Promoting choice and value for all customers

To distributors, suppliers, generators, customers and other interested parties

Our reference 38/09
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9 April 2009

Dear colleague,

This letter contains two consultations that cover the same subject area, namely boundary charges for IDNOs:

(1) Consultation on UoS 012 proposal from Western Power Distribution (South Wales) plc and Western Power Distribution (South West) plc to modify their Use of System charges for Independent Distribution Network Operators (IDNOs); and

(2) IDNO/DNO working group consultation on IDNO boundary charging methodologies to facilitate the development of an enduring common IDNO charging methodology to be implemented by April 2010.

Before dealing with the specific consultations the letter details some background material relevant to both consultations.

Background

IDNO networks typically provide the distribution network for new build housing or commercial developments sometimes referred to as the "last mile". IDNOs compete with the incumbent DNO (and DNOs operating out of area) to adopt these new networks from the developer. Once adopted, the IDNO operate and maintain the new network, and invoice suppliers in the same manner as a DNO would do. Once a licence is granted the IDNO can compete to operate networks across all DNO areas[1].

In order to serve their customers IDNOs connect to a DNO's network. As a result, IDNOs pay the DNO UoS charges which should broadly reflect the shared costs the IDNOs impose on the DNO's network, measured and collected at the IDNO/DNO boundary. The IDNO is subject to a relative price control[2] (RPC) by which their charges to domestic customers are effectively capped to the level which the host DNO charges. An IDNO's gross margin is therefore defined by the difference between the boundary charge levied by the DNO and sum of end-customer charges levied by the IDNO[3]. In addition to ensuring (as far as reasonably practicable) cost reflectivity in their methodologies, DNOs are also required to ensure their methodologies do not restrict or distort competition in distribution of electricity.

[1] This is with the exception of EDF (IDNO) who are restricted to operating within EDF's LPN DSA.
[2] This is outlined in amended condition BA2 of IDNO licences.
[3] The end charges levied by the IDNO are subject to a relative price control under amended condition BA 2. This states that for domestic customers, the IDNO can charge no more than the host DNO.

A further aspect that DNOs have to take into consideration in setting boundary charges is the Competition Act 1998. In this context it should be noted that Ofgem launched a Competition Act investigation into ENW in January 2009 following a complaint regarding alleged margin squeeze by ENW in respect of an IDNO. The complaint raises certain issues and concerns which are common across all DNOs

At present all DNOs, with the exception of WPD, charge IDNOs as they would a normal commercial customer. Ofgem have long been encouraging DNOs to introduce new specific IDNO tariffs which more accurately reflect the costs which IDNOs impose on DNOs' networks and which are able to help better facilitate competition[4]. In December 2007, WPD had an IDNO specific charging methodology 'not vetoed' by the Authority[5] on the basis that they better achieved the relevant objectives. Consequently, since April 2008, WPD have charged IDNOs on the basis of a domestic restricted customer[6] discounted for the costs which WPD estimate they avoid when the IDNO rather than WPD distributes units from the DNO network to the end customer.

In July 2008, Ofgem agreed to facilitate a forum where IDNOs and DNOs could meet without prejudice and discuss options for revised IDNO charging methodologies. The working group subsequently worked towards the implementation of a common interim IDNO charging methodology in April 2009 which would be developed to form an enduring IDNO charging methodology for April 2010. Unfortunately the industry working group has not achieved the April 2009 deadline. Our intention is to propose a new licence condition that will require all DNOs to implement the enduring methodology as part of the overall common charging methodology for all HV & LV customers by April 2010.

Whilst the working group is now looking towards the solution for April 2010, we would like to express our disappointment at the failure of DNOs to implement an interim solution for April 2009.

Given the failure to agree a common interim solution, we expect individual DNOs to submit interim modification proposals as soon as possible. Ofgem has clearly stated that charging IDNOs on the same basis as a commercial customer is not appropriate. We take this issue very seriously and we wish to resolve this issue as speedily as practicable. We are undertaking a formal Competition Act investigation against one DNO and we would give due consideration to any further formal complaints that we may receive.

Consultation on UoS 012 proposal from Western Power Distribution (South Wales) plc and Western Power Distribution (South West) plc to modify their Use of System charges for Independent Distribution Network Operators (IDNOs)

Distribution Network Operators (DNOs) have licence obligations[7] to have in place a statement of use of system (UoS) charging methodology, a statement of UoS charges and a statement of connection charging methodology and charges. The statement of UoS charging methodology outlines the method by which distribution UoS charges are calculated.

DNOs are required to keep their statement of UoS charging methodology under review and to bring forward proposals to modify the methodology that they consider better achieve the relevant objectives[8].

[4] Please see references to our past decision letters on IDNO charging which can be found on the modifications page of our website http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx
[5] In this letter the term Authority and Ofgem are used interchangeably.
[6] A restricted customer is an E7 customer who pays a day unit charge and a night unit charge.
[7] Standard Licence Conditions (SLC) 13.
[8] The relevant objectives for both the connection and use of system charging methodologies, as contained in paragraph 3 of SLC 13 of the distribution license respectively are:

- that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Act and by the licence;

Before making a modification to a statement of UoS charging methodology a DNO must submit to the Gas and Electricity Markets Authority (the "Authority")[9] a proposal to modify its methodology stating how the proposal better achieves the relevant objectives. The DNO then makes the modification unless within 28 days the Authority either directs the DNO not to make the modification or notifies the DNO that it intends to consult and then within three months directs the DNO not to make the modification.

Western Power Distribution (South Wales) plc and Western Power Distribution (South West) ("WPD") plc submitted a proposal on 28 February 2009 to modify their respective statements of UoS charging methodologies in respect of how they charge IDNO[10] customers connected to their networks[11]. On 27 March 2009, the Authority notified WPD in writing of its intention of consult upon their revised IDNO charging proposals[12].

WPD submission

The charging methodology modification proposal from WPD reflects the fact that the DNOs within the working group have not been able to agree a common interim IDNO charging methodology. Annex 1 to this letter provides a detailed description of WPD's proposed methodology, highlights the main issues and asks respondents for their views on whether WPD's proposals are more cost reflective and better achieve the relevant objective not to restrict, prevent or distort competition.

Views sought

The proposal from WPD represents a substantial change to their current methodology. The Authority has taken the decision to consult on the proposed modifications to further evaluate the extent to which the changes they represent address the current issues and do not raise further issues in relation to the way(s) in which the modification proposals better achieves the relevant objectives. Specifically, we are looking for views on;

- The extent to which the proposals are more cost reflective than the WPD's current methodology[13];
- Whether WPD demonstrate that its proposal facilitates competition in generation and supply and do not restrict, distort or prevent competition in transmission and distribution[14];
- Whether we have correctly captured the main issues raised by WPD's proposal.
- The specific questions related to WPD's proposal in Annex 1.

- that compliance with the use of system charging methodology facilitates competition in the generation and supply of electricity, and does not restrict, distort, or prevent competition in the transmission or distribution of electricity;
- that compliance with the use of system charging methodology 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
- that, as far as is consistent with the sub-paragraphs above, the use of system charging methodology, as far as is reasonably practicable, properly takes account of developments in the licensee's distribution business.

[9] Ofgem is the office of the Authority. The terms 'Ofgem' and the 'Authority' are used interchangeably in this letter.
[10] This also applies to DNOs operating of area within WPD's DSAs.
[11] Modification report - Use of System Charging Methodologies for IDNO Networks UoS 012, which can be found on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx.
[12] This letter can be found on our website at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx
[13] Standard condition 13(3(c)) of the electricity distribution licence.
[14] Standard condition 13(3(b)) of the electricity distribution licence.

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IDNO/DNO working group consultation on IDNO boundary charging methodologies to facilitate the development of an enduring common IDNO charging methodology to be implemented by April 2010

On 20 March 2009, Ofgem published its decision document on 'Next steps in delivering the electricity distribution structure of charges project'[15]. This proposes to place an obligation on DNOs to have in place a common, enduring IDNO charging methodology, developed by DNOs working with IDNOs, by April 2010. We have stated to the IDNO/DNO working group that their attention should now focus on the development of the enduring solution which will form part of the common methodology implemented in April 2010.

Consequently, we feel that there is substantial merit in producing a separate consultation to gather views on the most appropriate common IDNO charging methodology for 2010 onwards. In addition to WPD, CE have also developed their own proposals whilst the remaining DNOs[16] are developing proposals on IDNO charging centred around a methodology developed in close consultation with Reckon LLP (described in this document as the Reckon methodology). Annex 2 contains a description of the CE approach, a description of the Reckon methodology and a comparison of the different approaches WPD, CE and Reckon have taken and ask for views on which aspects of each method are the most cost reflective and best able to facilitate competition.

We believe that this consultation will help the working group to progress towards a common IDNO charging methodology for April 2010. The Authority would like to stress that this consultation is completely separate from the formal WPD consultation. Given that the WPD proposal is one of a number of options the working group will have to consider for the enduring proposal, we believe that it is sensible to place comparative consultation in the same document as the WPD consultation.

Views sought

In addition to comments on WPD's proposal, we welcome separate views on the specific questions outlined in Annex 2 where the various IDNO charging approaches are compared.

Responding to this consultation letter

Views are invited on these points from any interested parties, including IDNOs, DNOs suppliers, customers and their representatives.

Views are invited by **21 May 2009**. Where possible, responses should be sent electronically to Mark Askew, e-mail distributionpolicy@ofgem.gov.uk.

Our decision on WPD's modification proposal (and any other UoS charging modifications we receive dealing with IDNO boundary charges) will be taken on the basis of whether they better meet the relevant objectives and our wider statutory duties.

The process associated with modifications to the charging methodologies is detailed within the electricity distribution licence (SLC 13). As the Authority's decision is time bound, please ensure that your comments are received by the date indicated so that they can be fully considered. It may not be possible to consider responses on the WPD modification proposal that have been received after this date, however, as the Authority needs to make a decision on this matter on or before 27 June.

All responses will be held electronically by Ofgem. They will normally be published on our website unless they are clearly marked confidential. Consultees should put confidential material in appendices to their responses where possible. We prefer to receive responses

[15] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Next%20steps%20SoC%20decision%20doc.pdf.
[16] SP, CN, SSE, EDF, ENW & CE.

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electronically so that they can easily be placed on the website. **We would ask that respondents clearly distinguish between their views on WPD's modification proposal and their responses to the comparative working group consultation.**

Copies of this document are available on our website under the distribution charging modifications area of work[17]. If you have any questions concerning either consultation document please contact Mark Askew at mark.askew@ofgem.gov.uk or on 0207 901 7022.

Yours faithfully,

Rachel Fletcher
Director, Distribution

[17] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx.

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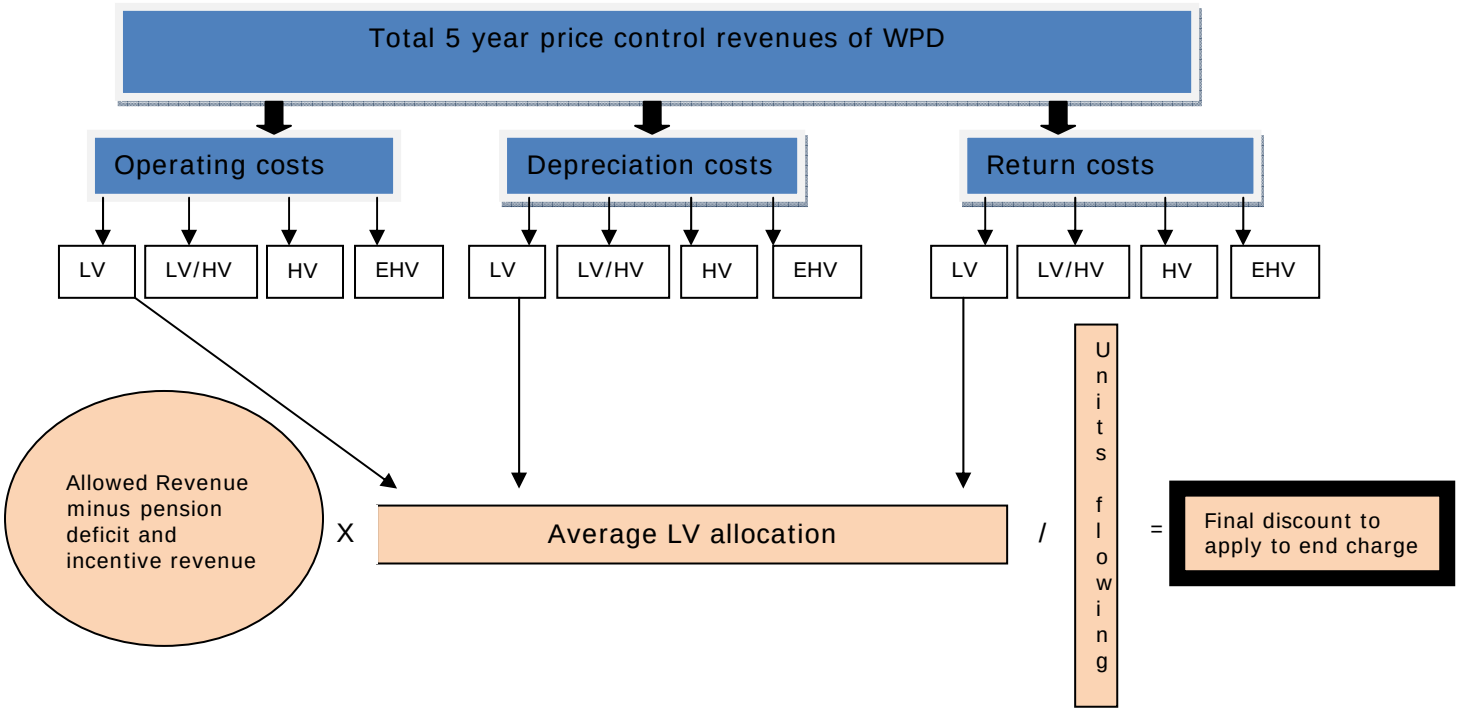
Summary of WPD's approach

1.1. At a high level, WPD propose to make a fundamental shift in approach moving from a methodology which bases IDNO charges on incremental costs at each network level (a bottom up approach), to a top down approach which looks at the allocation of total business costs between network levels.

1.2. Figure 1.1 below demonstrates (at a high level) the 'top down' approach WPD propose to use. Their top down approach is essentially an Average Accounting Cost (AAC) type approach (see Annex 2). This AAC approach was advocated in the IDNO/DNO working group as being a more appropriate basis on which to charge downstream competitors.

Figure 1.1 – high level summary of WPD's allocation of costs to the LV network



WPD have used a combination of their price control settlement and costs in the Revenue Reporting Packs (RRP) and FBPQ (forecast business plan questionnaire) data to allocate costs across four network levels[18]. They use the price control settlement in DPCR 4 to allocate allowed revenues between depreciation, return on capital and operating costs. They then use RRP data to allocate operating costs and FBPQ data to allocate depreciation and return between network levels.

1.3. Table 1.1 below uses the data from the DPCR4 price control settlement in respect of WPD South West[19] to analyse the allowed revenues between operating costs, depreciation and return. This shows that the allowed revenues over the five years of the price control are divided 35% as operating costs, 33% as depreciation and 32% as return.

[18] In this instance network levels refer to EHV, HV, HV/LV & LV.
[19] Sourced from Electricity distribution price control review: statutory consultation on the licence modifications – February 2005

Table 1.1- Price control settlement for WPD South West

£m, 2002/03 prices	2005/6	2006/7	2007/8	2008/9	2009/10	Total
Allowed Revenues	175.6	177.8	180.3	182.3	184.6	900.6
Opex	59.3	61.4	62.2	61.8	61.5	
Information Quality Incentive	1.7	1.7	1.7	1.7	1.7	
DPCR3	1.6					
Total Opex	62.6	63.1	63.9	63.5	63.2	316.3
Capital Elements						
Depreciation	50.3	55.5	59.1	62.7	66.3	293.9
Tax Allowances	15.8	16.4	17.1	17.8	18.6	
Capital Incentive	4.5	4.1	2.8	1.8	0.9	
Sliding scale	1.4	1.5	1.5	1.5	1.5	
Return	41.0	37.2	35.9	35.0	34.1	
Total Capital	113.0	114.7	116.4	118.8	121.4	
Total capital ex Depreciation	62.7	59.2	57.3	56.1	55.1	290.4
Allocation of Allowed revenue to:-						
Opex						35.1%
Depreciation						32.6%
Return						32.2%

1.4. WPD then allocate each of these cost categories to the four network levels they have identified using certain cost drivers as a proxy.

1.5. For operating costs WPD employ a three stage process:

- Firstly, some costs (known as direct costs in RRP data), are directly attributed to the network levels in the RRP. In WPD South West, 27% of costs and in WPD South Wales 33% of operating costs are in this category. Any unattributed direct costs are allocated to network levels pro-rata to the direct costs that are directly attributed.

- Secondly, most of the indirect costs are allocated to network levels in proportion to the modern equivalent asset value (MEAV) of WPD's network (including services). In WPD South West 39% of costs and in WPD South Wales 28% of operating costs are in this category.

- Finally, any costs without a specific cost allocation driver (mainly IT & Telecoms, property management and network rates) are allocated in proportion to (i.e. pro rata) the directly attributed and allocated indirect costs. In WPD South West 33% and in WPD South Wales 37% of costs are in this category.

1.6. The net result of this process is summarised in the table below.

Table 1.2 – allocation of operating costs to network levels

	EHV	HV	HV/LV	LV
WPD West	27%	21%	8%	44%
WPD Wales	31%	24%	7%	38%

1.7. For depreciation and rate of return, the cost driver which WPD has chosen is net capex additions to their network, as reported in the August 2008 FBPQ (forward business plan questionnaire) returns. This is effectively all capex invested in the network and has

been used in the absence of any data to directly determine how much of the existing net asset base relates to different voltage levels. The net refers to the exclusion of customer contributions as these contributed assets have been constructed by a developer and which the DNO then adopts free of charge.

1.8. The table below summarises the results of the capital allocation which represents 65% of allowed revenues.

Table 1.3 – Allocation of capital costs

	Allocation of capital costs			
	EHV	**HV**	**HV/LV**	**LV**
WPD West	37%	21%	12%	30%
WPD Wales	40%	30%	12%	18%

1.9. The table below shows how WPD use these allocations with the analysis of the price control data to establish the level of allowed revenues to be allocated to each network level by using the data from tables *1.1, 1.2 & 1.3*

Table 1.4 – Percentage allocation of allowed revenues to network levels

	Price control totals	**EHV**	**HV**	**HV/LV**	**LV**
Operating costs	316	84.0*	66.8	25.4	85.7
Depreciation	294	107.5	63.1	36.5	86.8
Return	290	106.1	62.3	36.0	140.2
Total	901	297.7	192.1	97.8	312.8
% of allowed revenues		33%	21%	11%	35%

* As an example, the EHV operating cost allocation is computed by taking the operating cost allocation of £316m and multiplying by the EHV operating costs allocation % of 27% from table 1.2.

1.10. The specific outputs of the allocation are adjusted to take account of the units flowing through each network level. This is done in order to convert costs allocated to each network level into tariffs comparable to the end charge. The final allocation once adjusted for units flowing is then used as a discount to apply to the "All The Way" customer charge. For example, if the final allocation across network levels resulted in 30% of costs being allocated to LV then the starting point for a domestic LV IDNO charge would be a 30% reduction to all components of the end customer domestic restricted tariff.

1.11. Having established the appropriate % allocation to each network level, WPD then apply these percentages to the ex post annual allowed revenues after two adjustments. WPD deduct from allowed revenues the amount resulting from pension deficit costs and incentive payments. These amounts are recovered on a p/kWh basis from all customers including boundary charges. The table below illustrates this for the LV network for WPD South West.

1.12. The starting point for the IDNO discount (immediately after the transformer) would be £69m or 0.64 p/kWh[20]. This is reduced depending on the distance of the point of connection (POC) from the transformer.

[20] This is calculated by taking the £69m and dividing by the total units flowing through WPD West's LV network.

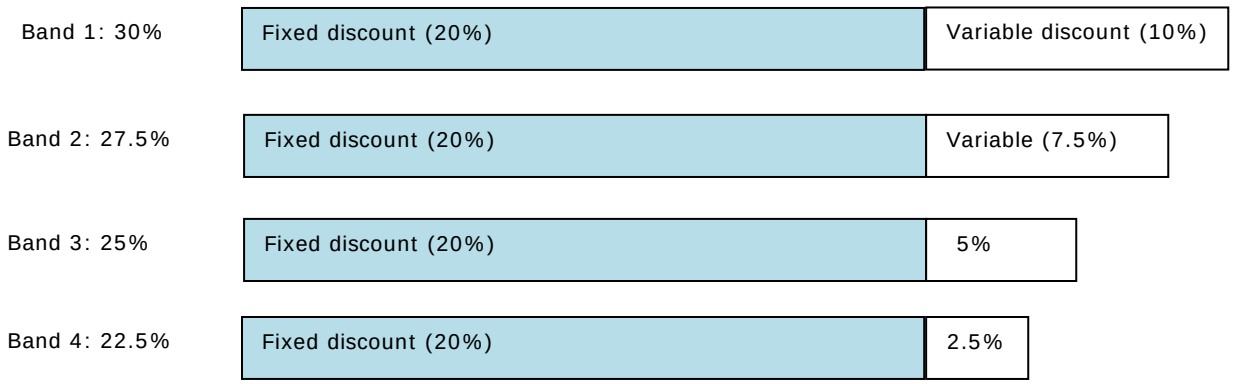
Table 1.5 – Allocation of LV costs

	£m
Within year Allowed revenues	213.9
Less: Pensions deficit allowance	(7.9)
Less Incentive payments	(7.5)
Allowed revenues to share	198.5
LV % (from table 1.4)	35%
LV allocated portion	69.0

1.13. WPD have retained their existing policy of distance related tariffs for LV IDNOs. In their current methodology, they vary the discount on the incremental costs produced in the DRM (distribution reinforcement model) according to how far away the point of connection is from the LV substation. In their current approach, WPD also cap scaling (a proxy for indirect costs) to the HV level. In order to retain this policy in their proposed approach they divide the discount provided into a fixed and variable element based on the proportion of indirect and direct operating costs. The indirect cost part of the discount is fixed while the direct cost part is varied by distance.

1.14. The fixed : variable aspect of the discount is shown by figure 1.2 below using illustrative discount figures[21]. In this example WPD would have calculated that 67% of the costs within RRP data were indirect and 33% direct and so a connection to the band closest to the LV substation would receive a 30% discount comprised of a 20% fixed discount and a 10% variable discount.

Figure 1.2 – illustrative example of WPD banding methodology



1.15. WPD have used this methodology to produce specific IDNO tariffs for domestic and non domestic sites at LV and HV. For non domestic LV sites, they take the discount calculated according to the method above and apply it to all components of the LV HH charge, both unit (p/kWh) and capacity (p/kVA).

1.16. For HV sites, there is no banding. WPD state that the HV network is configured differently so that flows are not so unidirectional and costs do not vary materially with distance. For predominantly domestic IDNO HV connected networks the IDNO discount on the 'all the way' charge is simply calculated by discounting the end consumer domestic restricted tariff by the percentage of costs allocated to both the HV/LV and LV network

[21] These discount figures are very close to the actual discounts which WPD calculate – 31% for WPD Wales and 38% for WPD West.

levels. The HV, predominantly non domestic, IDNO boundary charge is calculated by taking the existing end customer HV tariff and discounting it by the % of costs allocated to the HV part of the network. However, this discount is then reduced by the proportion of the network which WPD estimate they provide to private networks in their area.[22]

Main issues

Top down Vs Incremental

1.17. As described above, WPD's proposal represents a move from an incremental avoided cost model using the DRM to a top down average accounting cost (AAC) model. Annex 2 of this letter contains a detailed comparison of the two methods. Respondents should refer to this when considering the merits of WPD's proposal and the questions we pose below.

1.18. IDNOs have argued that an avoided cost approach based on the incremental costs of the DRM does not provide them with sufficient margin to cover the fixed overheads associated with operating a distribution business. They also indicate that the DRM does not include the average costs of operating certain voltage levels and that consequently, it is not fit for purpose in calculating tariffs for downstream competitors.[23]

1.19. As part of the work towards a common LV and HV methodology for end users, Ofgem has continued to work with DNOs in developing the DRM as it believes that the marginal cost signals it provides are the most cost reflective and sends the correct economic signals to end customers.

1.20. We would ask respondents to consider;

Whether WPD's proposal to use a top down AAC avoided cost approach is more cost reflective than their current DRM avoided cost approach?

Whether WPD's proposal to use a top down AAC avoided cost approach does not restrict competition in distribution compared to their current methodology?

Whether it is appropriate and cost reflective to make a distinction between the methods used to calculate charges to IDNOs and end customers?

Whether it is appropriate to use the AAC method to provide a discount on the end customer charge derived from the incremental DRM?

Allocation of allowed revenue as basis for top down cost allocation

1.21. As highlighted in the summary of their proposal (Table 1.1) WPD make a number of assumptions over which elements of the price control settlement to treat as operating costs and which elements to treat as capital costs. The cost drivers used to allocate operating and capital costs to the network levels are different. Therefore the assumptions made on whether to categorise certain elements of the price control settlement as operating or capital costs, can affect the overall allocation to network levels.

1.22. The allocation is not an exact science and different views could be taken on certain items. The within year ex post allowed revenues will vary from those set at the price control as a result of a number of factors. These are not considered separately by WPD and are implicitly allocated between operating costs, depreciation and return in the

[22] WPD use private networks as they state they have no experience of IDNOs connecting at HV in their area and private networks provide the best proxy.
[23] In this instance downstream competitors refers to the IDNOs operating the 'last mile' of the distribution network.

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same proportion as the price control settlement analysis. Whilst this would seem sensible for some items such as the correction factor, it would be possible to identify some specific items such as network rates that could be the subject of specific allocation drivers.

We would ask respondents to consider;

Is the approach of dissecting the price control settlement into operating costs, depreciation and return a suitable cost reflective approach?

Is it appropriate to apply the cost allocation percentages derived from price control data, recent year RRP data and forward looking capex projections to ex post allowed revenues?

Capital costs

1.23. The choice of allocation driver for the capital costs is crucial as this represents 65% of allowed revenues. As described in the summary above, WPD apply the same cost driver to allocate both depreciation and return between voltage tiers and use FBPQ net capex as the most appropriate cost driver. This represents the average planned capital expenditure on the network between 2008-2015. WPD choose net rather than gross additions to take account of the fact that some capital additions to the network are funded by customer contributions within the connection charge, or are adopted free of charge from a developer. WPD state these assets do not enter the RAV (regulatory asset value) and that consequently, they do not earn depreciation or return on them until such time as they replace them with new assets.

1.24. Within WPD's modification report Appendix 2 contains a more detailed description of how the FBPQ net capex is calculated.

1.25. We ask respondents to consider the following questions;

Do WPD's proposals to calculate the capital costs associated with their business and allocate them to network levels using FBPQ net capex better meet the relevant objectives? Is it appropriate to use the same allocation driver for depreciation and return?

Is it appropriate to use FBPQ data which is based on forward looking capex estimates rather than actual, or historical capex spend?

Does WPD's use of FBPQ net capex to apportion both depreciation and rate of return not restrict, prevent or distort competition compared to WPD's current methodology?

Treatment of operating costs

1.26. Operating costs constitute around 35% of total costs for both WPD's DSAs (distribution service areas). WPD use MEAV (modern equivalent asset value) to allocate the majority of the operating costs which are not already allocated to network levels in RRP data. The MEAV of WPD's two networks by network level are as follows:

Table 1.6- MEAV split of WPD's networks

	EHV	HV	HV/LV	LV
WPD West	22%	26%	7%	45%
WPD Wales	23%	27%	7%	43%

1.27. WPD argue that MEAV is a good indicator of network scale and that all the activities which they allocate by MEAV are driven by network scale. WPD include some

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regression analysis on page 8 of their modification report. This demonstrates a high correlation between MEAV (as a measure of network scale) and both total direct and indirect operating costs of all 7 DNO groups. They state that the indirect costs within RRP data are not affected by direct activities. In addition, they highlight that in the period 2005/6 – 2007/8 network investment activity increased by 27.6% across all DNOs whilst indirect costs remained unchanged. WPD also argue that MEAV takes account of substation costs in a way which network length (an alternative measure of scale which results in different allocations) does not.

1.28. It is worth noting that WPD propose to include the MEAV of their entire network, and do not exclude services or the proportion of the LV network which is funded by customer contributions. This can make a significant difference to the cost allocation as shown below;

Table 1.7 – alternative MEAV allocation of WPD's network levels

WPD West	EHV	HV	HV/LV	LV
MEAV excluding 100% of LV service cables	26%	31%	8%	35%
MEAV excluding 100% of LV service cables & 50% of LV mains	31%	37%	10%	21%
WPD .Wales				
MEAV excluding 100% of LV service cables	27%	32%	8%	33%
MEAV excluding 100% of LV service cables & 50% of LV mains	32%	39%	9%	20%

1.29. WPD state that MEAV is the best measure to use since they have to undertake activities on all parts of their network regardless of whether it was funded by the customer or not.

1.30. Respondents should note that the MEAV allocation is applied only to those costs which are not already allocated to network levels in RRP (except those which WPD do not allocate according to any specific cost driver - see Annex 2 for details of which costs WPD state are unallocated). We would ask respondents to consider the following questions;

Do respondents agree with WPD's assessment that MEAV is the most appropriate (and cost reflective) cost driver to allocate those operating costs not split within RRP data? Please justify your answer.

Do respondents consider that this method of identifying the operating costs associated with different network levels, better meets the relevant objectives?

Treatment of pensions and incentive revenue

1.31. As has been explained above, WPD apply their overall percentage allocation between network levels to allowed revenue. However, WPD decided to remove pension deficit and annual incentive revenue (positive or negative) from allowed revenue before applying the allocation.

1.32. Pension deficit is the legacy costs which WPD have on historic pension provisions. These pensions come from the electricity supply pension scheme (ESPS). After privatisation the various privatised companies assumed responsibility for the ESPS. These companies are directed to protect the scheme by statute[24] to ensure that scheme members are no worse off than they would have been had the scheme continued.

[24] The relevant statutes are:
- The Electricity (Protected Persons) (England and Wales) Pension Regulations 1990 (SI 1990/346) and
- The Electricity Supply Pension Scheme (Eligible Persons) Regulations 1990 (SI 1990/164).

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1.33. WPD argue that pension deficit costs arising from this scheme is a cost which they cannot avoid and will remain with them irrespective of how many IDNOs connect to their system in both the short and long term. As such, they state that it is inappropriate to allocate these costs upstream and downstream of the point of connection. The effect of the decision to exclude the pension deficit allowance from allowed revenue, results in a lower allocation of costs to each network level and thus a smaller discount on the 'all the way' charge. The pension deficit amount included in allowed revenues is recovered from all customers on a p/kWh basis. The result of this is that customers connected to an IDNO will pay the same contribution to pension deficit as customers on the DNO network

1.34. WPD have also excluded incentive income from allowed revenues before they allocate to network levels. The incentive revenue comes from a variety of schemes in the current price control package;

- The DG (distributed generation) incentive provides a financial incentive to facilitate economic DG connections;
- The losses incentive financially rewards DNOs if they beat a target level based on historical performance and penalises them if they under perform;
- There are a number of quality of service measures;
    - the interruption incentive scheme provides rewards or penalties for the number of customer interruptions per 100 customers (CI scheme) and the number of customer minutes lost (CML);
    - there is an incentive in place that penalises or rewards DNOs based on the results of ongoing customer surveys on their call handling performance;
    - DNOs are penalised if they fail to meet a range of guaranteed standards of performance relating to customer service; and
    - there is a customer service reward scheme that DNOs can compete for if they can demonstrate leading performance, innovation and excellence in dealing with priority customer care initiatives, corporate social responsibility and wider communications strategies.
- An information quality incentive mechanism incentivises DNOs not to inflate their forecasts and gives extra income to DNOs for forecast spend close to Ofgem's assessment as well as providing those DNOs with a higher incentive rate to increase their rewards for outperformance;
- An innovation funding incentive allows DNOs to earn up to an extra 0.5 % of regulated revenue to invest in research and development;
- A registered power zone incentive provides a DNO with extra revenue over and above the main DG incentive where they develop new and more cost effective strategies for connecting and operating DG.

1.35. WPD argue that any income (positive or negative) they receive from these incentives should not be allocated upstream and downstream of the point of connection. WPD argue that to include this revenue would result in an increase or decrease in IDNO margins as a result of the good or poor performance of WPD against the various incentive schemes. Respondents should also consider that in order to earn incentives, a DNO is likely to have to incur extra costs.

1.36. The table below illustrates the difference which removing pension deficit and incentive income can have on the allocation of costs to voltage levels and thus on the value of the discount available to IDNOs. The impact may be very different for other DNOs whose incentive income may be larger, smaller or negative and whose pension deficit allowance is greater or smaller.

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Table 1.8 % allocation of total costs to voltage levels

	EHV	HV	HV/LV	LV
WPD Wales				
As proposed (excluding pension deficit and incentives from allowed revenue)	25.4%	27.3%	12.6%	31.1%
Including both pension deficit and incentives in allowed revenue	26.4%	28.3%	13.1%	32.2%
Including pension deficit only in allowed revenue	26.1%	28.0%	13.0%	31.9%
Including incentive revenue only in allowed revenue	25.7%	27.6%	12.8%	31.4%
WPD West				
As proposed (excluding pension deficit and incentives from allowed revenue)	26.2%	17.9%	11.8%	37.9%
Including both pension deficit and incentives in allowed revenue	27.9%	19.1%	12.6%	40.4%
Including pension deficit only in allowed revenue	27.1%	18.5%	12.2%	39.2%
Including incentive revenue only in allowed revenue	27.1%	18.5%	12.2%	39.1%

1.37. Including both incentive payments and in year pensions deficit[25] can have the following impact upon the average boundary charges[26] and gross IDNO margins:

Table 1.9 – Difference pension deficit and incentive income makes to average domestic bill and gross margin

WPD Wales	Band 1	Band 2	Band 3	Band 4	HV DOM
Estimated annual bill for average IDNO site on proposed tariff	£5,480	£5,703	£5,899	£6,125	£8,385
Estimated annual bill for average IDNO site if Pensions and incentive income included	£5,398	£5,621	£5,843	£6,066	£8,181
Difference in estimated annual DUoS bill	£82	£83	£56	£59	£204
% Difference	1.49%	1.45%	0.95%	0.97%	2.43%
IDNO gross margin	£2,488	£2,266	£2,070	£1,843	£6,555
Difference as % of IDNO gross margin	3.28%	3.64%	2.72%	3.21%	3.11%
WPD West					
Estimated annual bill for average IDNO site on proposed tariff	£4,621	£5,043	£5,470	£5,899	£7,011
Estimated annual bill for average IDNO site if Pensions and incentive income included	£4,421	£4,875	£5,330	£5,806	£6,534
Difference in estimated annual DUoS bill	£200	£168	£141	£93	£477
% Difference	4.34%	3.33%	2.57%	1.58%	6.80%
IDNO gross margin	£2,803	£2,381	£1,954	£1,531	£6,909
Difference as % of gross margin	7.15%	7.06%	7.21%	6.07%	6.90%

[25] The year taken in this instance was 2007/8.

[26] These boundary charges are based on an illustrative IDNO site with WPD specific tariffs and the following assumptions:
80 plots on LV IDNO site, 150 plots on HV DOM IDNO site. Average consumption of 4000kWh, with 85%/15% split between day and night. Due to lack of data on the average consumption, the number and mix of end customers on a HV and LV Non Dom site, we have not included this in our analysis.

1.38. The specific WPD data demonstrates that when incentive income is positive, the decision to exclude it reduces IDNO margins. Respondents should equally consider that if incentive income is negative then the decision to exclude it would increase IDNO margins.

Questions for respondents:

Is it appropriate for WPD to exclude pension deficit from allowed revenue before allocating it between network levels?

Is it appropriate for WPD to exclude in year incentive income received/deducted from allowed revenue before allocating it between network levels?

Does WPD's proposal to exclude pension deficit and incentive income from allowed revenue better achieve the relevant objectives?

Basis of allocating LV and HV network costs between WPD and IDNOs

1.39. As described in the summary of WPD's proposals, they retain their distance related banded approach for LV domestic customers and also introduce banding for their new non domestic LV IDNO tariffs. However, the method WPD propose differs from that which they currently have in place. WPD propose to divide the total cost allocated to the LV into a fixed and variable element according to the indirect and direct proportion of operating costs in RRP data. As explained earlier, the direct portion of the costs are then reduced as the IDNO connects in bands further away from the HV/LV substation. These bands are calculated on the average length of the network which WPD calculate as being 256 metres. IDNOs connecting within 0-64 metres of the HV/LV substation are allocated a Band 1 tariff, 65-128 metres a Band 2 tariff, 129-193 metres Band 3 and 194 metres+ in Band 4.

1.40. IDNOs have suggested that this banding approach encourages them to lay duplicate mains to connect closer to the transformer than would be required on efficiency grounds in order to obtain a greater discount. They argue therefore that this approach is inefficient and not cost reflective.

1.41. At HV, WPD argue that the interconnected nature of the network means that distance related charges are not appropriate. For predominantly domestic IDNOs, WPD propose to set the boundary charge on the basis of a discount on all components of the domestic restricted (DOM R) end charge which is calculated by the sum of the costs allocated to the HV/LV transformer and the cost associated with operating the LV network level. For WPD Wales this produces a 44% discount and for WPD West this produces a 50% discount on the end tariff.

1.42. For predominantly non domestic HV IDNOs, WPD propose a different method which sets the boundary charge on the basis of a discount on all components of the HV half hourly tariff, including capacity charges.

1.43. WPD calculate the discount by firstly allocating the costs allocated to the HV between a fixed and variable element based on the proportion of indirect and direct costs in RRP allocated to the HV voltage level in a similar way to the LV. 100% of the fixed element is provided as a discount, plus 15.8% of the variable element. This 15.8% is calculated by looking at the average length of private networks[27] connected within WPD's DSAs, compared to the average length of network for WPD's own HV end customers.

1.44. In WPD West the allocation to HV is 18% and in WPD Wales the allocation is 27%. Following the allocation of these costs into a fixed and variable element and

[27] WPD use private networks as they say that they have no experience of IDNOs connected at HV in their DSA's and private networks are the next best proxy.

application of the 15.8% factor the discount for WPD West is 14% and for WPD Wales is 19.2%.

1.45. We invite views from respondents on the following specific issues:

Is it more cost reflective for WPD to use the proportion of direct to indirect costs as a way of identifying the fixed and variable elements of the 'all the way' discount?

Does banding restrict, distort or prevent competition in Distribution? Is it more cost reflective for WPD to differentiate between HV and LV and propose bands solely at LV?

Does WPD's creation of IDNO specific tariffs for non domestic LV IDNO sites and IDNO specific tariffs at HV better achieve the relevant objectives?

Is it cost reflective for WPD to distinguish between HV domestic and HV non domestic in the manner in which they calculate the respective tariffs?

Do WPD strike an appropriate balance between cost reflectivity and not restricting competition in their use of a domestic restrict tariff structure for all domestic IDNO tariffs?

Impact analysis

1.46. We have undertaken analysis to look at the margins available to IDNOs under WPD's proposals. The table below shows WPD's proposed tariffs as a percentage of the existing tariffs which they have in place at LV and HV. It also compares the margins to those available under WPD's current IDNO tariffs.

1.47. The table below highlights the margin per plot which is available for IDNOs under all the tariffs WPD have produced. This analysis makes a number of assumptions; consumption of 4000kWh for domestic and 75,000kWh for non domestic customers, both with daily consumption split 85% day and 15% night. We have also assumed that capacity ramps up over time in line with the total number of plots.

1.48. Furthermore, for simplicity we assume that domestic sites are 100% domestic and non domestic sites are 100% non domestic where the IDNO can recover capacity charges from all end customers. This results in neutral margins under WPD's current tariffs, on the basis that a non Domestic LV IDNO will be charged the LV HH tariff and will charge all non domestic customers end customers on the same LV HH tariff. We would stress that this is an illustrative example of an IDNO site used for comparative purposes. It will not always be the case that all end customers on an IDNO LV non domestic site are charged on the LV HH tariff. For the HV non domestic sites, we have assumed that all IDNO end customer are LV non domestics who IDNOs charge on the basis of WPD's LV HH tariff.

1.49. We would ask respondents to consider the following questions:

Does WPD's proposal prevent, restrict or distort competition in distribution compared to their current IDNO charging methodology?

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Table 1.10 – Per plot margin under current and proposed methodologies

IDNO per plot margin	West			
	Proposed	**Current**	**Difference**	**Difference as %**
LV domestic Band 1	£35.04	£24.82	£10.22	41.18%
LV domestic Band 2	£29.76	£21.98	£7.78	35.40%
LV domestic Band 3	£24.42	£19.48	£4.94	25.36%
LV domestic Band 4	£19.14	£16.64	£2.50	15.02%
LV non domestic Band 1	£283.98	£0.00	£283.98	n/a
LV non domestic Band 2	£241.25	£0.00	£241.25	n/a
LV non domestic Band 3	£196.03	£0.00	£196.03	n/a
LV non domestic Band 4	£153.30	£0.00	£153.30	n/a
HV Domestic	£46.06	£45.50	£0.56	1.23%
HV non Domestic	£518.07	£477.53	£40.54	8.49%
	Wales			
	Proposed	**Current**	**Difference**	**Difference as %**
LV domestic Band 1	£31.10	£30.76	£0.34	1.11%
LV domestic Band 2	£28.32	£27.98	£0.34	1.22%
LV domestic Band 3	£25.88	£25.54	£0.34	1.33%
LV domestic Band 4	£23.04	£23.04	£0.00	0.00%
LV non domestic Band 1	£229.00	£0.00	£229.00	n/a
LV non domestic Band 2	£213.87	£0.00	£213.87	n/a
LV non domestic Band 3	£191.24	£0.00	£191.24	n/a
LV non domestic Band 4	£173.62	£0.00	£173.62	n/a
HV Domestic	£43.70	£50.46	-£6.76	-13.40%
HV non Domestic	£488.33	£431.60	£56.73	13.14%

Annex 2 - IDNO/DNO working group consultation

2. Background

2.1. In July 2008, Ofgem started to facilitate a series of without prejudice meetings between IDNOs and DNOs. The purpose of these meetings was to provide a forum for IDNOs to provide their views on IDNO charging. The group subsequently agreed to develop a common IDNO charging methodology in two stages; an interim proposal to be implemented in April 2009; leading to an enduring proposal to be implemented in April 2010 as part of the common distribution charging methodology.

2.2. The working group has been unable to agree a common interim methodology on IDNO charging. WPD developed their own IDNO charging methodology independently of the working group and submitted it to the Authority as a formal modification request – as described in Annex 1. CE have been restricted in their ability to fully engage in the working group as a result of their own legal advice and consequently they have independently developed IDNO charging proposals and presented their emerging thoughts to the working group. The remaining DNOs have developed IDNO charging methodologies based around an approach devised by Reckon LLP. This is referred to as the Reckon methodology throughout this document.

2.3. All three methods are distinctly different both to each other (although each can be classified as a top-down average accounting approach) and from the existing DRM based methodology for setting end consumer tariffs.

2.4. As stated at the covering letter to this consultation, the IDNO/DNO working group must now focus on developing the enduring IDNO charging methodology. In order to provide the impetus for DNOs and IDNOs to do this, we set out in this annex:-

- A summary of the CE approach (which is described in more detail in a discussion document prepared by CE and published as a sub document to this consultation)
- A summary of the Reckon approach and its variants
- A comparison of these approaches with the WPD approach (which was discussed in Annex 1) including a review of the difference between the existing DRM based models and the proposed approaches;

2.5. We welcome views on which approach, and importantly which aspects of the various methodologies, are appropriate for an enduring common IDNO charging methodology. It is worth reiterating that we view this comparative exercise as a completely separate process from the assessment of formal modification proposals which are submitted to us for implementation ahead of April 2010.

CE's proposal

Summary of CE's proposal

2.6. CE do not currently have any specific IDNO tariffs and so in common with all other DNOs (other than WPD) they charge IDNOs on the basis of commercial end user tariffs. They are proposing to introduce tariffs for:-

- Two new customer groups for LV IDNO connections (predominantly domestic customers and predominantly non-domestic customers)
- Two new customer groups for HV IDNO connections (predominantly domestic customers and predominantly non-domestic customers)

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2.7. CE also propose to offer IDNOs a choice of tariffs at HV. At HV, IDNOs may opt for a tariff structure that includes a fixed charge and a single p/kWh or an alternative that include a fixed charge, a p/kWh rate plus a capacity charge element for those IDNOs that wish to reserve capacity beyond their immediate needs.

2.8. In order to establish IDNO boundary tariffs CE have proposed a move away from the DRM (an incremental) method of charging IDNOs towards an AAC (a top down) method. However, unlike WPD, CE do not allocate their costs between operating costs and capital (depreciation and return) based on the price control settlement but instead they use actual costs and existing tariffs – see CE's discussion document which is published as a separate document alongside this consultation.

2.9. CE identify the operating and capital costs by assuming that operating costs are recovered via the fixed charge element of their existing tariffs and capital costs are recovered by the unit charge.

2.10. CE allocate, operating costs across network components (in this case LV, HV & EHV) by looking at RRP data. A portion of direct costs are directly attributed to network levels in the RRP. The remaining direct costs are allocated to network levels pro-rata to the directly attributed costs. The remaining operating costs (indirect and pass through items) are allocated according to an appropriate cost allocation driver. CE has made efforts to identify the most appropriate allocation driver for each category of costs. These are shown in more detail in the table below. We compare CE's approach to other approaches in later in this Annex.

Table 2.11 – CE cost drivers and cost types

Driver & cost types	Rationale
Net Capex Network policy, Network Design & Engineering; Project management, engineering management & clerical support; stores; network rates	Activities most directly affected by capital programmes
Length of network System mapping, vehicle & transport; property management; health & safety & operational training	Costs which vary most significantly in relation to the length of the network and hence distance travelled
Substations Control centre; wheels imported	Costs are generated by the requirement to control flow at substations
Units exiting Transmission exit charges	
Customers Customer call centre; IT & Telecoms; HR & non-operational training, finance & regulation, CEO; Ofgem licence fee	Costs which vary most significantly by customer numbers

The table below shows the amount of each cost allocated to each network level according to the selected allocation driver.

2.11. The net effect of the various operating cost drivers is that about 45% of operating costs are allocated to the LV in CE's two DSAs.

2.12. For the capital costs, CE use their internal forecast of capex for the next ten years net of customer contributions as the allocation driver. This capital expenditure is largely directly attributable to each network component and hence CE use the proportion of net capital expenditure allocated to each network component as the basis of a discount on an weighted average of LV domestic or non domestic unit charges to arrive at IDNO tariffs for LV domestic and LV non domestic unit charges.

Table 2.12 – Percentage allocation of CE cost drivers

Drivers	EHV	HV	LV
Allocation of direct costs in RRP	16%	32%	52%
Net Capex	40%	36%	24%
Length of network	8%	46%	46%
Substations	1%	99%	0%
Units exiting	13%	20%	67%
Customers[28]	0	0	100%

2.13. Table 1.13 below illustrates the allocation of CE's 10 year net capex forecast plan to the network levels:

Table 2.13 – Percentage of CE net capex plan per network level

	EHV	HV	LV
NEDL	40%	26%	24%
YEDL	36%	36%	28%

2.14. CE has proposed varying the level of discount on the LV system according to the capacity required by the IDNO. The greater the capacity requirement of the IDNO (compared to the average capacity availability of an LV main) the greater the discount from the ATW tariff on the basis that capacity requirement and use made of the CE LV network are inversely correlated. CE are proposing five capacity related bands ranging from 20% to 100%.

2.15. Further detail on CE's proposals can be found in their draft discussion paper published alongside this document.

What do respondents think of the CE approach and in particular its novel features such as optional capacity reservation facility and banding according to capacity?

Reckon proposals

Summary of Reckon proposals

2.16. The approach developed by Reckon takes a staged approach to identify the appropriate costs and therefore charges imposed by DNOs on IDNOs who connect to their network.

2.17. The stages are:-

- Identify the average revenue, normalized to p/kWh, recovered from customers connected to the LV network
- Allocate total operating costs, as indentified in the RRP, to each network component[29] in proportion to direct operating costs directly attributed to network components. These costs are normalised to a p/kWh value.
- Allocate replacement expenditure (again as indentified in the RRP, and used here as a proxy for depreciation) to each network component in proportion to replacement expenditure directly attributed to each network level in the RRP. Again these costs are normalised to a p/kWh value.

[28] Due to rounding it appears that there are no customers at EHV and HV. This is obviously not the case and simply reflects that for simplicity, no decimal places have been used in this table.
[29] Under the Reckon method, network components are: GSP, 132kV, 132/33kV sub, 33kV, 33/11kV sub, 11kV, 11/LV sub, LV network, LV service cables.

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- Allocate reinforcement expenditure (again as indentified in the RRP) to each network component in proportion to reinforcement expenditure directly attributed to each network level reported in the RRP. The costs are normalised to a p/kWh value.

- The difference between average p/kWh LV revenue and allocated operating costs and replacement expenditure is designated as the "return element" and this is then allocated to each network component. As we explain below there are three possible alternative methods for achieving this allocation – the core method as presented to the working group plus 2 variants which have since emerged.

- The sum of the LV p/kWh operating cost, replacement cost (depreciation) and reinforcement cost (return) allocations as a proportion of the total LV revenue p/kWh costs of all network components is calculated.

- The basis of the IDNO discount on the 'all the way charge' is calculated as the proportion of costs allocated to the LV network component multiplied by the average IDNO LV main usage.

2.18. As with the WPD approach the Reckon approach therefore endeavors to allocate the three traditional price control categories of operating costs, depreciation and return to network components. The resulting LV allocation is used as a basis for calculating the IDNO discount on the 'all the way' charge. However, there are differences between the two in terms of the sources for the costs that are used in the allocation, the cost drivers used in the allocations, the precise definitions of network components and the calculation of the proportion of LV main used by IDNOs. We provide a more detailed description of some of the key stages of the Reckon method below.

Allocation of Operating Costs

2.19. Using RRP operating cost data, operating costs directly attributed to each network component are allocated to the various network components[30]. All remaining operating costs (excluding pass through items) are allocated to the network components pro-rata to the direct costs. We note that typically for DNOs less than one third of operating costs have been directly attributed to network components in the RRP.

Allocation of Depreciation

2.20. Reckon take the view that replacement expenditure is a good proxy for depreciation associated with replacement. They use the RRP data on replacement expenditure as the basis for their allocation of depreciation to the network components. Directly attributed replacement expenditure is allocated to the network components and the balance of replacement expenditure is allocated in proportion to this. Within the RRP most replacement has been directly attributed to a specific network component.

2.21. We note that for price control purposes a proportion of replacement expenditure is added to the RAV; however no adjustment is made for this in the Reckon methodology. In addition no comparison is made to establish whether replacement is broadly equivalent to depreciation.

Allocation of Return

After Reckon have normalised the operating costs and replacement costs allocated to all network components by the number of units flowing through that component they deduct the sum of these two values from the average revenue in p/kWh recovered from LV customers to calculate the "return" element of this revenue. This return element will be associated with all network components and not just the LV system.

[30] We note that, unlike the WPD approach, the Reckon approach does not make an adjustment for direct operating costs which have been treated as capital expenditure in the price control and added to the RAV

Allocation in proportion to direct reinforcement capex (as described in working group meeting of 5 March)

To identify the LV portion Reckon allocate the return elements in proportion to the general reinforcement expenditure directly attributable to each network component, using the figures taken from RRP. The assumption is that the return element of charges is to provide a return to allow DNOs to finance new investment, with replacement expenditure largely being financed either by upfront customer contributions or on a "pay as you go" basis.

Where RRP data on general reinforcement does not include substation costs, these costs are allocated to the network levels in the same proportion as asset replacement expenditure on substations (for which figures are available).

2.22. As we mentioned previously two alternative methods have developed since the methodology was presented to the working group for allocating the return element to the LV network. It is not clear why the two variants have been developed but it is worth noting that the core method results in very low levels of return allocated to the LV network, due to the very low levels of general reinforcement at that network level. We describe each below:

1) Allocation of total "net capex" in proportion to total (reinforcement and replacement) capex

In this version replacement capex is not allocated to the network tiers on the basis of directly attributable replacement expenditure. Instead, this variant allocates all costs except operating costs to the return element. The return element allocated to the network components in proportion to total directly attributable (replacement and reinforcement) capex – referred to as the 'net capex' version.

2) Replacement cost adjuster

Reckon have also devised a further method by which to allocate a return. Unlike the core method this does not assume that replacement capex is funded entirely by upfront customer contribution or on a "pay as you go" basis. This method seeks to calculate a required rate of return on replacement capital investment by an IDNO on the basis that it would require the same return as a DNO. Return associated with reinforcement expenditure is calculated as it is in the first method.

This method starts from the assumption that a part of the initial capital expenditure on new assets is funded by upfront customer contributions. In the simplest case, which we outline here, customer contributions contribute 100% of the new asset cost. In this case the downstream operator undertakes no capital expenditure until the end of the useful asset lives. Assuming an average asset life of 40 years and a required rate of return of 6.9% then an annuity calculation would suggest that remuneration of 7.41% p.a. of the initial investment is required to cover a rate of return of 6.9% and depreciation.

As, under this scenario, the downstream operator will not undertake capital expenditure for 40 years then to generate an annual value for the remuneration of replacement capex to be recovered from year 1, the annuity must be discounted. Reckon argue that because, unlike most of the upstream capital expenditure, the downstream operator has not been required to fund capital expenditure upfront then the risk associated with this investment over the first 40 years is significantly lower that associated with the DNOs capital expenditure programme. Therefore Reckon use an assumed risk free rate of 2% to discount back the annuity 40 years. This gives an annuity from year one of 3.36% of initial investment (in year 40).

On a straight-line basis the annuitized depreciation (approximated here by replacement capex) suggests that 2.5% of investment will be remunerated in each of the 40 years of asset life. Thus, Reckon suggest that a "reasonable profit" on replacement capex for an

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IDNO would be a 35% (3.36%/2.5%) uplift on allocated replacement capital expenditure.

Calculating the IDNO discount

2.23. Having established the return element associated with the downstream network. The discount from the ATW tariff can be calculated as the sum of allocated LV operating costs plus LV replacement plus LV return (on a p/kWh basis).

2.24. The final stage in the Reckon approach is to take into account where the IDNO network connects to the DNO network. Whereas the WPD approach takes distance from the transformer into account and the CE approach capacity of the embedded network, the Reckon approach calculates the proportion of the LV network used by the IDNO on a per end user basis. This is calculated, on a DNO average basis, as average length of IDNO main per customer divided by average length of IDNO main per customer plus average length of DNO main used per IDNO customer. Typical values of these are 15m and 2.5m respectively resulting in a discount of 85% of the LV mains cost (plus 100% of the LV services)

2.25. Table 2.14 below illustrates the allocation of capital costs to the LV network level for each variant of the Reckon methodology. It uses input data from 3 DNOs to allow comparisons to be made. As can be seen from the table, the repex adjuster option consistently provides for a slightly greater allocation to the LV and the net capex option a significantly greater allocation.

Table 2.14 – Comparison of Reckon methods of applying capital costs to the LV network

Company	Reckon Variant	Repex LV allocation	Return LV allocation	Total LV allocation
DNO 1	Original	31.9%	1.2%	22.74%
	Net capex	0.0%	23.6%	32.02%
	Repex adjuster	31.9%	6.9%	24.46%
DNO 2	Original	21.6%	12.4%	24.75%
	Net capex	0.0%	20.8%	28.78%
	Repex adjuster	21.6%	14.8%	25.78%
DNO 3	Original	32.5%	7.0%	31.04%
	Net capex	0.0%	29.8%	39.05%
	Repex adjuster	32.5%	15.2%	33.05%

Reckon proposals for the structure of IDNO tariffs

2.26. There are three also variants of the Reckon methodology when it comes to the structure of the tariff, two site specific variants and a portfolio variant. This site specific options apply to LV connected IDNOs only. For HV and EHV connected IDNOs, the standard commercial tariff will still apply.

Site specific variant 1:

2.27. Variant 1 invoices the IDNO on a site basis according to the units consumed at the boundary meter and it categorizes the site as either domestic or non domestic according to the maximum demand. Those sites where the maximum demand is greater than 60% domestic are classed as domestic. Those sites where the maximum demand is less than 40% domestic are classed as non domestic. Where a site has between 40-60% of maximum demand from domestic customers the classification of the site is by agreement between the IDNO and DNO.

2.28. An LV domestic site will have the overall discount calculated according to the above method(s) applied to the unit charges of an average domestic tariff[31]. It will have a fixed charge based on the average domestic tariff and discounted on the basis of the method outlined above. The discounted fixed charge will be levied according to the number of MPANs on the IDNO site. The IDNO will be asked to submit MPAN data to the DNO between the 15th and last day of the month. Where the IDNO is unable to provide this information the DNO will make an estimate.

2.29. An LV non domestic site will have the overall discount calculated according to the above methodology applied to the unit charges of the LV HH tariff. The fixed charge will work on the same principle as for domestic sites. However, where the IDNO is able to state the number of its MPANs which are domestic within the non domestic site, these will be charged on the basis of the discounted domestic fixed charge rather than the discounted LV HH fixed charge.

Site specific variant 2:

2.30. This variant concentrates solely on an LV IDNO tariff and applies the discount calculated on the method to the DNO domestic restricted tariff. As in the site specific variant 1 approach, the discounted fixed charge is levied according to the number of MPANs on the IDNO site. The IDNO will need to provide this data to the DNO on a monthly basis. Where no data is forthcoming the DNO will make an estimate of the number of MPANs on the IDNO site. This tariff is available for domestic and non domestic IDNOs.

Portfolio variant:

2.31. A further variant of the tariff structure is to base tariffs on a portfolio approach. This produces the following specific tariffs, applying the fixed discounts calculated for both LV, HV and EHV;

Table 2.15 – Range of tariffs available to IDNOs under portfolio approach

	Voltage of connection		
	LV	**HV**	**EHV**
Dom UR	•	•	•
Dom R	•	•	•
PC 3	•	•	•
PC 4	•	•	•
PC 5-8	•	•	•
HH LV	•	•	•
HH HV	n/a	•	•
Unmetered	•	•	•

2.32. These tariffs will be applied on a DSA wide basis. The DNO will then produce a bill for the totality of LV Domestic customers on IDNO sites in its DSA, the totality of non domestic customers on IDNO sites in its DSA, the totality of half hourly metered customers on IDNO sites in its DSA etc. The method also allows potentially different discounts to be provided to the IDNO depending on the voltage of connection (VoC) of the IDNO site. For instance the tariff levied on an IDNO for an end customer where the IDNO VOC is at EHV will be different from the tariff levied on an IDNO for an end customer where the IDNO VOC is at LV. This method requires the IDNO to provide the DNO with information over the number of end customers on each tariff and their consumption to a level which is satisfactory to the DNO.

2.33. Where the IDNO is unable to provide this information, the DNO will charge them a choice of a Dom UR or Dom R tariff, discounted on the method outlined above to reflect

[31] This average domestic tariff is an average of PC 1 & PC 2 unit charges.

all 3 possible points of connection (LV, HV or EHV) for an IDNO site. This allows the IDNO to chose the structure of the end tariff which best fits their site.

What do respondents think of the Reckon approach in general and its novel features such as the portfolio approach to tariff structure?

Comparative analysis

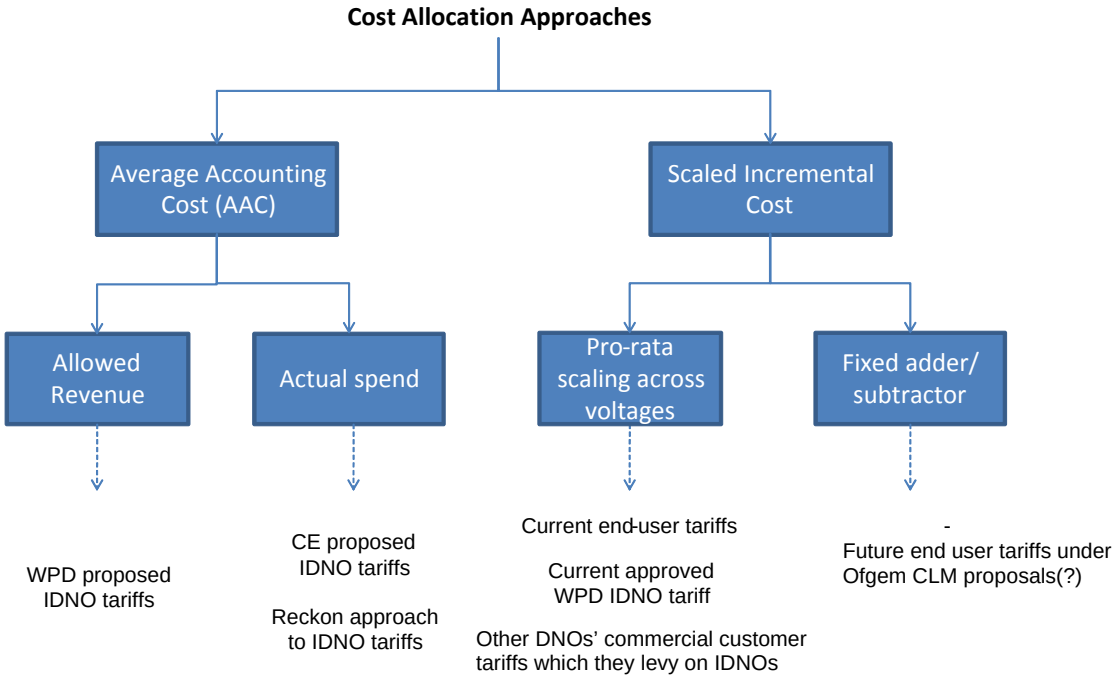
2.34. It is instructive, not least for the enduring solution, to compare a number of key elements of the different solutions being proposed / discussed. The enduring solution will need to make some key decisions with regard to:

- The choice between an Average Accounting Cost based approach or an Incremental cost based approach;
- The basis for allocating capital costs (if an AAC type approach is used);
- The basis for allocating operating costs;
- The structure of IDNO tariffs (banded vs portfolio) and the proportion of HV/LV costs included in the boundary charge.

Top down Vs Incremental

2.35. As illustrated in Figure 1.3, the WPD, CE and Reckon approaches are all variants of an Average Accounting Cost based approach to cost allocation, and as such, represent a significant departure from Incremental Cost based approaches to setting DUoS tariffs, which are currently applied to end users.

Figure 2.3 – Approaches to setting tariffs



2.36. GB electricity DUoS tariffs for end users have been calculated using engineering models, known as Distribution Reinforcement Models (DRM) to estimate the incremental flows with the objective of charging users according to the incremental cost they place on the network, scaled to the DNO's revenue requirements. For some DNOs pure (pre-scaled) incremental cost based tariffs would have returned less revenue than allowed under the price control, so the scaling has had the effect of increasing tariffs above pure incremental

cost. For other DNOs pure incremental cost based tariffs would have returned more revenue than required, so the actual tariffs are scaled down incremental costs. Whilst there is some variation in how DNOs have applied the scaling, DNOs have generally applied the same percentage scaling to tariffs at each voltage tier. Therefore costs have been allocated to the different voltage tiers in proportion to the *incremental* cost of each voltage tier.

2.37. With the exception of WPD, DNOs currently charge IDNOs on the same basis as end customers and so IDNO boundary charges reflect Scaled Incremental Costs. Whilst WPD has specific IDNO tariffs, these also reflect Scaled Incremental Costs, albeit net of estimated avoided cost and with the percentage scalar applied not to the total yardstick but to the sum of the yardstick up to 11kV.

2.38. In the course of working with DNOs to develop an industry consensus on IDNO boundary charges, IDNOs have expressed concerns that DRM based approaches are not appropriate for the purposes of setting IDNO boundary charges, and may not result in appropriate allocations of cost, including fixed costs and overheads. They have also expressed concerns about the lack of transparency with regard to the DRM used by each DNO. These models differ in structure from DNO to DNO, are not in the public domain and are not transparent to IDNOs.

2.39. IDNOs have stated that they favour a "top-down" type approach as often used in competition tests for margin squeeze, which allocate the DNOs' costs to the upstream network (upstream of the IDNO POC) and downstream network based on the average costs of service, i.e. an Average Accounting Cost (AAC) approach.

2.40. The WPD, CE and Reckon approaches are all AAC type approaches. However, a key distinction can be drawn between the WPD approach which uses Allowed Revenues as the amount of cost to be allocated, and the Reckon approach which is based upon allocation of a DNO's actual operating replacement and reinforcement spend, taken from Regulatory Reporting Pack (RRP) data reported by each DNO to Ofgem annually. Allowed Revenue reflects the level of spend that Ofgem deemed appropriate for the efficient operation of each DNO at the last price control (DPCR4). The WPD reliance on price control numbers allows them to impute how much of the Allowed Revenue was required in respect efficient opex, depreciation and return on capital. The WPD apportionment of costs into opex, depreciation and return on capital therefore reflects Ofgem's DPCR4 view of efficient operation and price control accounting treatment.

2.41. The CE approach is a hybrid of the two other approaches. It does not use allowed revenue or actual spend directly but uses the revenue recovered from its fixed charge. This is used on the basis that the revenue from the fixed charge covers pure operating costs and the revenue recovered from the unit charge based on DRM scaled to allowed revenues as a proxy for capital costs.

2.42. The Reckon approach relies on one year of actual spend to apportion expenditure between different categories. Clearly actual spend can be higher or lower in any given year, particularly if capital investment is "lumpy". This approach does not "smooth out" capital investment, but effectively treat it as if it was expensed in year. Whilst the Reckon approach use only one year of RRP data, in principle, it would be possible to average over a number of years. This may smooth out peaks and troughs in investment spend to some extent, although there is a limit to the number of years of historical RRP returns that exist. The WPD approach, in reflecting price control accounting, reflects the fact that in reality, a DNO recovers the depreciation and return on the asset over its accounting life[32]. The CE approach uses only one year of operating cost data and incremental capital costs. As operating costs do not display as much volatility as capital expenditure and incremental cost will be more stable than actual capital costs, charges should be reasonably stable.

[32] Based on RAV depreciation rates, which may differ from Regulatory or Statutory Accounts depreciation rates.

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2.43. It should be noted that while the choice of Allowed Revenue / Actual Spend approaches affect the proportion of costs which are badged as opex, depreciation and return for the purposes of allocation to different network voltages. The total revenues which are allocated are the same in all approaches since the Actual Spend approaches are calibrated back to the ATW tariff, which is determined by Allowed Revenue. However, it should be noted that since that opex, depreciation and return costs drivers potentially allocate very different percentages of cost to different voltage components, this can make a material difference to boundary charges.

2.44. An alternative approach often used for cost allocation is a Long Run Average Incremental Cost methodology (LRAIC). The European Commission defines LRAIC as "the average of all the (variable and fixed) costs that a company incurs to produce a particular product. LRAIC and average total cost (ATC) are good proxies for each other, and are the same in the case of single product undertakings"[33]. Thus for a single product undertaking, the Commission appears to be defining LRAIC in a similar way to which Average Accounting Cost[34] is defined above. The Commission state that LRAIC is one of the methodologies which they will use to determine whether an incumbent has abused a dominant position and state that, "Failure to cover LRAIC indicates that the dominant undertaking is not recovering all the attributable) fixed costs of producing the good or service in question and that an equally efficient competitor could be foreclosed from the market.

2.45. We note that the one of the options being considered for the enduring solution is to base charges on the DRM being developed as part of the Common Licence Modification (CLM) for the purposes of end-user HV/LV charging. We note that it is planned that there will be a change to the way in which scaling will be applied in the common HV/LV approach, relative to the way that DNOs have applied scaling in the past, and this will have material impacts on boundary charges, if applied in the enduring solution.

2.46. At the moment, DNOs typically apply scaling pro-rata across the voltage tiers, hence if pure incremental costs are less than allowed revenues, charges for use of each voltage tier are scaled up in the same proportion. Conversely, if pure incremental costs are greater than allowed revenue, then charges for each voltage tier will be scaled down in the same proportion. However, under the CLM approach, scaling will be applied via a fixed adder (which will be positive for those DNOs that need to scale up from incremental cost to Allowed Revenue, and negative for those DNOs that needs to scale down from incremental cost to Allowed Revenue). A fixed adder has the effect of allocating a higher proportion to EHV and HV as the pure unscaled costs at these voltage levels are lower than at LV. Hence, for those DNOs that scale up, it will have the effect of compressing the differential between HV and LV tariffs relative to pro-rata scaling, and for those DNOs that scale down, it will have the effect of increasing the differential between HV and LV tariffs relative to pro-rata scaling. Hence, if this approach is also applied to IDNO boundary charging tariffs, relative to pro-rata scaling a fixed adder will have the effect of reducing the gross margins to IDNOs connecting to DNOs that scale up and increasing the IDNO gross margins where a DNO scales down.

2.47. The rationale for employing a fixed adder for end user charging is that by maintaining the absolute differential between HV and LV incremental costs, it provides appropriate investment signals to end customers. However, this approach does not necessarily facilitate competition between alternative potential distribution operators. There is no necessary presumption that exactly the same approach must be used for setting end-user DUoS charges and IDNO boundary charges, and it should be recognised that one of the relevant objectives, which is more relevant to IDNO boundary charges than end-user charges is that the UoS charge "does not restrict, distort, or prevent competition in the transmission or distribution of electricity".

[33] See footnote 18 of, "Guidance on the Commission's enforcement priorities in applying Article 82 of the EC Treaty to abusive exclusionary conduct by dominant undertakings".
[34] The Commission use the term AAC for Average Avoidable Cost, which is different from Average Accounting Cost as defined here. The Commission state that Average Avoidable Cost only includes fixed costs if incurred during the period under examination.

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2.48. Respondents should consider the following questions;

Is it more appropriate for an enduring solution to IDNO charging to be based on a 'top down' AAC allocation approach or a scaled incremental cost approach such as the one based on the DRM?

Does the answer to the above depend to any extent on the way that scaling is applied?

If respondents consider that an AAC based approach is most appropriate, should this be based on an allowed revenue approach or an actual spend approach?

If respondents consider that a DRM based approach is most appropriate, does there need to be any adjustments to the current approach to reflect differences between end user tariffs and charges for embedded networks.

Please set out any adaptations of any of the above approaches that should be reflected in the enduring solution, or propose which alternatives for the enduring solution you consider appropriate. Where alternatives are proposed, please specify the rationale for your preference.

Capital costs

2.49. The regulatory framework distinguishes two elements of capital costs, depreciation of investment and return on investment. If the enduring solution is to be based on an AAC type approach, then a methodology for allocating capital costs needs to be defined (if a DRM type approach is used, the engineering model allocates it based upon required spend at each voltage level to serve the increment).

2.50. The WPD, CE and the Reckon approaches all use quite different methods to identify what constitute capital related costs (depreciation and return on capital) although the methods of allocating it between different voltage levels are more closely aligned.

2.51. As set out in Annex 1 (table 1.1), the WPD approach uses price control data to determine what proportion of costs are depreciation, and which are return. The level of depreciation and return which have been reflected in the DPCR4 Allowed Revenue settlement are explicitly itemised and publicly available.

2.52. WPD have then allocated both elements of the capital costs, depreciation and return using forecast net capex spend by voltage tier. The data is sourced from Forecast Business Plan Questionnaires (FBPQs) which are submitted by each DNO to Ofgem. FBPQs are one of the key inputs into the price control (DPCR5), and have forecast net capex spend for the remainder of the DPCR4 period and the DPCR5 period. Net capex means net of customer contributions, i.e. the amount of investment that the DNO funds itself (and is therefore included in the RAV) as opposed to that which is paid for by upfront connections charges levied on customers. The argument for allocating based on net capex rather than gross capex, is that the regulatory regime only allows DNOs to recover depreciation costs and to earn a return on capital on their own investment funds, not on investment funded upfront by the customer. Therefore in the case of a new connection funded by the customer, the majority if not all of the investment will not be reflected in the RAV since it is recovered through connection charges. However, when those assets need to be replaced, the expenditure is funded by the DNO, not the customer and is reflected in the RAV (and would be reflected in FBPQ) at that point. Note that DNOs have replacement expenditure since they have a mix of old and new assets, so such an apportionment of costs reflects the cost structure of the DNO. IDNOs, which have a younger asset base compared to lives of distribution assets will not incur replacement expenditure for a number of years, thus should have significantly less net capex than DNOs albeit they may make adoption payments.

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2.53. WPD have used the split of future net capex between voltage tiers as a proxy for the split of the capital costs between voltage tiers, given that we understand that the data does not exist to provide an "audit trail" between physical assets and the RAV (both elements of allowed capital cost, depreciation and return are a direct function of the RAV, so if the data existed to disaggregate the RAV into voltage tiers, it would be logical to incorporate this data into the approach instead of using a proxy). Note that in the WPD approach the future net capex spend projections are used only to allocate the capital costs between tiers, not to determine what proportion of costs are capital. By contrast, the Reckon approach uses RRP data to determine what proportion of revenues are represented by operating costs and depreciation, and the proportion that is return is identified by the residual. The core Reckon approach takes expenditure on asset replacement as a proxy for depreciation, and capital expenditure on reinforcement as the allocation driver for return on capital. The Reckon approach has two variants. The first allocates depreciation and return by net capex reported from RRP in a similar way to WPD (but using a one years' worth of actual costs rather than the seven years' forecast costs) and the second which uplifts this by 35% to allocate a reasonable profit . CE assumes that all income recovered from their unit charges represent capital costs. They then allocate these to network levels according to their own internal 10 year net capex forecast instead of using FBPQ.

2.54. There seems to have been only a limited number of options considered to allocate capital costs in the three approaches reviewed to date. Ideally in the WPD allowed revenues approach actual RAV allocated to the voltage tiers would be used. WPD use forecast net capex as its allocation driver. However, this is a forward looking indicator rather than an attempt to ascertain what is included in the current RAV. CE also use forward looking net capex plans although they use an internal forecast rather than the more public FBPQ. Reckon use a mixture of actual replacement and general reinforcement expenditure although only for a single year. There have been no suggestions of using alternative drivers such as MEAV or length of mains or indeed historical RAV additions (even although all methods seek to some extent to disaggregate allowed revenues). Given that depreciation and return account for the majority of costs this is an area that will have a significant impact on allocations to the various voltage levels.

2.55. Respondents should consider the following questions;

Which method to estimate the proportion of revenues attributable to capital costs do you think is the most appropriate?

Which method to allocate estimated capital costs do you think is the most appropriate?

Should the same allocation driver be used for depreciation and return?

Should DNOs be able to more directly attribute RAV costs to each network level on the basis of past capital expenditure and depreciation rates?

Which method to allocate a return on capital do you think is the most appropriate?

Operating costs

2.56. The three approaches all use significantly different methods to ascertain the level of revenues attributable to operating costs. As set out in Annex 1 WPD used the price control settlement to establish the relevant percentage applicable to operating costs and apply this percentage to with-in year allowed revenues after making two adjustments. Reckon use an apportionment of RRP actual costs (excluding pass through items) as the appropriate level of operating costs whilst CE use the fixed charges arising from the DRM model as the basis of operating costs.

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2.57. It is important to obtain the most appropriate allocation to operating costs as the allocation to network levels and hence boundary charges varies between operating and capital costs.

2.58. Once the level of operating costs is established each approach takes a different approach to the allocation of the operating costs to the network levels.

2.59. Table 2.16 below outlines the different views which WDP, CE and Reckon have adopted.

Table 2.16 – Different cost drivers used for operating costs

Cost Category	WPD	Reckon	CE
Load related new connections & reinforcement (net of contributions)	Split known	Split known	Split known
Non-load new & replacement assets (net of contributions)	Split known	Split known	Split known
Non-operational capex	Split known	Split known	Split known
Faults	Split known	Split known	Split known
Inspections, & Maintenance	Split known	Split known	Split known
Tree Cutting	Split known	Split known	Split known
Network Policy	MEAV	Pro rata	Net Capex
Network Design & Engineering	MEAV	Pro rata	Net Capex
Project Management	MEAV	Pro rata	Net Capex
Engineering Mgt & Clerical Support	MEAV	Pro rata	Net Capex
Stores	MEAV	Pro rata	Net Capex
Network rates	Pro rata		Net Capex
System Mapping - Cartographical	MEAV	Pro rata	Length of network
Vehicles & Transport	MEAV	Pro rata	Length of network
Property Mgt	Pro rata	Pro rata	Length of network
Health & Safety & Operational Training	MEAV	Pro rata	Length of network
Control Centre	MEAV	Pro rata	Substations
Wheeled units imported	n/a	Pro rata	Substations
Customer Call Centre	MEAV	Pro rata	Customer
IT & Telecoms	Pro rata	Pro rata	Customer
HR & Non-operational Training	MEAV	Pro rata	Customer
Finance & Regulation	MEAV	Pro rata	Customer
CEO etc	MEAV	Pro rata	Customer
Ofgem licence fee	n/a	-	Customer
Transmission exit charges	EHV only	-	Units distributed

2.60. There is commonality over the use of the costs directly attributable to network levels in the RRP and the use of the RRP cost categories.

2.61. For those costs that are not directly attributable to voltage levels in the RRP, different cost drivers have been used. WPD choose a single allocation driver, MEAV, to reflect the size of the network which WPD argue is the best indicator of the level of indirect costs. However, this may not be relevant in deciding how to allocate between network levels. Reckon also use a single cost driver and in their case they allocate all other costs (except pass through costs) on the basis of the directly allocated costs – an equi-

proportional approach. However, for most DNOs the proportion of costs directly attributed is relatively low and hence the bulk of costs allocated on the basis of a minority of the costs. In contrast endeavour to identify an appropriate cost driver for each activity, reflecting to some extent the causality of the cost category. In this respect their approach is similar to the exercise undertaken by Ofgem in its DCPR5 policy paper and there is some overlap in the selected drivers as shown in the table below. A contrast with CE's approach can be seen in CE's use of net capex which does not seem to correlate to investment activity, where a stronger causality may be found by using in sourced capex or gross capex.

Table 2.17 – Initial Ofgem view of cost drivers for DPCR 5[35].

Cost category	Allocation Driver
Faults, inspections & maintenance, tree cutting	Directly attributed to network levels
Network policy, network design & engineering, project management, system mapping,	Network investment activity
Engineering mgmt & clerical support, control centre, customer call centre, stores, health & safety & operational training,	Network investment and network operating costs activity
Vehicles & transport	Insourced network investment and network operating cost activity
Finance & regulation	Network scale

2.62. It is quite difficult to compare the various approaches as the impact on each network will vary depending upon the physical characteristics and the cost structure of each network. In order to overcome some of these issues we have used a common data set – using WPD data for both WPD South West and WPD South Wales and applied the three main operating cost drivers. The results are shown in the table below.

Table 2.18 – Comparison of different operating costs drivers on allocation of operating costs to LV

% Allocation	WPD	Reckon	CE
WPD South West	44%	54%	49%
WPD South Wales	38%	42%	47%

2.63. As can be seen from the above table although the values are in the same broad area of 40-50% allocated to the LV, the range is quite significant especially terms of the gross margins available to the IDNOs.

2.64. It is particularly noteworthy that the range on the Reckon approach is so broad. This is because small changes in the proportion of costs in the direct cost activities will have a significant impact on overall cost allocation. In the WPD method the direct costs also have a reasonably significant impact because they also affect unallocated costs which are quite significant as they include network rates. In contrast the CE approach seems

[35] http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/POLICY%20PAPER%20APPENDICES.pdf p 94.

reasonably stable because they select an allocation driver for all cost categories and therefore the impact of the direct costs is minimised.

2.65. It should be noted that these results are based on the WPD data set and the WPD method (other than choice of cost allocation driver). Slightly different results would be obtained if the different cost drivers were used within the Reckon or CE approaches.

2.66. Respondents should consider the following;

Which method to respondents think is the most appropriate for identifying operating costs and why?

Which methodology do respondents think is the most appropriate for allocating operating costs to network levels and why?

Allocation of LV and HV network costs between transformer and the point of connection

2.67. All the suggested approaches make an adjustment to boundary charges where the IDNO point of connection is not directly at the transformer. This is to reflect the partial usage made of the voltage tier where the connection takes place. As set out in the description of each approach earlier in this document the method of estimation is different for each approach and also between the LV and the HV.

2.68. At LV both WPD and CE use bands to estimate the use made of the system. However, WPD use distance between the transformer and the point of connection whilst CE use the capacity of the site. The portion of the costs allocated to the LV and included in the discount from the "All The Way" charges varies from 25-100% in the case of WPD and 20-100% for the CE approach. In both approaches the boundary charge will vary significantly depending upon the specific characteristics of the IDNO network – either locationally within the LV network or capacity related.

2.69. Reckon, in contrast, estimate the average use made of the LV network by IDNO networks in general and apply the average discount to all IDNO networks. Although Reckon use distance as the cost driver (as with WPD) they use the proportion mains length provided by the IDNO compared to the DNO on an average length of main per customer basis.

2.70. The IDNOs argue that site specific features should not affect the boundary charge as the incremental costs of where they connect on the network are marginal and that as their costs do not vary by location the margin between boundary charges and "All the Way" charges (which do not vary by location) should not be affected. They highlight competition tests for margin squeeze to support this approach and suggest that boundary charges should reflect all the costs allocated to the LV network. In addition, they suggest that the locational price effects of the WPD approach provide an incentive on them to duplicate mains to enable them to connect closer to the transformer and obtain a larger discount. They argue therefore that such an approach would be inefficient and not cost reflective.

2.71. At HV, only the CE approach reflects within its charges any IDNO network specific features. The CE capacity related approach is applied in the same way.

2.72. WPD argue that the structure of the networks is different at HV compared to LV and therefore length is not a cost driver. They instead use two different methods depending on whether the IDNO connection is predominantly domestic or non-domestic. For domestic connections a fixed discount to the domestic unrestricted tariffs is provided based on 100% of the costs allocated to the LV network and the HV/LV transformer. No reduction is applied for any partial use made of the HV system. In contrast for non-domestic connections a fixed discount is estimated based on average length of HV mains generally provided by private HV networks. This is not dissimilar to the Reckon approach

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at LV although WPD use actual length rather than the length per customer metric preferred by Reckon.

2.73. An issue which all approaches have to deal with is the situation of mixed sites of domestic and non-domestic customers. WPD and CE deal with this by labelling sites as predominantly domestic and predominantly non-domestic and altering charges accordingly. Reckon include a portfolio approach in their tariff structure options which removes the need to classify sites as each IDNO customer is attributed to their specific customer class and invoices provided on a customer class basis across the whole DNO.

2.74. There is a variety a methods being advocated for allocating the LV and HV costs between DNOs and IDNOs. These are all described in detail within the summary of proposals and are listed below as a reminder;

1) WPD distance banding

2) CE Capacity banding

3) Reckon site specific variant 1

4) Reckon site specific variant 2

5) Reckon Portfolio approach

Do respondents consider that it is appropriate to reflect partial use made of the network level to which the IDNO connects in boundary charges? If yes, should boundary charges reflect site specific details or be set on an average basis? And if on a site specific basis what is the appropriate cost driver?

Do the WPD and CE approaches result in appropriate changes in boundary charges to reflect the costs of partial use of the network?

Which method of allocating LV & HV costs between DNO and IDNO do respondents consider is the most cost reflective?

Are there aspects of the different approaches which respondents consider could be used for the enduring IDNO charging methodology? Please justify your answer in terms of cost reflectivity and not restricting competition

We would also invite respondents to evaluate all of the approaches outlined above and the extent to which they are appropriate for an enduring IDNO charging methodology.

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Annex 3 – Summary of Consultation questions

Questions from Annex 1: Formal consultation on WPD UoS 012

Whether WPD's proposal to use a top down AAC avoided cost approach is more cost reflective than their current DRM avoided cost approach?

Whether WPD's proposal to use a top down AAC avoided cost approach does not restrict competition in distribution compared to their current methodology?

Whether it is appropriate and cost reflective to make a distinction between the methods used to calculate charges to IDNOs and end customers?

Whether it is appropriate to use the AAC method to provide a discount on the end customer charge derived from the incremental DRM?

Is the approach of dissecting the price control settlement into operating costs, depreciation and return a suitable cost reflective approach?

Is it appropriate to apply the cost allocation percentages derived from price control data, recent year RRP data and forward looking capex projections to ex post allowed revenues?

Do WPD's proposals to calculate the capital costs associated with their business and allocate them to network levels using FBPQ net capex better meet the relevant objectives? Is it appropriate to use the same allocation driver for depreciation and return?

Is it appropriate to use FBPQ data which is based on forward looking capex estimates rather than actual or historical capex spend?

Does WPD's use of FBPQ net capex to apportion both depreciation and rate of return not restrict, prevent or distort competition compared to WPD's current methodology?

Do respondents agree with WPD's assessment that MEAV is the most appropriate (and cost reflective) cost driver to allocate those operating costs not split within RRP data? Please justify your answer.

Do respondents consider that this method of identifying the operating costs associated with different network levels, better meets the relevant objectives?

Is it appropriate for WPD to exclude pension deficit from allowed revenue before allocating it between network levels?

Is it appropriate for WPD to exclude in year incentive income received/deducted from allowed revenue before allocating it between network levels?

Does WPD's proposal to exclude pension deficit and incentive income from allowed revenue better achieve the relevant objectives?

Is it more cost reflective for WPD to use the proportion of direct to indirect costs as a way of identifying the fixed and variable elements of the 'all the way' discount?

Does banding restrict, distort or prevent competition in Distribution? Is it more cost reflective for WPD to differentiate between HV and LV and propose bands solely at LV?

Does WPD's creation of IDNO specific tariffs for non domestic LV IDNO sites and IDNO specific tariffs at HV better achieve the relevant objectives?

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Is it cost reflective for WPD to distinguish between HV domestic and HV non domestic in the manner in which they calculate the respective tariffs?

Do WPD strike an appropriate balance between cost reflectivity and not restricting competition in their use of a domestic restrict tariff structure for all domestic IDNO tariffs?

Does WPD's proposal prevent, restrict or distort competition in distribution compared to their current IDNO charging methodology?

Questions from Annex 2: IDNO/DNO working group options for enduring solution

What do respondents think of the CE approach and in particular its novel features such as optional capacity reservation facility and banding according to capacity?

What do respondents think of the Reckon approach in general and its novel features such as the portfolio approach to tariff structure?

Is it more appropriate for an enduring solution to IDNO charging to be based on a 'top down' AAC allocation approach or a scaled incremental cost approach such as the one based on the DRM?

Does the answer to the above depend to any extent on the way that scaling is applied?

If respondents consider that an AAC based approach is most appropriate, should this be based on an allowed revenue approach or an actual spend approach?

If respondents consider that a DRM based approach is most appropriate, does there need to be any adjustments to the current approach to reflect differences between end user tariffs and charges for embedded networks.

Please set out any adaptations of any of the above approaches that should be reflected in the enduring solution, or propose which alternatives for the enduring solution you consider appropriate. Where alternatives are proposed, please specify the rationale for your preference.

Which method to estimate the proportion of revenues attributable to capital costs do you think is the most appropriate?

Which method to allocate estimated capital costs do you think is the most appropriate?

Should the same allocation driver be used for depreciation and return?

Should DNOs be able to more directly attribute RAV costs to each network level on the basis of past capital expenditure and depreciation rates?

Which method to allocate a return on capital do you think is the most appropriate?

Which method to respondents think is the most appropriate for identifying operating costs and why?

Which methodology do respondents think is the most appropriate for allocating operating costs to network levels and why?

Do respondents consider that it is appropriate to reflect partial use made of the network level to which the IDNO connects in boundary charges? If yes, should boundary charges reflect site specific details or be set on an average basis? And if on a site specific basis what is the appropriate cost driver?

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Do the WPD and CE approaches result in appropriate changes in boundary charges to reflect the costs of partial use of the network?

Which method of allocating LV & HV costs between DNO and IDNO do respondents consider is the most cost reflective?

Are there aspects of the different approaches which respondents consider could be used for the enduring IDNO charging methodology? Please justify your answer in terms of cost reflectivity and not restricting competition

We would also invite respondents to evaluate all of the approaches outlined above and the extent to which they are appropriate for an enduring IDNO charging methodology.

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