NETWORK BENEFITS FROM INTRODUCING AN ECONOMIC METHODOLOGY FOR DISTRIBUTION CHARGING

A STUDY BY THE DEPARTMENT OF
ELECTRONIC & ELECTRICAL ENGINEERING
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1 BACKGROUND & INTRODUCTION

Background

1. This study has been commissioned by Ofgem to examine whether other charging methodologies would be more efficient at encouraging the economic development of the distribution network. In its consultation on the longer term structure of distribution charges[1] Ofgem noted that it expected distribution network operators (DNOs) to advance solutions that would overcome the weaknesses in the current charging arrangements. The weaknesses identified included the inability to reflect forward looking costs, lack of any distinction in the cost of siting at different locations, little recognition of the cost of reactive power flows, and inconsistency in the treatment between generation and demand.

Aims of this Study

2. The scope of this study is to demonstrate whether there are potential benefits that could arise from changes to the DNO charging regimes, and thus help inform the consideration of any new charging framework. The associated analysis seeks to simulate the impact of any new charging regime on network development costs based on the response of new and existing network users. The study is intended to extend to both distributed generation and load.

3. The main focus of the study has been on the impact a new charging methodology would have on extra high voltage (EHV) networks. Consequently in this study the modelling of likely price changes that could emerge from a change of pricing methodology is restricted to the EHV part of the system. However, because all users of distribution networks make use of the EHV distribution system the impact on both customers connected at EHV and those connected further down the system will need to be considered.

4. The benefits that may be derived from a change to the charging methodology are measured in relation to the future investment likely to be needed on the system. The analysis seeks to simulate the prospective developments of the system given the changed pattern of the growth in demand and distributed generation. Using the

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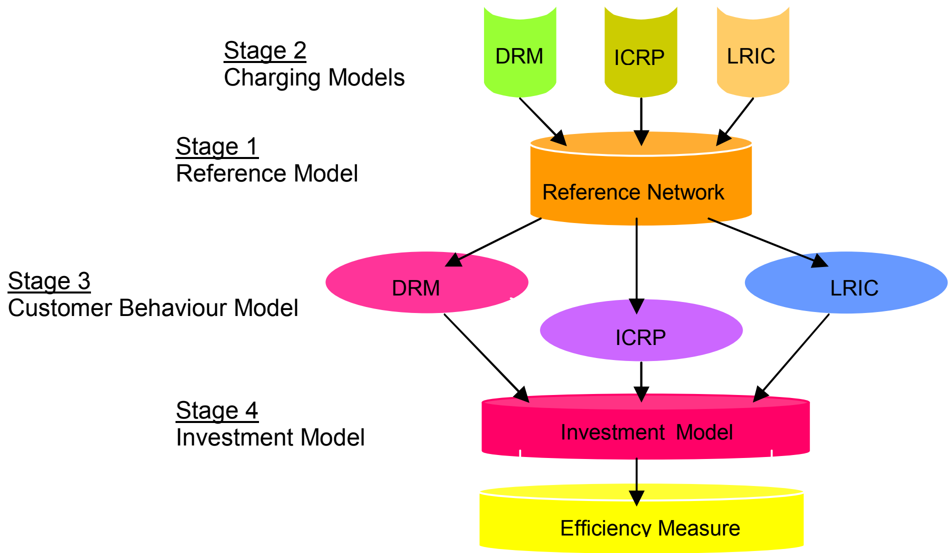
[1] Structure of electricity distribution charges – Consultation on the longer term charging framework. 9th May 2005

existing charging methodology as the benchmark, the efficacy of different charging methodologies is assessed from the investment needed to meet the requirements of load and distributed generators that use the system over the term of the study. The study covers the 20 years from 2005 to 2025

Study Outline

5. The study has been conducted in four stages. These are shown diagrammatically below. The four stages are described in the subsequent chapters of this report. Issues that have arisen in developing the models and analysing the relevant data are also considered in each section. Inevitably a considerable number of assumptions have been made to produce a coherent analysis. Where assumptions have been adopted these are clearly stated and when appropriate their rationale given.

Study Approach



Reference Network

6. The first stage has been to devise a reference EHV network. The network is not necessarily typical of those found generally but is intended to demonstrate the consequence of changing the charging methodology for parts of the network that demonstrate specific characteristics. Although based on real asset configurations, the network should not be associated with any part of the system.

7. The reference network that has been devised is described more fully in Section 2. It comprises assets that serve three distinctive areas. It has been modelled as a series of nodes interconnected by lines, cables and transformers, with load and generation connected such that DC and AC power flow studies can be conducted. An associated asset register and price controlled revenue target enables the application of a DRM model to assess the charges that might apply under present pricing practices if the area were a self contained distribution system.

Distribution Charging Models

8. In stage 2 five pricing models are contemplated that produce a range of prices:
   - DRM with site specific EHV charges. This model is intended to reflect broadly the present charging arrangements for load supplied from distribution networks. The pricing of generation use of system is not an intrinsic part of the model.
   - DC load flow with ICRP. This model utilises the same approach as for the present transmission charging arrangements.
   - AC load flow with ICRP. AC load flows reflect more accurately the use that is made of a system since they also take account of reactive power. They tend not to be used for transmission on grounds of their complexity and the size of the associated data sets.
   - DC load flow with LRIC. The LRIC model utilises the same DC load flow calculation as for ICRP but the treatment of costs is different
   - AC load flow with LRIC. This employs the same AC load flow variations as for the ICRP but now with the LRIC cost model

   In presenting the analysis the output from the DRM model is used as the benchmark against which the ICRP and LRIC models can be tested.

9. The pricing models are chosen so that the consequence of moving from the classic distribution reinforcement model (DRM) for setting charges to one based on economic principles can be explored. It is not the purpose of this study to form a view as to the most appropriate form of charging model that might be adopted, but rather to examine the consequences of adopting a different approach for distribution use of system charging. The nature of these pricing models and an analysis of their output is considered in Section 3.

Customer response

10. In order to determine the response of customer demand to prices derived from the various charging models, and thus the subsequent impact on system investment, a customer behaviour model has been developed (stage 3). For the generic customer classes connected at LV and 11kV price elasticities taken from published studies are used to derive anticipated changes in demand following a change in price. However, in the reference network half of industrial load is connected at EHV. EHV connected load is assumed be more price elastic than industrial load connected at lower voltages. Growth in this load is a taken to arrive as new large customers that site on an economically rational basis and choose those locations that have the lowest connection cost and use of system charges. The characteristics of these models and their outputs are described further in <u>Section 4</u>.

11. In creating a customer response model for distributed generation we have adopted the underlying assumption that the government's target for the connection of distributed generation will be achieved. The amount of distributed generation connecting to the reference network over the study period has been derived as a proportion of the load served by the network. This proportion reflects the national average in each year of the study period. As for EHV connecting load, distributed generation is assumed to connect as discrete projects at those locations that provide the best rate of return for the project. The mechanics of the model that determines the appropriate location for the siting of distributed generation in any year of the study period is described further below.

Impact on network investment

12. Finally in the fourth stage of the study the consequence of differing patterns of demand and distributed generation on network investment that flow from customer reaction to the various pricing models is examined in an investment model. The nature of this model and its outputs are examined in <u>Section 5</u> of the report. The respective costs developing the distribution network to accommodate demand and generation is used as the measure of the effectiveness of the charging methodology in encouraging efficient investment and thus the relative benefit of moving away from the present charging arrangements. <u>Section 6</u> of the report draws together the various conclusions and observations that emerge from this study.

2 REFERENCE NETWORK

System Assets

13. In order to explore the impact of the differing charging approaches on customer behaviour and thus the requirement for future investment, a reference network has been devised. This is based on a real system that has been generalised to provide a simpler test bed for assessing the investment consequences of the various pricing models. Only EHV assets at 132kV and 33 kV have been modelled at this time since it is anticipated that the case for moving to economic distribution charging methodologies must first be demonstrated at these voltages.

14. The reference network encompasses three grid supply points (GSP) serving areas characterised by different proportions of residential, commercial and industrial load. The system has both 132/33 kV and 33/11kV transformations, as well as 132/11kV transformers. It is described as a series of nodes connected by lines and cables. Unlike the ICRP model of the transmission network employed in charging studies it considers the costs of transformers and sub-station switchgear to be a marginal cost interposed between low and high voltage nodes at different points on the network.

15. This enables the network to simulate the existing DRM that is used to derive distribution charges, and also investigate the locational signals both by voltage and geographic dispersion. Overall the reference network has 275 MW of load and 10 MW of distributed generation connected to it in the base year. The MEA value of the assets expressed as an annuity for this network is a little over £7 million. The target revenue permitted under the price control is taken to be a multiple of the annualised asset cost and is assumed to be £8.6 million in the first year of the study.

16. **Area 1** represents an urban area. It has predominantly residential load connected to four 33 kV or 11 kV bus-bars. The proportions of residential, industrial and commercial load in the base year (2004) are respectively 50%, 15% and 35%.

Bus-bar	Voltage	Residential Load		Industrial Load		Commercial Load	
		MW	MVAr	MW	MVAr	MW	MVAr
1	11 kV	14.90	3.31	4.47	1.91	10.43	3.48
2	33 kV	44.62	12.13	13.38	7.02	31.23	12.77

3	11 kV	6.70	1.67	2.01	0.97	4.68	1.76
4	33 kV	11.10	1.71	3.33	0.99	7.77	1.80
5	11 kV	7.40	1.14	2.22	0.66	5.18	1.20

17. **Area 2** is an industrial area. It is supplied from a conventional 132/33 kV bulk supply point (BSP). The proportions of residential, industrial and commercial load connected in this area in the base year are respectively 15%, 75% and 10%. A dummy node (node 6) is inserted at an intermediate point on the 33 kV network. Initially this has no load connected to it but provides a location where large customers and generation could connect in the future.

Bus-bar	Voltage	Residential Load		Industrial Load		Commercial Load	
		MW	MVAr	MW	MVAr	MW	MVAr
6	33 kV	0.00	0.00	0.00	0.00	0.00	0.00
7	33 kV	8.61	4.01	44.10	22.22	6.15	4.36

18. **Area 3** is a rural area. It has relatively little industrial load, and because of its sparse population density displays long distances between adjacent nodes. The proportions of residential, industrial and commercial load in this area in the base year are respectively 25%, 60% and 15% connected to 3 bus-bars. The 33 kV network has been meshed to reflect the need to support voltage in this part of the network. A dummy node (bus-bar 9) has been inserted where future distributed generation, and potentially large customers, might locate.

Bus-bar	Voltage	Residential Load		Industrial Load		Commercial Load	
		MW	MVAr	MW	MVAr	MW	MVAr
8	11 kV	2.92	2.08	7.00	8.85	1.75	1.94
9	33 kV	0.00	0.00	0.00	0.00	0.00	0.00
10	33 kV	16.18	3.62	0.00	0.00	9.72	3.38
11	11 kV	13.05	1.95	0.00	0.00	7.83	1.82

Large Industrial loads

19. The industrial load connected to the network includes two large industrial customers connected at bus-bars 2 and 7. These have the following characteristics:

Bus-bar	Voltage	Site specific loads*	
		MW	MVAr
2	33 kV	6.69	3.51
7	33 kV	22.05	11.10

** included in area industrial loads above*

Distributed Generation

20. So that the impact of distributed generation can be investigated, the reference network incorporates distributed generation at Bus 7 and Bus 8. The characteristics of this generation are as follows:

Bus-bar	Technology	Connection voltage	Installed MW	Typical MVAr
5	CHP	33 kV	5.88	1.19
7	Wind	33 kV	3.92	0.80

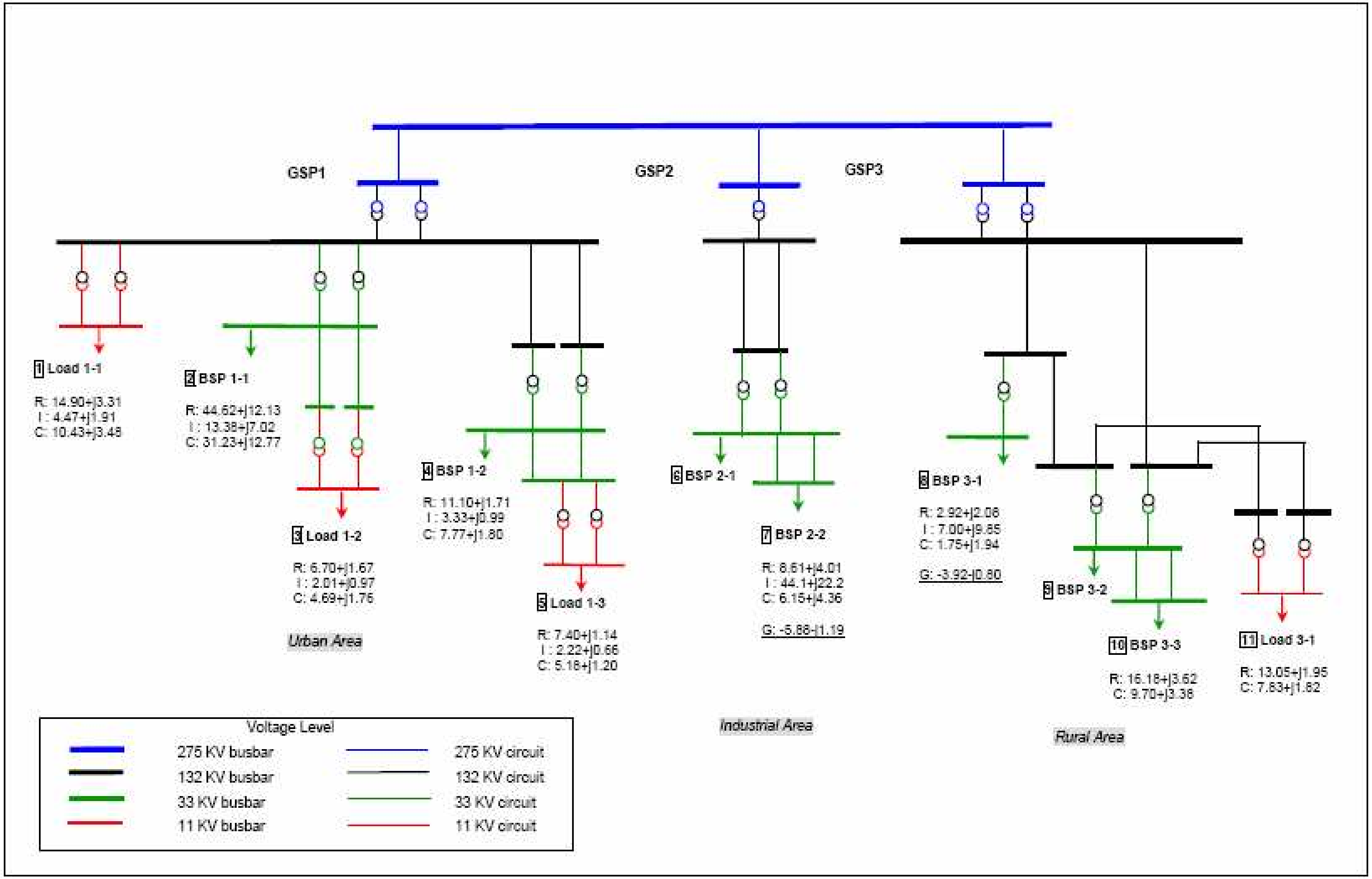
System security

21. The security of a distribution system is subject to the provisions of Engineering Recommendation P2/5. P2/5 specifies the expected restoration times for loads of varying sizes in the event of fault conditions. However, for simplicity we have assumed an empirical relationship between the system capacities needed to meet demand and the connected load. At voltages of 33 kV and above it is assumed that the capacity needed for the system to be compliant with P2/5 must be twice the load supplied. Had the study been extended to lower voltages then differing factors would have been applied that reflected the lower security permitted under P2/5, albeit offset by the inherent over-capacity that results from the use of standard sized assets.

System Schematic

22. The diagram below shows schematically the various parts of the reference network together with the connected load and generation in the base year. The notation used in this diagram is to show the connected load and generation at each node as a combination of a MW and MVAr (represented by “j”) quantity.

Reference Network with connected load and generation



3 PRICING MODELS

Principal features

23. The five distribution pricing models contemplated in this study are a DRM cost allocation model, two ICRP models based on the marginal costs derived from a consideration of DC and AC load flow studies, and two LRIC models based on DC and AC load flow studies. The principle features of these different approaches to deriving network charges can be summarised as follows:

DRM (cost allocation)

- Prices vary with voltage of connection
- Prices do not vary with location
- Charges reflect the cost of the existing assets valued on a MEA basis
- Generation charges can not be derived directly from the model

ICRP Models (DC and AC load flow variants)

- Prices are derived on a nodal basis and thus vary with both voltage and geographic location
- Charges reflect system conditions at times of peak demand
- The model naturally produces both demand and generation charges
- Charges for generation and demand are symmetrical, i.e. both have the same absolute value but a different sign
- Costs reflect the in situ system valued on an MEA basis
- The AC variant produces separate reactive power charges

LRIC Models (DC and AC load flow variants)

- Prices are produced on a nodal basis and thus vary with both voltage and geographic location
- Charges reflect system conditions at times of peak demand
- The model naturally produces both demand and generation charges, but these are not symmetrical
- The AC variant produces separate reactive power charges
- Costs reflect the timing and size of future investment needed to meet incremental demand or generation

DRM Charging Model

24. The DRM model has been in existence for over 25 years as a basis for deriving distribution charges. It is essentially an allocation model that attributes the costs of the existing network to users depending upon the use they make of each voltage level of the distribution system, as inferred from their maximum demand and customer class characteristics. The structure chosen for the DRM in this study follows the approach that is most prevalent amongst DNOs.

25. The DRM is used as the benchmark against which the consequence of moving to other distribution use of system pricing models can be compared. In accordance with the general approach taken in formulating the DRM, the assets that comprise the reference network have been re-valued at their modern equivalent asset value (MEA), and their cost expressed as an annuity to determine the annual capital recovery necessary to sustain the investment. The amount is increased by a £/kW supplement such that for all users the charges will recover revenue equal to that permitted under the price control. The reference network that has been devised has 275 MW of connected load and 10 MW of distributed generation at the start of the study period. Consequently it has been necessary to scale the network such that it represents an incremental 500 MW extension to the distribution system.

26. Capital charges are obtained by applying an annuity factor of 7.41% (which assumes a commercial asset life of 40 years and a 6.9% rate of return) to the MEA value of the assets. A £/kW supplement is then added to annual cost to provide the revenue recovery permitted under the price control. The charges derived from the model for each level of the system are tabulated below.

Annual costs of reference network in 2005

Voltage or Transformation	MEA value of system assets £	Cost per kW of reference system £/kW	Capital charges based on 6.9% rate of return £/kW/annum	Tariff including cost uplift £/kW/annum	Cumulative charge £/kW/annum
GSP Connection	£9,642,296	£19.28	£1.43	£2.54	£2.54
132 kV cables and lines	£64,664,045	£129.33	£9.59	£17.03	£19.57
132/33 kV transformation	£10,630,973	£21.26	£1.58	£2.81	£22.37

33 kV cables and lines	£18,120,133	£36.24	£2.69	£4.77	£27.14
33/11 kV transformations	£9,917,234	£19.83	£1.47	£2.62	£29.75
Total system value	£112,974,679				

27. Under the DRM methodology load will incur charges that reflect those elements of the system at the voltage of connection and higher voltages. It is a characteristic of the reference network that charges seen by load connected at each EHV bus-bar will be broadly similar. Site specific charges for the large customer at bus-bars 2 and 7 are calculated according to the actual assets employed. One of these customers (bus-bar 2) requires relatively few assets so charges are lower than the DRM charges. The other has an expensive connection to the system, which results in charges being significantly higher than those seen by generic industrial load.

28. Charges for generation are determined from a different methodology. In line with the intermediate methodology applicable from 1 April 2005, a generator use of system charge (GDUoS) of £7.00/kW/annum for generation connected at EHV, and £7.67/kW/annum for connection at HV has been assumed. This is based on the anticipated cost of reinforcing a network to accommodate the distributed generation that it is expected will join the system. These figures are at the top end of the range of prices currently published for GDUoS but this is not anticipated to significantly impact the outcome of the analysis.

Economic Pricing Models

29. The economic pricing models take a different approach to the attribution of system costs to the user. All models start from an assessment of the marginal cost of adding an increment of demand or generation at each node on the system. Two approaches are then considered in deriving the marginal costs. In the first approach it is assumed that incremental demand (or generation) is met by uniformly expanding the network. This approach is referred to as the Investment Cost Related Pricing (ICRP) model. In the second approach the marginal cost is assessed from the change in the present value of the anticipated costs of reinforcing the network as a consequence of adding the increment. This approach is referred to as the Long Run Incremental Cost (LRIC) model. Both approaches are examined under DC and AC load flow studies.

30. In each case a fixed amount per kW is added to scale the revenues to meet the target revenue permitted under the price control. The issue of scaling is discussed further below. It is assumed for the purposes of this study that the target revenue will be the same under the economic charging models as that raised by the DRM.

ICRP Models

31. The ICRP methodology follows the same general approach as that employed by National Grid for transmission charging. It reflects the cost of meeting an increment of demand or generation at each node on the reference network. The cost is derived by applying a standard cost for the network to the "distance" power must flow to meet the increment of demand. This standard cost is known as the "expansion constant" and is expressed in £/kW/km. In the approach currently used for transmission pricing the expansion constant is not varied with voltage.

32. In applying the methodology to distribution this study has derived a different expansion constant for each circuit on the reference network rather than taking a network average. This is appropriate since the costs of the distribution system can vary widely with geography, and individual nodes have substantially different levels of connected load relative to the capacity of the system at that location. Expansion constants are expressed in £/kW/km or £/kVA/km depending upon whether the model is based on a DC or AC load flow analysis. The expansion constants have been calculated as an annual capital charge based on the MEA value of the assets together with the associated O&M.

33. ICRP derived marginal costs are expressed relative to a reference node; commonly referred to as the "slack node", where the marginal cost of connecting load or generation is zero. In its application to a distribution system the ICRP model will recognise all Grid Supply Points (GSP) as "slack nodes", since there is no distribution network cost from adding load or generation at these locations. Thus ICRP derived charges will always be relative to the GSP. This is consistent with the DRM approach.

34. As for the DRM, the ICRP model assumes a security factor of 2. This is also similar to the security factor adopted for transmission pricing. This implies that supplies given at EHV will require twice the circuit and transformer capacity to remain secure in the event of the loss of any circuit. However, unlike the modelling of the transmission

system a sub-station has been represented by two nodes in this model, one on the high voltage side of the sub-station, and the other on the low voltage side. This enables the sub-station and the associated transformers to be represented as a discrete asset between the higher and lower voltage nodes.

35. A characteristic of ICRP models is that the marginal cost derived for connecting generation or load at a node on the network will be the same absolute value but with one having the inverse sign of the other. The connection of generation will thus always produce a credit at demand dominated nodes, but a cost at generation dominated nodes. In the case of transmission charges this relationship is altered by a scaling rule that overall ensures 27% of use of system charges are borne by connected generation, and 73% by connected load. Given the tiny amount of generation connected to the distribution system such a rule would be inappropriate. In these studies the shortfall against the price control revenue is recovered solely from demand customers.

36. The ICRP methodology does not recognise the degree to which the existing assets are loaded. Instead it assumes that the network can be expanded linearly to accommodate all new demand and generation without the creation of any surplus capacity. This could be a significant weakness when ICRP is applied to distribution systems since the radial nature of the network makes individual investment decisions much more "lumpy" and circuit utilisations vary greatly as a consequence. .An advantage of this approach is that it is well understood within the industry, and when applied to distribution voltages may be viewed as creating consistency between the treatment of EHV and transmission networks.

ICRP application to reference network

37. When applied to the reference network the ICRP models produce charges for the EHV part of the network that have the potential to vary widely. For 33 kV nodes in close proximity to the transmission system, such as bus-bars 2 and 7 in the reference network, the marginally derived EHV charges are significantly less that those obtained from the DRM. However, for the more geographically distant bus-bars 9, 10 and 11, the marginally derived charges are significantly higher than the DRM charges. In the base year of study the DC version of the ICRP model recovered 39.3% of the permitted revenue from the marginally derived tariff rates.

38. On transmission systems it is possible to compensate for reactive power flows either from connected generation or by the installation of static compensation equipment. However, on distribution systems the reactive power requirements of the user may often lead to reinforcement of the system. Accordingly modelling the system on the basis of DC load flows will tend to understate the use that is made of the various assets, whereas an AC load flow study will better reflect the costs of the network in accommodating both active and reactive power flows.

39. The second ICRP pricing model considered employs the same approach to costs but now uses an AC load flow to determine the additional asset capacity that will be needed to meet an addition of load or generation at each node. Although it requires a more complicated load flow study and much larger data set it has the merit that it also addresses the network costs arising from poor power factor. Charges that reflect the marginal costs as determined from an AC load flow model recover a somewhat high proportion of the permitted revenue than is the cased for the DC model. For the reference network considered here the marginal rates recovered 43.0% of the target revenue in the base year of the study.

LRIC Models

40. The more common situation within a distribution system is that there is significant variability in the utilisation of its component assets, whereas this variation is not such a significant feature of the transmission network. The LRIC approach endeavours to recognise the existence of unused capacity on the network by assessing the additional cost that arises from the need to advance investment as a result of adding load or generation at any node on the system, or alternatively the reduction in cost that will result from delaying investment.

41. The study has therefore considered two new charging models where the cost of meeting incremental load or generation is based on the nature and timing of the impact on future network investment. The approach has been developed by the University of Bath in conjunction with Western Power Distribution. Using the same nodal framework as for the ICRP approach, the methodology looks at the present value of future investment both with and without the increment of load, and expresses the cost of meeting the increment as the difference between the two present values. It thus reflects the asset costs of meeting the increment, which for lines and cables will be a

function of distance as in the ICRP approach, but also the horizon when the new investment will be required. It is described mathematically in Annexe 1.

42. In common with the ICRP approach, the LRIC network model has been studied under both DC and AC power flow scenarios. As noted above DC power flows do not recognise the contribution reactive power flows make to the required capacity, whereas an AC power flow will recognise the system reinforcement that is consequent upon the reactive power requirements of both load and generation. LRIC derived costs will not be symmetrical for both generation and demand since the nature of the reinforcement could be significantly different in each case. For example whilst load may trigger reinforcement of the system, generation may contribute to fault levels and well as advancing future investment.

43. Bringing forward reinforcement costs through the addition of an increment of generation or demand that is a considerable time in the future may have very little associated cost. Since much of the network is relatively lightly utilised the revenues raised from the marginal charges derived under an LRIC approach recover a smaller proportion of the allowed revenue than is the case for ICRP. In the reference network considered here the revenue recovery from the marginal component of the tariff in the base year was just 15.2% of the allowed revenue under the DC load flow model, and 19.3% under the AC load flow study.

44. As a result when the same £/kW scaling algorithm is applied to produce the target revenue the variation in the charges at each node is substantially diminished compared to the ICRP approach. However, as system utilisation increases the nodal price should rise exponentially to reflect the impending need for system reinforcement.

Scaling to allowed revenues

45. In this study the addition of a supplement to the DRM asset costs has been used to produce the revenue permitted under a regulatory price control. However, for pricing models based on the costs of meeting incremental demand and generation the revenue recovered from the marginally determined charge is unlikely to meet fully the price control revenue target. This is because many assets will be underutilised or be stranded from prior investments. For cost models based on marginal costs it has been necessary to assume a mechanism for inflating (or deflating) charges to recover the permitted revenues under the adopted price control regime.

46. This raises the issue of whether Ramsey pricing principles would be appropriate as favoured in all the academic reports commissioned by Ofgem[2]. The merit of such an approach lies in preserving the efficacy of the economic cost and siting messages. On the other hand concerns have been raised regarding the equity of such an approach, and the impact it would have on the fuel poor. Furthermore adopting Ramsey pricing would require price elasticities to be justified, which given the paucity of data in this area could be difficult.

47. Generally these are matters for regulatory policy. For the charging models to produce internally consistent answers a scaling assumption has been applied to recover any shortfall in the target revenue for any particular model by a simple £/kW "postage stamp". This has been applied solely to the demand use of system prices.

Price comparison

48. The results derived from these models in the first year of the study period are compared in the diagrams below. The first diagram shows the marginal rates derived from the pricing model, and the second indicates the effect of the scaling assumption used to create the tariff rates. Prices at nodes labelled 1 – 11 are the rates chargeable to load, and prices at nodes 12 – 22 are the generation rates at the same demand nodes. The associated rates for these tariffs are given in Annexe 2.

49. For load, (shown as nodes 1 to 11) the DRM prices are relatively constant across all nodes, with only a slight variation reflecting the difference between load connected at 33 kV and that connected at 11 kV. The prices can be taken as the benchmark against which to compare the outputs from the economic models.

50. The marginal prices produced by the ICRP models for demand reflect the "distance" in terms of the cost of the assets, from the GSP and are thus most substantial for nodes 9, 10 and 11. For the industrial and some of the urban nodes the marginally derived prices are very low. However, once the scaling assumption is incorporated the rates at

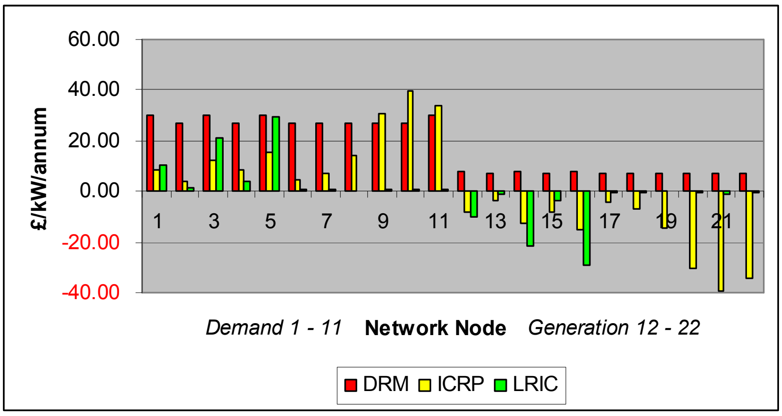
[2] Longer term framework for Electricity Distribution Access Charges, March 2005
- Tooraj Jamasb, Karsten Neuhoff, David Newbery and Michael Pollitt, University of Cambridge
- Ralph Turvey, Frontier Economics
- Goran Strbac and Dr Joseph Mutale; Centre for Distributed Generation and Sustainable Electrical Energy

nodes with low marginal costs become similar to the DRM output, and the rates for the more distant nodes are accentuated.

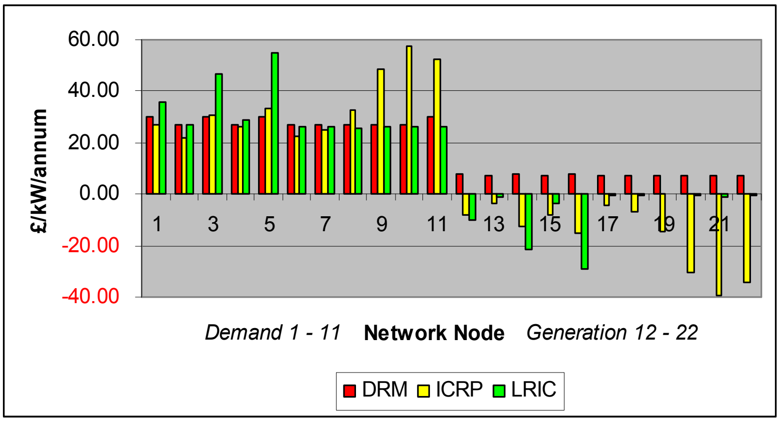
51. The output from the LRIC approach produces a very different locational message. In the rural area the marginal costs are very low. Because the revenue recovery from the marginal rates is also low the scaling factor is very substantial. This results in the rural nodes having scaled prices very similar to those produced from the DRM. In the urban area though the high utilisation of the network at nodes 1,3 and 5 produces much higher charges than is the case for either the DRM or ICRP methodologies.

52. For generation, where no scaling has been applied, the ICRP methodology mirrors the distance effect for the rural nodes by producing substantially negative charges (credits) for generation. This should attract generation to the more rural area. Under the LRIC approach generation would find it most attractive to connect to nodes 3 and 5, which are in the urban area. (These are shown as 14 and 16 in the diagram below).

Marginal component of DC tariff variants of economic models compared to DRM



2005 Tariff Rates for the DRM and DC variants of economic models



CUSTOMER RESPONSE MODELS

General assumption

53. In considering the possible customer response to the prices produced by different charging models we have looked separately at the general classes of load connected at LV and HV, but which make use of the EHV network, and load and generation connected directly to the EHV network. For customer demand connected at LV and HV we have assumed that the growth of load at existing sites will react to price according to generic customer class price elasticities. The assumed elasticities are taken to cause differential rates of growth in the load connected at each bus-bar location on the reference network.

54. For the growth in generation and demand connecting at EHV a somewhat different approach is adopted. EHV connected industrial load is assumed to be more price elastic than that connected at lower voltages, but its growth is assumed to be characterised as new large customers that site in an economically rational manner. That is they are taken to join the network at the location that has the lowest price at the time the connection is made.

55. A similar approach in the customer response model is taken in respect of the growth in distributed generation. Distributed generation is expected to grow at a rate that reflects Government targets and the overall demand served by the reference network. However, the distributed generation is also assumed to behave in an economically rational manner and connect at a location that maximises the rate of return that any particular generation project can earn.

Demand response models

56. The change in customer demand consequent upon a change in price can be established by the application of appropriate price elasticities. The demand for electricity, as for other commodities, can be expected to decrease as price rises and vice versa. However, the demand curve is invariably difficult, if not impossible to quantify. Accordingly any consideration of the responsiveness of demand to price invariably expresses the curve as a linear function at a point on the demand curve, and then defines the price elasticity of demand as the ratio of the percentage change in the

quantity consumed and the percentage change in price; all other factors remaining equal. The equation usually employed for expressing price elasticity is thus:

$$E_p = \frac{\text{\% change in Quantity}}{\text{\% change in Price}}$$

57. Although the concept of price elasticity is widely discussed in academic literature there is a paucity of studies that provide a quantification of the ratio for the UK, or for most other developed economies. A distinction has to be drawn between short run and long run price elasticity. The nature of electricity demand suggests that in the short term electricity demand shows very little response to movements in price. Studies therefore tend to focus on long run movements in demand following changes in price.

58. A series of Swiss studies suggest that electricity demand has become significantly less responsive to price over time. It also appears that there is considerable uncertainty in the precision with which the results of any study are expressed. An investigation of residential electricity consumption that looked at data between 1964 and 1990 suggested residential price elasticities that ranged from -0.5 to -0.7. However, in a more recent study[3] in Switzerland (1999) the price elasticity was reckoned to have reduced to -0.3.

59. As an assumption for this project we have adopted the price elasticities recommended by the Australian National Institute of Economic Research (NIESR) in 2004[4]. These relate to an economy that is not dissimilar to that in the UK. Their advice drew on their 1999 study and a review of overseas studies. NIESR's recommended long run price elasticities for each of the customer sectors are:

Residential	-0.25
Commercial	-0.35
Industrial	-0.38

60. These long run elasticities operate on the price seen by the customer. Thus the impact of a change in the component of the price relating to the EHV distribution system as a result of changing the charging methodology will be diluted by the other components of the overall price when determining the overall change in demand.

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[3] Filippini, M., 1999, Swiss residential demand for electricity, Applied economic letters, Centre for Energy Policy and Economics, ETH Zurich

[4] The price elasticity of demand for electricity in NEM regions, National Electricity Market Management Company, June 2004

Arithmetically the “dilution factor” can be derived from the proportion that the EHV network component comprises of the final price seen by the customer.

Diluted price elasticity factors for HV and LV customers as a consequence of changes in EHV network charges

	Residential	**Industrial**	**Commercial**
Final electricity price p/kWh	8.0	4.0	6.0
EHV Distribution system price	0.5	0.3	0.4
% dilution of price elasticity	6.25%	7.5%	6.7%
“Diluted” price elasticity	-0.0156	-0.0285	-0.235

61. The change in the electricity demand of each of the generic classes of industrial, commercial and residential connected at LV and HV as a result of a change in EHV network prices thus follow the diluted price elasticities derived above. The small value of these price elasticities means that little differential response can be expected from these customer groups as a result of applying each of the pricing approaches.

62. However, the growth in industrial load connected at EHV is assumed to be more responsive to price than the general body of industrial customers connected at lower voltages and display a long run elasticity of -0.5. As noted above the growth in EHV connected industrial load is assumed to manifest itself as the arrival of new large customers over the study period. In behaving in an economically rational manner these new customers are assumed to connect at the bus-bar demonstrating the lowest use of system charges at the time of connection.

Generation response model

63. The amount of new GB renewable generation constructed each year is assumed to be sufficient to produce that proportion of energy required to meet the Government’s target. The assumption is made that 60% of this generation will connect to the transmission system and 40% to the distribution networks. Distributed generation is in turn assumed to comprise 20% CHP and 80% wind farms. CHP generation is taken to have a load factor of 80%, whilst wind generation displays a 30% load factor. The economic life of both forms of distributed generation is taken to be 20 years.

64. Distributed generation connecting to the reference network is taken to display the same proportions of the energy flowing across the network as the national averages indicated in the above assumptions. Thus the output of this generation will be a function of the load growth, which is consequent upon the demand response to the charges produced from each pricing model.

65. In deciding the location at which the new distributed generation will site on the reference network an investment model is employed that reflects the cash flow of each generation project. The model incorporates the capital cost, operation and maintenance costs, connection costs, EHV distribution network charges and, in the case of CHP, the anticipated fuel cost.

66. For wind generation, the AC models provide a choice of three operating power factors depending upon the nodal prices calculated for the provision of reactive power. If the price of reactive power is less than the cost of providing local compensation then the model will assume that there is no need for the wind generator to install reactive compensation and instead absorb reactive power from the network. However, if the price of reactive is such that local compensation is economic, then the model will install local compensation and the generator will either inject reactive power to the network or operate at a unity power factor depending upon the requirement of network.

67. Generators are deemed to site at the network location that will give the most favourable rate of return as viewed at the time of connection. It is assumed that there will be sufficient price support for this technology in any year such that the requisite volume of generation needed to match government targets will attain the hurdle rate of return of 15% in the investment model for the project to be implemented.

User behaviour under different pricing models

68. The response of network users to the pricing signals produced by the various charging models is considered over a 20 year period, with "snapshots" taken at five yearly intervals. Although the price elasticities are long run, the reflection of these in the ICRP and LRIC models is to produce a step change in the first year of the period as the pricing relativities adjust to reflect the characteristics of the model. In practice changes in demand would be expected to occur more gradually, although the relatively small impact of the price elasticities on generic customer demand and the 5 year intervals in the analysis means that this simplification does not have any significant

materiality since the major consequences are not apparent until the latter part of the study period.

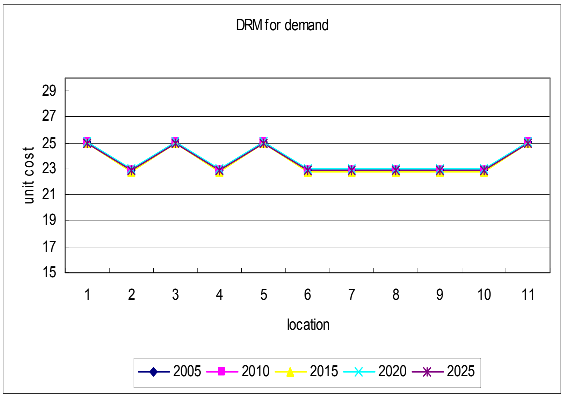
69. The impact of each of the five charging models on user behaviour has been considered in turn. These are described below. The consequence for system investment of these various responses is assessed in the next section of the report.

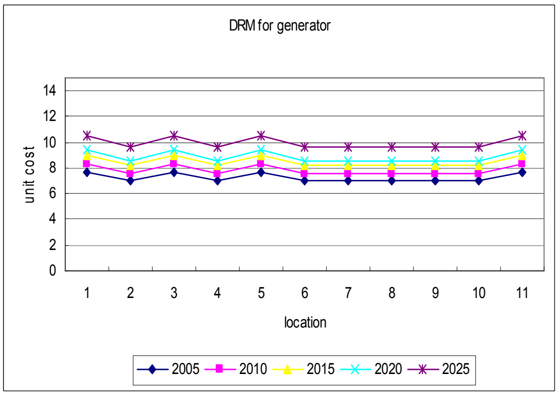
Customer response to the DRM

70. The yardstick construction of the DRM means that prices are the same at each voltage level for all geographic locations. The dilution in the price elasticity effect for LV and HV connected load means there is no perceptible response from this demand. Annual demand growth is taken to accord with the underlying trend of 1.6% per annum. The only perturbation to the model is caused by the siting of new large industrial load, which is assumed to connect at bus-bar 6, since this is within an industrial area.

71. In the case of the DRM where there is no locational signal in the price the model assumes that the generation will locate at a site that is most appropriate for the type of generation. Thus for wind generation it is assumed that the higher wind speeds associated with the terrain around location 8 will make those the obvious locations, and the industrial network at location 6 will be the obvious point of connection for CHP generation.

72. The approach to deriving generator use of system charges as an adjunct to the DRM is to base charges on the anticipated cost of the investment required to accommodate the expected quantum of generation that will connect to the network. Because the GDUoS charges always contribute to the distributor's overall revenue, the revenue recovery required from demand customers reduces slightly towards the end of the period as the overall target revenue is met. This assumes that revenue from generation and demand charges are subject to the same price control although this is not the case in the current price control period. A similar effect occurs as the result of the connection of site specific loads where the asset specific charges are higher than the tariff produced by the DRM and thus require less revenue to be raisd from tariff customers.





DRM demand prices *DRM generation prices*

73. Under the DRM the overall growth in demand from all types of load over the 20 year study period was 113.6 MW of which 18 MW was attributable to large loads connecting at EHV. A total of 19.7 MW of distributed generation also connected in this period.

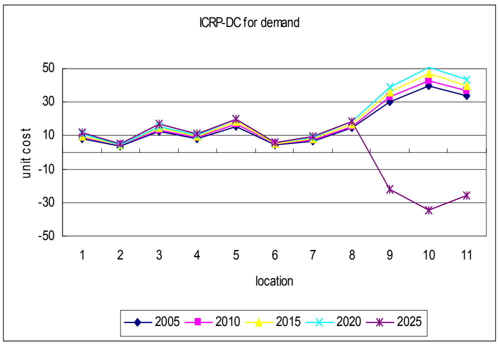
Customer response to ICRP (DC power flow)

74. Prices derived from the ICRP model reflect the distance that power must travel to find load. Unlike the output from the DRM, prices produced by the ICRP-DC model vary between nodes depending upon the extent of the assets at each node. Initially all demand pays for use of the network, albeit in differing amounts depending upon the extensiveness of the local network, and generation is rewarded for offsetting the demand power flows.

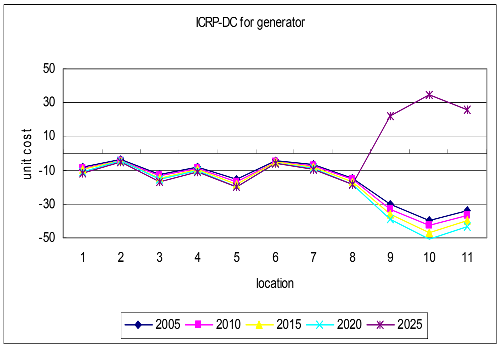
75. Generation is initially attracted to the distant nodes 9,10 and 11 because of the high credits created by the ICRP model, but charges for demand at these nodes remain high thus discouraging load growth. Instead demand tends to grow fastest at nodes 1 and 2 (urban area) where the distances from the GSP are least, and prices are thus lowest. However, eventually sufficient generation locates at these distant nodes to cause power flows to reverse with the generation exporting from the GSP. At this point the charges paid by generators become positive and demand is rewarded for offsetting the export. This in turn stimulates large EHV connecting industrial load to site at location 9 in the latter part of the study until the power flow eventually reverses again.

76. The effect is dramatically illustrated in the following diagrams of price evolution over the study period. These show that the ICRP methodology gives rise to a pricing

instability at distant nodes where there is relatively little load connected. More heavily loaded nodes which have relatively short distances to the GSP display a more stable pricing signal under the model. It should be noted that under the ICRP approach the expansion constants reflect only the cost of expanding the system to accommodate the increased amount of generation and do not take account of fault level considerations.



ICRP-DC Demand charges



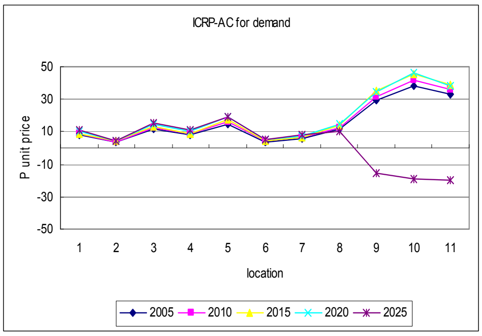
ICRP-DC Generation charges

77. Under this pricing model the overall growth in demand is 111.1 MW of which 19 MW is associated with large industrial customers connecting at EHV.

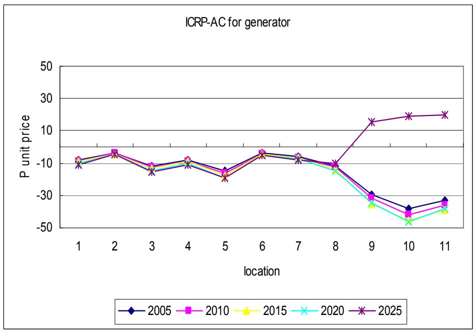
Customer response to ICRP (AC power flow)

78. The ICRP pricing model based on an AC power flow analysis shows a similar pattern of price development to the DC based model until 2010. Generally generation is attracted to nodes 10 and 11, which have substantially negative generation charges. Because the analysis always assumes that wind generation absorbs reactive power in the production of active power it results in the outcome of high reactive power charges associated with relatively low real power charges. This seems an unlikely combination but the overall cost for generation at these nodes is higher towards the end of the study period as a result of the reactive charges.

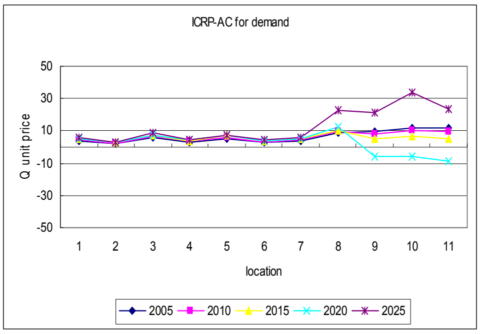
79. In reality it is likely that the generator owner would install reactive compensation to reduce the high cost burden that would otherwise emerge. This, of course, is the merit of the AC charging model in that it would encourage a response that might not otherwise be apparent if the DC load flow variant of the charging model were employed.



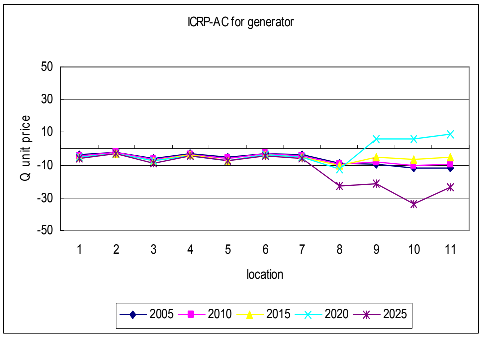
ICRP-AC MW Demand charges.



ICRP-AC MW Generation charges



ICRP-AC Demand reactive power charges



ICRP-AC Generation reactive power charges

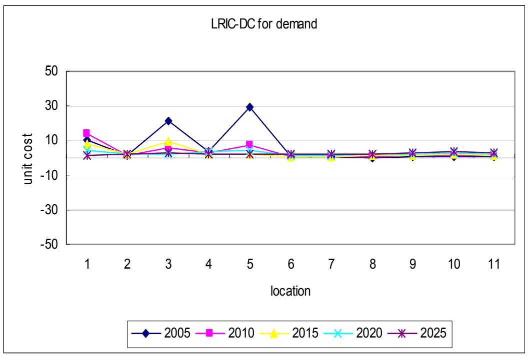
80. The resultant load growth from the employment of the ICRP-AC pricing model is significantly different to that for the DC variant. Although the active power charges at node 2 are the lowest of any location in 2005, large industrial demand prefers to site at node 6 due to the negligible reactive power charges at this location. This increases the reactive power charges at node 6 and by 2015 node 2 becomes the favoured choice for the siting of large industrial loads. In 2020 node 9 becomes dominated by generation and the reversal of the power flow results in credits for demand locating at this location. This is a portent for the instability in charging that was observed in the ICRP-DC pricing model. The overall demand growth over the 20 year study period under this pricing approach is 113.5 MW of which 19 MW is attributable to large industrial customers.

81. As for the ICRP-DC model generation is attracted to nodes 9, 10 and 11 where the distance of the locations from the GSP gives rise to significant credits for most of the study period. The reversal of the power flows at node 9 is the exception to this generality. Although generator charges are the mirror image of demand charges, this is not the case for reactive power charges as the diagrams above demonstrate.

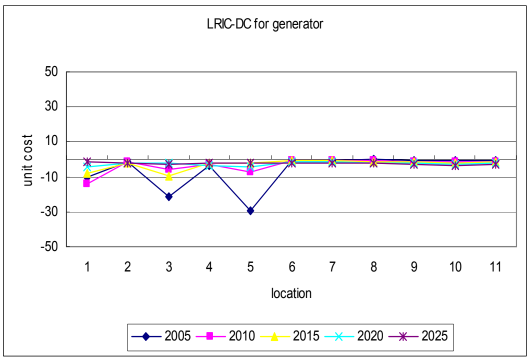
Customer response to LRIC (DC power flow)

82. The LRIC-DC model produced a locational pattern of prices that is strikingly different to that produced by the ICRP models. Nodal prices are now driven by not only the distance the load or generation is from the GSP but also the utilisation of those assets. As a consequence demand prices and generation credits for some of the urban nodes tend to be relatively high, whilst the lightly loaded parts of the network in the rural area display relatively low prices. The LRIC models create a dynamic interaction with network users over the study years that produces a more efficient network. Charges at all nodes converge over the period as demand and generation are attracted to locations where they can make optimal use of the network. In time an equilibrium should be created between the cost of the assets at a node and the utilisation of those assets.

83. Unlike the output from the ICRP models, prices derived for generation from the LRIC models are not an exact mirror image of the prices for demand. This is because the cost of advancing system reinforcement will not be the same as the savings from delaying investment in the network. Although the analysis undertaken for this study has not taken account of the price effects created by network costs incurred as a result of increased fault levels from the connection of new generation, the LRIC model does have the capacity to do this. This would lead to yet further asymmetry between prices for demand and generation derived from this model.



LRIC-DC Demand charges



LRIC-DC Generation charges

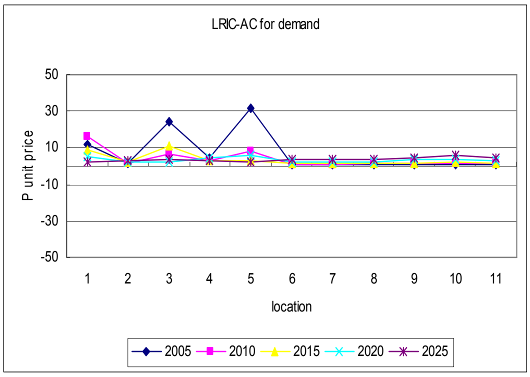
84. Applying the prices derived from the LRIC-DC model to the customer behaviour model resulted in industrial load growing initially at node 8 which is both lightly loaded and has fewer assets compared with the rest of the rural network. As node 8 becomes more heavily loaded, the preferred location for new EHV connecting industrial load becomes node 6 in the industrial area. Over the study period the overall demand

growth under this pricing regime was 111.1 MW of which 19 MW was attributable to large industrial load.

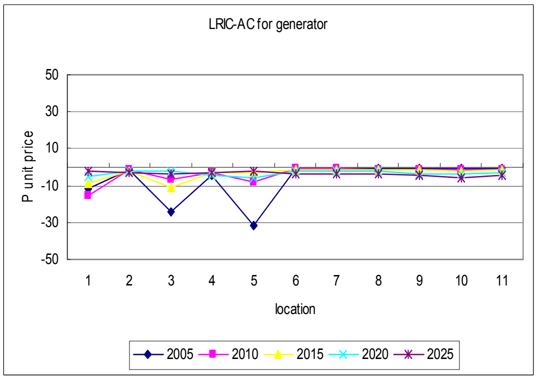
85. In the case of the LRIC-DC model generation is attracted exclusively to the highly loaded nodes 1, 3, and 5 in the urban area. This is principally because the high utilisation of the transformers at these nodes provides a strong siting signal that attracts generation. This has a significant benefit for the system in that the arrival of the generation delays reinforcement that would otherwise be needed.

Customer response to LRIC (AC power flow)

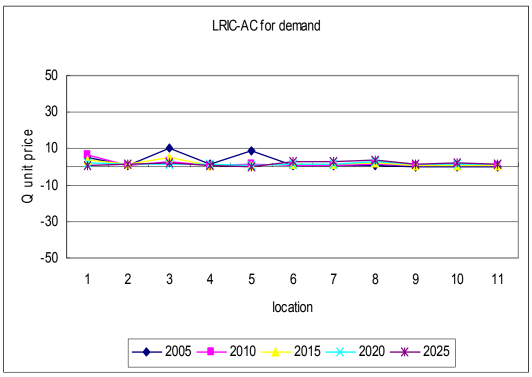
86. Prices produced by the LRIC model are generally accentuated under AC power flows when compared to the operation of the model in the context of DC power flows. This is because the capacity in the system is utilised more rapidly in order to accommodate the reactive power flows.



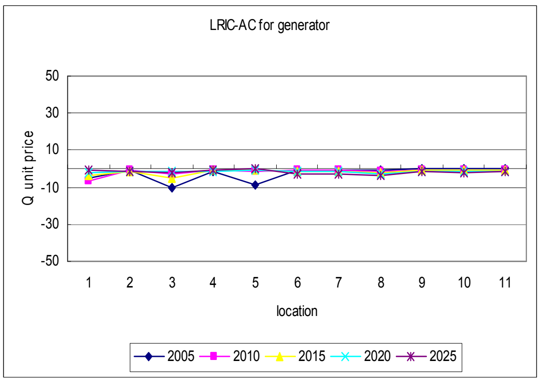
LRIC-AC kW prices for demand



LRIC-AC kW prices for generation



LRIC-AC kVAr prices for demand



LRIC-AC kVAr prices for generation

87. Compared to the LRIC-DC model, the AC version produced prices that demand found most favourable initially at node 6, and then at nodes 11 and 8 before returning to node 6 as the preferred location at the end of the study period. Thus the pricing signal

from this approach causes EHV connecting industrial load to locate on those parts of the system that are most lightly loaded. The overall growth of demand under this model was 111.1 MW of which 19 MW was large industrial demand; the same as for the DC variant.

88. The growth of distributed generation follows the same pattern as for the LRIC-DC model. Generation is attracted to the urban area and in particular nodes 1, 3 and 5 where it can provide most support for the existing system. There is no connection of generation to the distant rural nodes during the study period.

5 NETWORK INVESTMENT

General approach

89. The investment model that has been devised examines how the reinforcement requirements for the reference network necessary to maintain the required security and quality standards will change as load and generation materialises at different locations in response to each of the pricing models. The position is considered at 5 yearly intervals assuming that the new pricing regimes were implemented from 2005. The study period again extends to 2025.

90. The connection of distributed generation has the potential to impact the network in terms of its voltage levels and fault current levels. Although the pricing models did not take account of the price effects of changes to fault levels the investment model does increase the rating of equipment where an increase in the fault level requires this. There are a substantial number of investment options available to resolve the voltage and fault current problems that would be encountered in the connection of distributed generation[5]. These include network splitting, increasing generator impedance, installing current limiters and voltage compensation devices, and reinforcement of the network. Invariably the least cost solution at any point on the system will depend upon local considerations and be site specific.

91. In order to construct a workable investment model relatively simple rules have been adopted that simulate the investment likely to be needed as a consequence of the growth in demand and distributed generation. These rules are responsive to the loading of the various components of the reference network caused by the pattern of demand and generation that results from the customer response to the charging models. The performance of the system at the end of each five yearly period is analysed by the use of an AC power flow model and compared to the rating of the extant distribution assets.

92. The consequence of demand growth is contemplated in terms of the voltage at each bus-bar, and the thermal loading of circuits and transformers. The model installs SVCs to correct any under-voltage situation that may emerge from the load flow analysis. In

[5] The contribution of distribution network fault levels from the connection of distributed generation; DTI report, 2005.

the event that the current in circuits and transformers exceed their thermal rating then the model employs the next standard size of overhead line, cable or transformer.

93. In the case of new distributed generation the consequence for voltage at each bus-bar is again considered together with the impact on system fault levels. If voltages exceed the statutory limits then the model again installs SVCs to compensate the distribution network. If fault levels exceed the fault current rating of switchgear then the model replaces the switchgear with the next higher standard fault current rating. In the event that the highest rating of switchgear is already in use then the model will install fault current limiters to enable the network to be compliant with its design standard.

Network investment under different pricing models

94. We have demonstrated above how the different pricing models influence the location and to a lesser extent the amount, of future generation and load differently, the network investment required to maintain security and quality of electricity supplies will also differ significantly for each of the pricing approaches. The economic efficiency of each pricing approach can thus be assessed by applying the investment model described above to determine the quantum of capital expenditure required to accommodate the new load and generation under each pricing methodology.

95. The capital expenditure needed to accommodate new demand and generation has been calculated in each year of the study period and then discounted back to its present value. Since the amount of new load and generation connecting is broadly similar under each pricing scenario it is sufficient to consider only the total expenditure required over the 20-year study period. The table below summarises the output from the investment model in terms of the present value of the investment needed over the study period under each of the pricing models.

Present value of network reinforcement cost for each pricing model up to 2025

Pricing Model	Due to demand (£)	Due to generation (£)	Total (£)
DRM	564,945	439,099	1,004,044
ICRP_DC	431,582	398,598	830,180
ICRP_AC	431,582	202,358	633,940
LRIC_DC	0	367,966	367,966
LRIC_AC	0	171,725	171,725

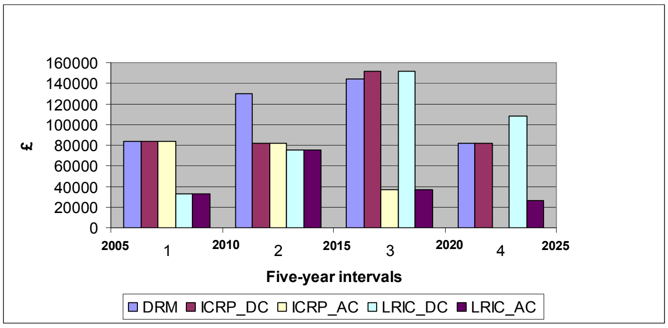
Generation related investment

96. Distributed generation is not a part of the DRM pricing model and there is no locational signal for the siting of generation under this approach. However, the assumption is that generation would site rationally and thus there is a concentration of generation investment at just two locations. CHP generation is taken to site at bus-bar 6 which is the lowest cost location in the industrial part of the network, and wind generation is taken to site at bus-bar 8 which is the lowest cost location on the rural network. The output from the investment model shows that the highest system cost for accommodating generation and demand is associated with this pricing methodology. This is not particularly surprising since the DRM pricing model has no locational signal to which generation can respond.

97. As we have seen under the ICRP models the generation would tend to concentrate at the most distant nodes since these present the best credits for generation. However, these locations are also characterised by substantial network assets. Because of this the ICRP approach gives rise to the need for substantial investment to accommodate the increase in fault level. The attractiveness of these nodes in terms of price only ceases when the quantum of new generation causes the power flow at the node to reverse. As has already been noted this may be seen a significant weakness of the application of the ICRP approach to distribution systems.

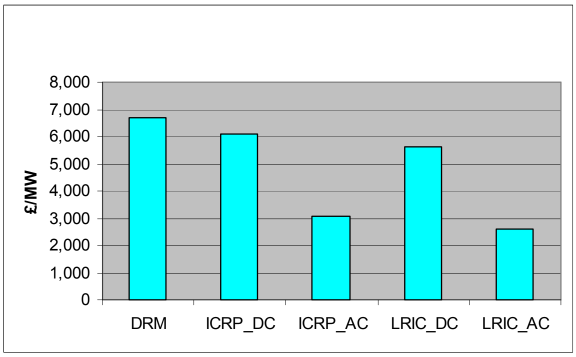
98. The LRIC models also caused significant network investment to upgrade switchgear for increased fault levels. However, this model has a major advantage in that because the pricing incentive is to site where assets are most heavily loaded there is no investment needed to accommodate the growth in demand. Effectively the addition of generation at the chosen locations is offsetting the need to reinforce the system for the growth in demand. .

Present value of network investment required for new generation



99. When considered cumulatively over the study period the AC power flow models produced significantly lower investment costs than their DC counterparts, and the LRIC-AC model slightly outperforms the ICRP-AC model. The merit of the AC pricing model variant is that it can reflect the requirements of the network for reactive power. As was noted earlier, in the investment model the wind generator has a choice of operating at one of three power factors. Depending upon the level of the reactive power charge the generator exercises an economic choice between installing reactive compensation equipment and relying on the network to provide the reactive power.

Present value, in £/MW, of cumulative network investment cost for new generation under different pricing models

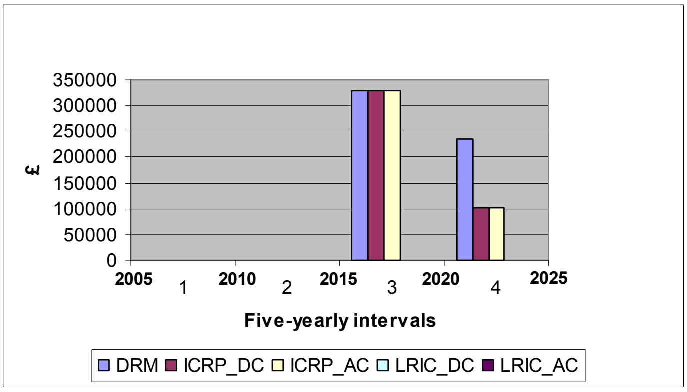


Demand related investment under different pricing models

100. The principal investment cost resulting from the addition of new load was due to the need to increase transformer capacity and reinforce circuits as a result of thermal limitations and under-voltages. Because the LRIC models encouraged generation to locate at the most heavily loaded nodes this had the effect of obviating the need to reinforce the system at these locations for the growth of demand. The reinforcement cost for demand under this pricing model was therefore zero.

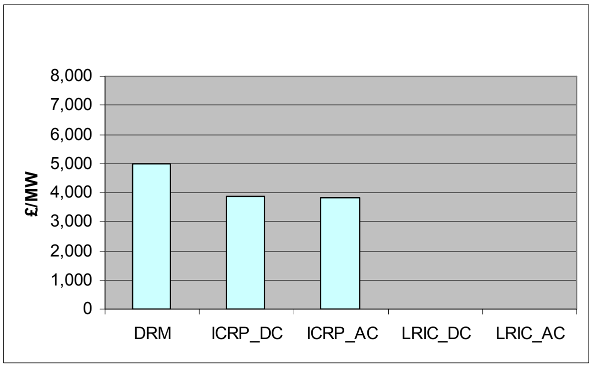
101. The perverse signals in the ICRP models that encourage load to site at nodes that have the least distance from the associated GSP without reference to the utilisation of the associated assets, which in the reference network are the most heavily loaded circuits and transformers, causes these models to require the most investment for the connection of incremental load. The diagram below shows the progression of investment needed under each pricing approach over the study period.

Present value of network investment required for new load



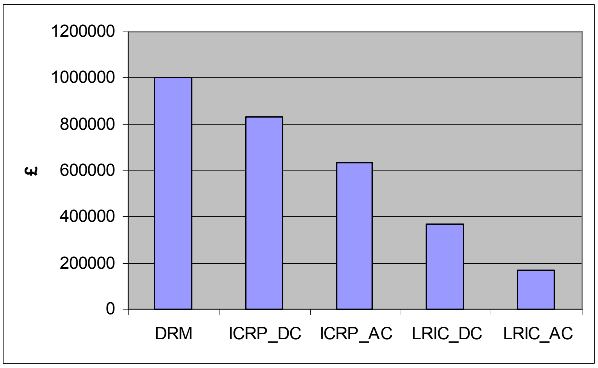
102. Over the 20 year study period the DRM methodology requires the greatest amount of cumulative network investment of any of the pricing models to accommodate new load. Since reactive power charge did not play a part in the modelling of demand response to the locational pricing signals the investment model has calculated the same investment cost for both the DC and AC variants of the ICRP pricing approach. .However, as noted above the LRIC approach substantially outperforms both the DRM and ICRP approaches since it does not require any investment to meet the forecast growth in demand provided new generation locates in an economically rational manner.

Present value, in £/MW, of cumulative network investment cost for meeting new load under different pricing models



103. When the investment cost of meeting new load and generation are taken together the ICRP methodologies generally outperform the DRM approach in the amount of investment that is required to reinforce the network. However, the LRIC charging methodologies demonstrate by far the lowest investment cost of the pricing approaches considered here, with the LRIC-AC approach producing the best result.

Present value of overall investment needed to accommodate new load and generation over the 20-year study period



6 CONCLUSIONS AND OBSERVATIONS

General conclusions

104. The aim of this study has been to simulate the impact a new regime for deriving distribution charges might have on the long-term investment costs of developing the distribution network. In undertaking this analysis the study has assumed that the network development must take account of both a growth in distributed generation as well as a growth in demand.

105. The approach has been to explore the extent to which different charging methodologies would be likely to influence customer behaviour in terms of the magnitude and location of new load and generation that would appear over a 20-year study period. Price elasticity effects seem to have a relatively small impact on load growth, but siting decisions of load connecting at EHV could be significantly affected by the choice of pricing approach. The cost of expanding and reinforcing a reference network to accommodate the customer response has then been taken as a measure of the efficiency of the each pricing methodology.

106. This study has considered five pricing methodologies, albeit two of these were the AC variant of the associated DC methodology. The conventional DRM charging methodology has been used as the benchmark against which the other models based on economic principles could be assessed. The results demonstrate that for the chosen reference network there would be a significantly lower cost to reinforcing the network if the economic charging approaches were adopted in place of the conventional DRM. The fundamental reason for this is simply that the economic charging models provide a pricing signal for the more efficient siting of load and generation that is absent in the DRM. However by considering two different forms of economic charging model it is also apparent that the nature of the pricing signal can produce quite different future investment programmes.

107. Over the study period the most effective pricing approach showed a reduction in the present value of the cost of reinforcing the EHV reference network, which served 275 MW of load and 10 MW of generation in the base year, of £830k. If this were extrapolated across the GB system is it would imply a cost saving in the region of £200 million. Of course such an extrapolation would have little foundation since the

reference network is not necessarily typical of the extant distribution systems. However, it does indicate the magnitude of potential saving that might be available over this timescale.

Other observations

108. The study has produced a number of interesting insights into how different charging models are likely to influence network users. The ICRP approach that is used for transmission pricing might have some attractions on grounds of consistency if applied to the EHV distribution network; especially since 132 kV is a transmission voltage in Scotland. However, when applied to the reference network it demonstrated that under certain circumstances it could provide perverse signals for the location of generation and load. It may also lead to unstable charges that “flip flop” between debit and credit for load and generation respectively where the location is relatively distant from the GSP.

109. Of the two economic approaches considered in the study, the LRIC approach would appear to have the most merit in that it reflects both the cost of the assets required to transport power to a node and the utilisation of those assets. The latter aspect is particularly relevant to distribution systems that are predominantly radial and do not have the degree of meshing found on the transmission system. There are a number of ways in which the LRIC approach can be interpreted. In this version the pricing message has been somewhat damped by expressing asset costs on a per unit basis. This may somewhat understate the benefits that could emerge from the pricing methodology.

Future investigations

110. A considerable number of assumptions and simplifications have been made in undertaking this study. Consequently a certain degree of caution is needed when contemplating how the conclusions that have been drawn should be applied. Further investigation of these assumptions and simplifications may be appropriate before any firm decisions are made on the way forward.

111. First, the reference network is extremely limited in that it addresses only the EHV system with some 33/11 kV transformations. The charging models have examined the impact of the methodologies on only the EHV component of the distribution use of

system charge. It has been seen that this has little impact on customers connected at lower voltages. The consequence of extending the charging methodologies to the HV network where a significantly larger body of customers are connected would be worthy of study.

112. In this context it may also be appropriate to investigate the role played by the HV network in providing security for the EHV network. The security criteria applied to the EHV system has assumed an implicit security factor of 2. That is there is a duplication of lines and transformers such that supplies can be maintained under fault conditions. However, the HV network frequently provides security for the EHV network which enables less EHV assets to be employed. The prevalence of this phenomena would tend to change the nature of the investment needed to accommodate growth in demand and distributed generation..

113. Although the reference network has been based upon a real network it is not representative of many parts of the GB system. Furthermore many network components such as protection devices and voltage support devices were excluded from the analysis. Before any extrapolation was made the analysis might also be applied to other typical networks.

114. The scaling assumption that recovers the non-marginal revenue in order to deliver the price control revenue target has a significant effect on price relativities and thus customer behaviour. It would be appropriate to investigate whether other scaling algorithms would produce widely differing investment results.

115. As a simplification we have not included the fault level consequence for price in the LRIC model even though it has this capability. This has probably resulted in overestimating the network development costs associated with this charging approach, and thus understating its economic efficiency. It would be helpful to assess the consequence of extending the pricing effects to include this aspect.

116. As noted above the LRIC approach can be interpreted in a number of ways. The significance for the customer behaviour and investment model outputs of different interpretations would inform the decision on whether it would be appropriate to introduce a degree of damping into the price signal, and how this might be best achieved.

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ANNEXE 1

Mathematical representation of LRIC Model

The unused capacity or headroom of an electrical component can be used to gauge the time before investment in network reinforcement is required. The greater the head room the further into the future before investment will be required. The more investment can be delayed, the lower the present value of the eventual cost. For any given rate of load growth, the time horizon for the future investment will be the time taken for the loading of a network component to grow to its maximum rated capacity.

The Long-run incremental cost pricing (LRIC) methodology seeks to reflect the impact on the advancement or deferral of future investment in network components as a result of a 1MW injection or withdrawal of generation or load at each study node. For component that is affected there will be a cost associated with accelerating investment, or a benefit associated with the deferral of investment. Depending upon the discount rate that is employed, and the magnitude of the expenditure, which could be a function transformer capacity or circuit length, the long-run incremental cost can be calculated.

The steps in the methodology are as follows:

1). Determine when investment will occur in the future

If a network component *l* has a capacity of C_l, supporting a power flow of D_l, then the number of years it takes to grow from D_l to C_l for a given load growth rate *r* can be determined through equation (1)

$$C_l = D_l \times (1+r)^{n_l} \qquad (1)$$

where *n* is the number of years taking D_l to C_l.

Take logarithm of both sides of equation (1) leads to:

$$n_l \times \log(1+r) = \log C_l - \log D_l \qquad (2)$$

Rearrange equation (2) gives the value of n:

$$n_l = \frac{\log C_l - \log D_l}{\log(1+r)} \quad (3)$$

Assuming investment will occur when the component is fully utilised, i.e. investment will occur in *n* years when its utilisation reaches C. Here a duplication of the component is assumed to be the future investment.

2). Determine the present value of future investment

This future investment can be discounted back to present value according to how far into the future investment will occur. If a discount rate of *d* is chosen, then the present value of future investment in n_l years will be:

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}} \quad (4)$$

where Asset is the duplicated asset cost, if the circuit is long in length, then future investment will be high, if the circuit is short, then potential investment will be low.

3). Determine the circuit's unit incremental cost

If the circuit is to support a capacity of C, then the cost to support a 1 MW flow will be:

$$U_l = \frac{PV_l}{C_l} = \frac{Asset_l}{C_l \times (1+d)^{n_l}} \quad (5)$$

4). Cost associated with 1MW increment

If the power flow change along line l is ΔP_l as a result of 1MW injection, which in turn brought forward future investment from year n_l to year $n_{l\,new}$:

$$C_l = (D_l + \Delta P_l) \times (1+r)^{n_{l\,new}} \quad (6)$$

Equation (6) will lead to the new investment horizon $n_{l\,new}$ to become:

$$n_{l\,new} = \frac{\log C_l - \log(D_l + \Delta P_l)}{\log(1+r)} \qquad (7)$$

This in turn affects the present value of the investment, hence the unit increment cost.

$$U_{l\,new} = \frac{PV_{l\,new}}{C_l} = \frac{Asset_l}{C_l \times (1+d)^{n_{l\,new}}} \qquad (8)$$

The additional unit cost incurred as a result of investment brought forward by 1MW injection will be the circuit long-run incremental cost to support 1MW power flow, given by equation (9):

$$\Delta U_l = U_{l\,new} - U_l = \frac{Asset_l}{C_l} \times \left(\frac{1}{(1+d)^{n_{l\,new}}} - \frac{1}{(1+d)^{n_l}}\right) \qquad (9)$$

5). Long-run incremental cost

Long-run incremental cost will be given by:

$$LRIC_N = \frac{\sum_l \Delta U_l}{\Delta P_{In}} \qquad (10)$$

where

ΔU_l is the change in unit cost as a result of 1MW injection, given by equation (9)

ΔP_{In} is the power injection at node *N*, here we have assumed 1MW

ANNEXE 2A

Annual marginal component of price derived from different charging models in 2005

**AC versions of the model also have reactive power charges*

Bus	Voltage	Connected	DRM	ICRP Models		LRIC Models	
				DC	AC	DC	AC
Bar		Party	£/kW	£/kW	£/kW*	£/kW	£/kW*
1	11	Demand	29.75	8.40	7.87	10.25	11.77
2	33	Demand	27.14	3.84	3.52	1.35	1.66
3	11	Demand	29.75	12.37	11.57	21.31	24.61
4	33	Demand	27.14	8.27	7.88	3.89	4.08
5	11	Demand	29.75	15.39	14.83	29.52	31.63
6	33	Demand	27.14	4.47	3.89	0.53	0.73
7	33	Demand	27.14	6.84	5.98	0.59	0.81
8	33	Demand	27.14	14.43	11.80	0.18	0.44
9	33	Demand	27.14	30.41	29.22	0.77	0.83
10	33	Demand	27.14	39.56	38.16	1.01	1.09
11	11	Demand	29.75	34.19	32.93	0.78	0.82
1	11	Generator	7.50	-8.40	-7.87	-10.24	-11.78
2	33	Generator	7.00	-3.84	-3.52	-1.35	-1.66
3	11	Generator	7.50	-12.37	-11.57	-21.26	-24.56
4	33	Generator	7.00	-8.28	-7.88	-3.69	-4.08
5	11	Generator	7.50	-15.39	-14.83	-29.46	-31.57
6	33	Generator	7.00	-4.47	-3.89	-0.53	-0.73
7	33	Generator	7.00	-6.84	-5.98	-0.59	-0.81
8	33	Generator	7.00	-14.43	-11.80	-0.18	-0.44
9	33	Generator	7.00	-30.41	-29.22	-0.77	-0.83
10	33	Generator	7.00	-39.57	-38.18	-1.01	-1.08
11	11	Generator	7.50	-30.42	-32.93	-0.76	-0.82
% price control recovered by marginal charges			**100%**	**39.3%**	**43.0%**	**15.2%**	**19.3%**

ANNEXE 2B

Annual prices (after scaling) derived from different charging models in 2005

**AC versions of the model also have reactive power charges*

Bus	Voltage	Connected	DRM	ICRP Models		LRIC Models	
				DC	AC	DC	AC
Bar		Party	£/kW	£/kW	£/kW*	£/kW	£/kW*
1	11	Demand	29.75	26.57	25.43	35.66	36.51
2	33	Demand	27.14	22.01	21.08	26.78	25.77
3	11	Demand	29.75	30.54	30.08	46.72	51.50
4	33	Demand	27.14	26.44	24.60	29.10	27.18
5	11	Demand	29.75	33.58	32.02	54.93	56.22
6	33	Demand	27.14	22.64		25.94	
7	33	Demand	27.14	25.00	25.79	26.00	26.23
8	33	Demand	27.14	32.60	46.87	25.59	35.90
9	33	Demand	27.14	48.58		26.18	
10	33	Demand	27.14	57.73	57.68	26.42	24.33
11	11	Demand	29.75	52.36	51.08	26.18	23.59
1	11	Generator	7.50	-8.40		-10.24	
2	33	Generator	7.00	-3.84		-1.35	
3	11	Generator	7.50	-12.37		-21.26	
4	33	Generator	7.00	-8.28		-3.69	
5	11	Generator	7.50	-15.39		-29.46	
6	33	Generator	7.00	-4.47		-0.53	
7	33	Generator	7.00	-6.84	-6.79	-0.59	-0.93
8	33	Generator	7.00	-14.43	-13.57	-0.18	-0.56
9	33	Generator	7.00	-30.41		-0.77	
10	33	Generator	7.00	-39.57		-1.01	
11	11	Generator	7.50	-30.42		-0.76	
% price control recovered by marginal charges			**100%**	**39.3%**	**43.0%**	**15.2%**	**19.3%**