20Report%20013_2009.pdf

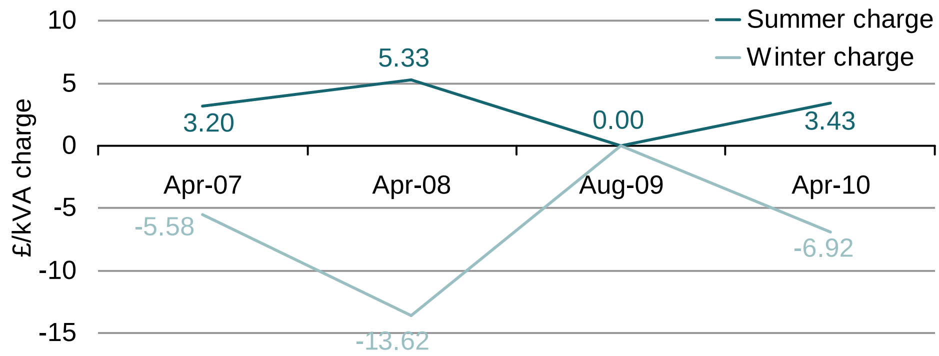
19 Before scaling to allow WPD to recover its allowed revenue. However, since WPD is now proposing not to scale generator charges, we can treat this as the de facto proposed final charge.

20 See WPD, "Amendment of Use of System Charging Methodology to revoke the LV/HV DRM Methodology from the Implementation Date of the CDCM ", 11 January 2010

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/wpdmodificationrequest%20016.pdf would appear to undermine not only the predictability of final charges but also the transparency of the charging framework.

Our concerns in this regard are heightened by an examination of the historic profile of tariffs at the Sully 132 kV node – which is the node at which Barry is connected. These tariffs have been reported by WPD even though Barry was exempted from paying the charge under the terms of its connection agreement. The tariff profile is represented in Figure 8 below.

Figure 8. Recent DUoS charges proposed for Sully 132kV



Source: Western Power Distribution

As Figure 8 demonstrates, the tariffs derived through the methodology have been highly volatile since its introduction in 2007. For example, the summer charge £/kVA tariff increased by 67% between 2007 and 2008. The tariff then fell from 5.33 £/kVA to zero[21] in 2009. Similar volatility is evident for the winter £/kVA charge.

This volatility seems to us to be contrary to the ambition that charges should be predictable. Indeed, it is hard to conceive of how a user could make long term siting or retirement decisions in an efficient manner given this volatility.

5.4 Capping arrangements

The manifest failure of the methodology to derive suitable tariffs for the reasons that we have cited above means that WPD have, quite understandably, made some changes to the charging methodology. In particular, as we explained in the previous chapter, WPD are now proposing to introduce a **"capping arrangement"** to restrict EHV customers' branch charges to their asset value.

21 The data as presented in WPD's 2009 methodology reports that the tariff at the Sully 132 kV node would have been zero, although we believe that this might be an error.

Specifically, WPD propose to cap each relevant branch's LRIC charge if it is found to exceed an annuity of the asset value for that branch.

We understand that WPD may have been motivated to introduce these capping arrangements by a concern that the 'unconstrained' methodology was producing charges for some customers that were demonstrably too high to be cost reflective. In this respect the proposed cap acts as a basic sense check and, as such, should be welcomed.

While the proposal to put a cap in place therefore constitutes a step forward, it is also a worrying development in two respects.

- First, in deciding to introduce these capping arrangements, WPD itself appears to be acknowledging that its LRIC methodology fails to generate cost reflective charges for all network users. It also appears to confirm that the uncapped LRIC methodology performs particularly poorly in this regard with respect to large generators.
    - Imposing the cap had the effect of forcing down Barry power station's proposed charge by more than 50% (from £2.2 million to £0.8 million).
    - From subsequent discussions with WPD, we understand that no fewer than three of the branch assets serving Sully ended up having their charges actively capped in this manner.
- Secondly, it is important to realise that the proposed cap is nothing more than an act of damage limitation. Instead of tackling the underlying causes of the methodology's failure to produce cost reflective charges, the methodology merely patches up the most severe symptoms of that failure. In no way is it a 'solution' to the problem: even where the cap does bite, the resulting charges cannot claim to send the correct signal to network users about the costs associated with their utilisation of the network.

We would, therefore, argue the proposed capping arrangements are a step forward insofar as they would mitigate the extreme volatility of charges. However, imposing the cap in no way mitigates our fundamental concern: WPD's LRIC methodology would still fail to produce charging signals for large generators that are cost reflective in any meaningful sense.

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