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Framework for Assessing the Economic Efficiencies of Long-Run Network Pricing Models

Furong Li, *Senior Member, IEEE*, David Tolley, Narayana Prasad Padhy, *Senior Member, IEEE*, and Ji Wang, *Member, IEEE*

***Abstract*—This paper presents a framework for assessing the economic efficiency of different long-run network pricing models. The aim is to provide a quantifiable efficiency measure that will inform regulators, network operators, and network users when an alternative pricing model is contemplated. The efficiency measure is derived from the long-term network development costs that flow from a dynamic interaction between network pricing and planning; that is the response of network users to differing charging models, the consequential network investment, and new financial incentives that follow reinforcement of the network.**

To illustrate the approach, the framework has been used to assess the relative efficiency of three broad class of distribution pricing models in a study undertaken for the Great Britain (GB)'s regulator for gas and electricity markets in England, Wales, and Scotland—Ofgem. The study contemplated three pricing models that are used in practice. The efficiency assessment in the Ofgem study was conducted on a pseudo distribution reference network. On the assumption that the results from the reference network could be scaled up to the national level, then the assessment suggests that by moving from the present DRM model to the more economic LRIC approach, GB distribution network operators could save in the region of £200 m over the next 20 years in their network investment costs.

This paper draws heavily on the project undertaken for Ofgem, but any views expressed are solely those of the authors.

***Index Terms*—Distribution network pricing methodologies, dynamic interaction, embedded generation, investment cost-related pricing, long-run incremental cost pricing.**

I. Introduction

ELECTRICITY generation and demand in the U.K. are expected to change significantly over the next 20 years. All but one of the nuclear power stations (7 GW) will retire between now and 2020, as will many coal and oil fired power stations in order to meet EU Environmental Directives. Meanwhile the demand for electricity continues to rise at around 1% per annum. It is estimated that by 2020, some 20-25 GW of new generation will be needed to replace closing capacity and meet the increases in electricity demand [1].

The EU Directive requires 20% of all energy to be from renewable sources by 2020. This is expected to translate into a 15% overall target for the U.K., which in turn implies that up to 35% of electricity generation will need to be from renewable technologies by 2020. The U.K. government now favors a renaissance of nuclear power which would impact the contribution that can be anticipated from gas, coal, and oil fired power stations [2].

Given these uncertainties, transmission and distribution network companies will find it increasingly difficult to plan their networks. These uncertainties are not unique to the U.K. but shared by the majority of the developed countries. If network companies devise their plans against a set of perceived future scenarios, the planning could be both complicated and expensive since it would need to be cost-effective across a range of possibilities. Worse, if the reality turns out to be very different to all of the projected scenarios, then investment will be stranded. On the other hand, if network companies simply respond to firm applications for generating capacity then the long lead times for network upgrading and expansion could frustrate the connection of new generation.

The only certainty that network companies have is their existing networks and their ability to connect new generation or demand at varying locations. Although a network company cannot insist that generation or demand sites at a specific location, it can use financial incentives to guide them to locations that require the least network upgrading and expansion commensurate with the requirements of the user. These financial incentives can be embodied in the form of charges for use of the network.

Network charges can be framed with differing degrees of complexity, depending upon how the costs of a network are evaluated and then allocated. The costs of a network may be determined as the historic costs of accommodating existing network users only, the future costs of accommodating new customers only, or some composite of both approaches [3]–[18].

Once the cost has been evaluated, then there exists a number of cost allocation methodologies. The simplest allocation method is a postage stamp approach that uniformly allocates network costs regardless of customers' geographic locations. The more advanced techniques distinguish the costs of the use of the network at different locations, reflecting the distance traveled in supporting a 1 MW, 1 MVAr, or 1 MVA nodal injection or withdrawal. The costs are expressed in MW-Miles, MVA-Miles, or MW+MVAr-Miles [19]–[22].

Although it is possible to assess qualitatively how one pricing model might be more efficient than another, it is important to es-

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F. Li is with the Department of Electronic and Electrical Engineering, University of Bath, Bath BA2 7AY, U.K. (e-mail: f.li@bath.ac.uk).

D. Tolley was with Npower Ltd. He is now proprietor of DLT Consulting, an independent consultancy to the electricity industry, Winchester, Hampshire SO22 5JT, U.K. (e-mail: dltconsulting@btinternet.com).

N. P. Padhy is with the Indian Institute of Technology Roorkee, Roorkee 247667, India, and also with Ryerson University, Toronto, ON M5B 2K3, Canada (e-mail: nppeefee@iitr.ernet.in; nppadhy@ee.ryerson.ca)

J. Wang is with the North China Grid Company, Beijing 100053, China.

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tablish the magnitude of benefit that will result by replacing one pricing model with another over a long time horizon. This will help inform regulators, network operators, and network users as to the value of moving to any new pricing arrangement.

Previous approaches to assessing the efficiency of different pricing models have been limited to qualitative considerations. The relative merits of different pricing models are ascertained from comparisons of different pricing principles, the resulting prices, and stability of the revenue recovery for changes in network power flows and user behaviors [3], [5], [6], [8], [19], [28], [29]. Very limited research has been undertaken to show how various pricing models might impact on long-term network development. Paper [9] acknowledged the dynamic interaction between network planning and pricing and proposed a pricing strategy based on the long-term network development cost, but no account was given of how network users' responses might change both the network planning and the consequential pricing. To date, there has been no development in a common platform that can quantitatively compare competing methodologies for pricing network services.

This paper proposes a framework that for the first time evaluates the economic efficiency of network pricing models, quantifying the magnitude of the cost savings that can be achieved over a fixed time horizon. The approach seeks to assess the response of new and existing network users to pricing signals provided by any new pricing regime and the consequential investment in the network. Network users in this context include both generation and load. Using the existing pricing methodology as the benchmark, the efficacy of different pricing methodologies can be assessed from the investment needed in the network to meet the requirements of load and generation driven by each pricing methodology.

To illustrate its effectiveness, the proposed assessment framework has been applied to demonstrate the potential long-term benefits to distribution businesses in moving to an economic network pricing model. The assessment is conducted by examining, which out of a number of competing pricing methodologies, would be most effective at encouraging the economic development of the distribution network, particularly in view of the prospect of a significant increase in distributed generation. Efficiency is measured from the overall network development cost over a time frame of 20 years.

Three pricing models are considered in this study: 1) the Distribution Reinforcement Model (DRM)—a postage stamp cost allocation approach for each voltage level [23]; 2) Investment Related Cost Pricing (ICRP)—based on incremental cost pricing principle, evaluating the network cost in accommodating additional increment of generation/demand at a study node. The cost evaluation considers the distance that power must travel from points of generation to points of consumption (MW-Miles or MW+MVAr-Miles) [24], [25]; 3) Long-run Incremental Cost Pricing (LRIC)—like ICRP, based on incremental cost pricing principle. LRIC considers the degree of circuit utilization in addition to the distance. Utilization is incorporated by considering how a nodal increment might impact on the present value of future investment [18]. The methodology has been adopted by Western Power Distribution (WPD), which is the distribution network operator for South Wales and the South West of England, for deriving their EHV network charges from April 2007.

The rest of this paper is organized as follows. Section II describes the detailed steps in developing the proposed assessment framework and characterizes the differing pricing models considered in the study. Sections III and IV present the nodal price evolutions that arise from the assessment framework for the differing pricing models. Section V gives the total network development costs over the study period consequent upon the application of the different pricing models. Finally conclusions are drawn in Section VI.

II. Proposed Assessment Framework

The proposed assessment framework is undertaken in four stages. The first stage is to devise a reference EHV network. Load and generation are connected such that DC and AC power flow studies can be conducted. An associated asset register and revenue target enable the application of the DRM to assess the charges that might apply under present pricing arrangements if the reference network were a single distribution system.

The second stage in the assessment framework is to consider a number of different pricing models that will produce various possible prices for EHV customers who use the system. The models considered were:

- *DRM with site-specific EHV charges.* This model is intended to reflect broadly the most widely found pricing arrangements for heavy loads connected to distribution networks.
- *DC load flow with Investment Cost Related Pricing (ICRP).* This model utilizes the same approach as that employed by the system operator for calculating transmission use of system charges in England, Wales, and Scotland [24].
- *AC load flow with ICRP.* This is an AC load flow version of the ICRP model that more accurately reflects the costs of using the system, as due account is taken for reactive power flows in the network [25], [27].
- *DC load flow with Long Run Incremental Cost (LRIC).* The LRIC model employs the same DC load flow calculation as for ICRP but the treatment of costs from accommodating new generation and demand now reflects the utilization of existing assets [17], [18].
- *AC load flow with LRIC.* This model employs the same AC load flows as for ICRP but now within the context of the LRIC cost model [27]

The DRM model was developed in the early 1980s, designed to respect the passive nature of the distribution network, i.e., power flows from the high voltage part of the network to its low voltage. DRM has been used by many DNOs across the deregulated power industry. It was not designed with a mind for a system with significant embedded generation (EG). As a result, it has two major drawbacks for the present distribution system: 1) unable to recognize the potential contribution that EGs might bring to the system, and 2) unable to guide the location of new EGs to the overall benefit of the network operator and consumers. It is therefore important to consider other more economic approaches that are able to recognize the costs and benefits that the addition of generation or demand will have on the system. In presenting the analysis, the output from the

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DRM model is used as the benchmark against which the ICRP and LRIC models can be assessed. The LRIC pricing model was developed to address two major flaws present in the ICRP approach: 1) ICRP assumes that the existing network is fully utilized for existing customers. Any additional power will thus require immediate reinforcement of the relevant circuits. There is therefore no recognition of the degree of network utilization; 2) ICRP assumes that the circuit components are infinitely divisible and that an additional 1-MW power flow can be met by the addition of circuit component with a 1-MW rating [18].

The third stage is to devise a customer behavior model that mimics the response of generation and demand customers to prices derived from the various pricing models. For generic classes of customers connected to the HV and LV networks, price elasticities taken from published studies are used to derive anticipated changes in demand following a change in price. However, in the chosen reference network, half of industrial load is connected at EHV. EHV connected load is assumed to be more price elastic than other industrial load connected at lower voltages. The growth in EHV load is taken to manifest itself as new large customers that site on an economically rational basis and choose locations that have the lowest connection cost and use of system charges. It should be emphasized that the study seeks to explore the economic efficiency of different pricing models in isolation. Consequently the availability of primary energy sources, technology costs, the availability of land, and the practicality of connections and planning permissions are not considered in this study.

The final stage in the assessment framework is to devise an investment model that calculates the investment costs necessary to keep the system secure as a consequence of the patterns of demand and distributed generation that result from customer reaction to the various pricing models. The relative costs of developing the distribution network to accommodate demand and generation over a 20-year period is taken as the measure of the effectiveness of the pricing methodology in encouraging efficient investment, and hence the value of changing to a different pricing arrangement.

A. Generation Response Model

In deciding the location at which 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 plant, the anticipated fuel price. Given the uncertainty of movements in fuel prices over a long time horizon, the anticipated price is taken to be hedged against future price changes at the time of connection.

Generators are assumed to site at the network location that will give the most favorable rate of return as viewed at the time of connection. It is assumed that there will be sufficient price support for renewable technologies 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.

For generators, the AC models provide a choice of three operating power factors depending upon the nodal prices calculated for the provision of reactive power by the network operator. If the price of reactive power from the network is cheaper than the cost of providing local compensation, then the model will assume that it is unnecessary for a wind generator, for example, to install reactive compensation and instead it is more economical to 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 the network.

The investment model is based on an economic rationale of cost-effectiveness. It should therefore be generally applicable in other regulatory jurisdictions although these may differ in their renewable strategies and policies. Policy objectives could be reflected either in the price of electricity, the price of fuel, or the incentive provided to renewable generation.

B. Demand Response Model

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. The equation usually employed for expressing price elasticity is

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

As an assumption for this study, the price elasticity for each customer grouping is taken as that recommended by the Australian National Institute of Economic Research (NIESR) in 2004 [26]. These relate to an economy that is not dissimilar to that in the U.K. 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 were

$$\begin{aligned} \text{Residential} &\quad -0.25\\ \text{Commercial} &\quad -0.35\\ \text{Industrial} &\quad -0.38. \end{aligned}$$

The price elasticities for residential, commercial, and industrial customers can vary significantly from one country to another, but country specific estimates are often unavailable. In the absence of better information, the price elasticities used in this paper could serve as a proxy.

C. Network Investment Model

The investment model devised examines the network reinforcement necessary to maintain the required security and quality standards, as load and generation materializes at different locations in response to the output of each of the pricing models. The position is considered at five yearly intervals, assuming that the new pricing regimes were implemented from 2005 and that government renewable generation targets were met. The study period extends from 2005 to 2025.

The physical consequence of demand growth is expressed in terms of the voltage at each bus-bar and the thermal loading of circuits and transformers. The model installs static voltage compensators (SVCs) to correct any under-voltage situation that may emerge from the load flow analysis. In the event that the

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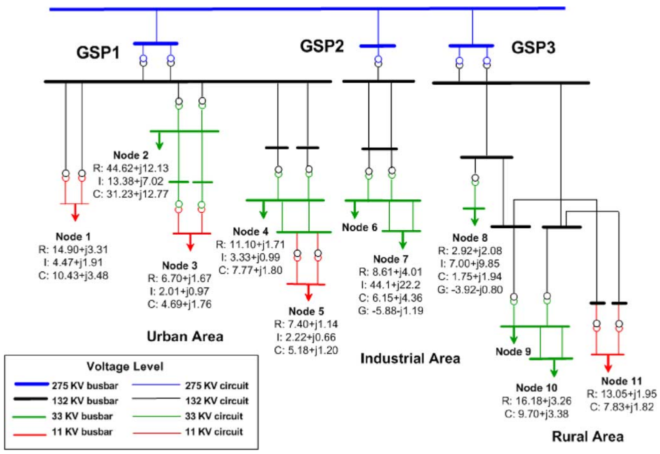

Fig. 1. Reference network comprising rural, urban, and industrial areas.

current in circuits and transformers exceeds their thermal ratings, then the model employs the next standard size of overhead lines, cables, or transformers.

In the case of new distributed generation, the consequence for voltage at each bus-bar is again considered together with the thermal loading of circuits and transformers and the impact on system fault levels. If voltages exceed statutory limits, then the model again installs SVCs to compensate. 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 make the network compliant with its design standard.

III. Application of the Framework to the U.K.'s Distribution Network Pricing Regime

The framework is applied to demonstrate the differences in future network investment cost driven by the five pricing models [27]. Each pricing model would influence the locational growth of generation and demand in a different way, and this will in turn shape the network investment required in a different manner to maintain the security and quality of electricity supplies. The economic efficiency of each pricing approach can be assessed by applying the investment model described above to determine the quantum of capital expenditure required to accommodate new load and generation under each pricing methodology.

Fig. 1 shows the reference network used in the study. It has 275 MW of connected load and 10 MW of distributed generation at the start of the study period. The network is based on a practical system and comprises of three service areas representing three types of customer: urban, rural, and industrial. The urban area (GSP1) has circuits that are short in distance but heavily utilized, the rural area (GSP3) has circuits that are long but lightly loaded, and the industrial area (GSP2) displays average circuit lengths and loading levels.

A. Pricing Signals for Different Methodologies

The results derived from the pricing models in the first year of the study period are compared in the diagrams below. Fig. 2 shows the marginal rates derived from each pricing model. The application of pure economic marginal rates as prices will usually tend to under or over recover the allowed revenue that is

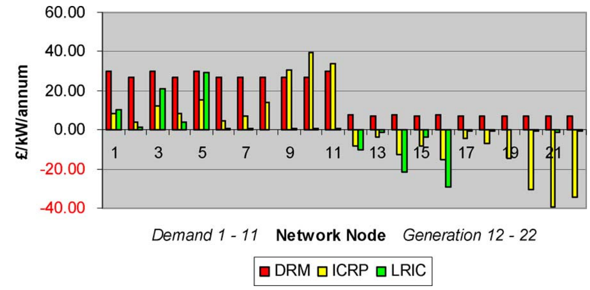

Fig. 2. Marginal costs derived from each pricing model.

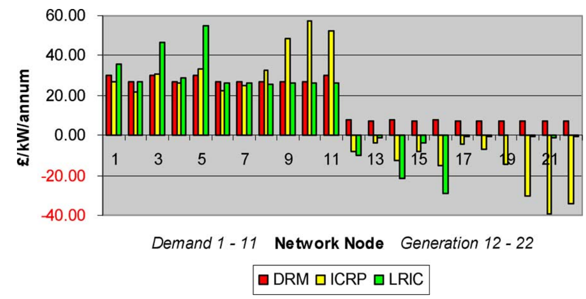

Fig. 3. Marginal costs scaled to produce tariff at each node.

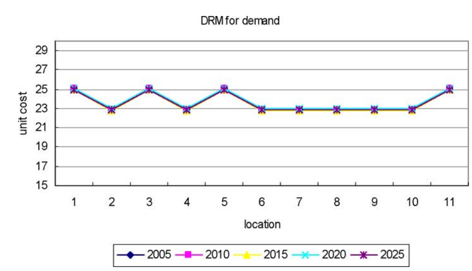

Fig. 4. Nodal price evolution for demand with DRM model.

permitted by the regulatory price control. Rates therefore need to be scaled up or down to match the allowed revenue. Fig. 3 indicates the effect of the scaling assumption used to create tariff rates that will produce the revenue recovery. Prices at nodes labeled 1–11 are the rates chargeable to load at each node in the reference network, whereas prices at nodes 12–22 are the generation rates at the same sequence of demand nodes.

IV. Customer Response and Price Evolution

A. Customer Response to the DRM

The manner in which prices are derived in the DRM produces network charges that are the same at each voltage level for all geographical locations, shown by Fig. 4. Because network charges are a relatively small proportion of the overall price, and the price elasticity is low, the dilution of the network charge by other components of the overall price makes for an imperceptible response from larger customers connected at EHV to a change in the level of the use of system charge. Annual demand growth is taken to accord with the underlying trend of 1.6% per annum. The only significant perturbation to the model is thus caused by the siting of new large industrial load, which is assumed to connect at the central bus-bar 6 in Fig. 1, since this is within an industrial area.

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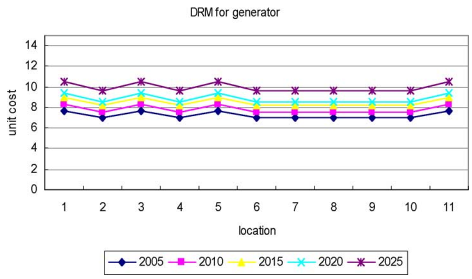

Fig. 5. Nodal prices evolution for generation with DRM model.

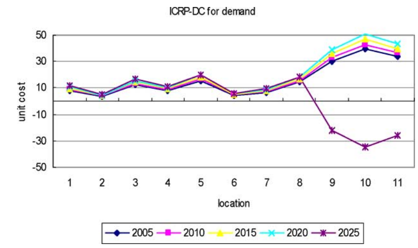

Fig. 6. Nodal price evolution for demand with ICRP model.

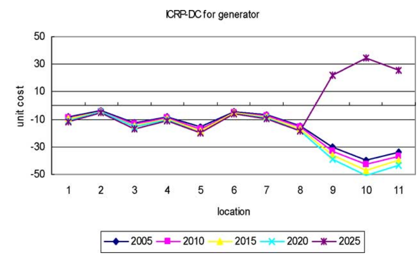

Fig. 7. Nodal price evolution for generation with ICRP model.

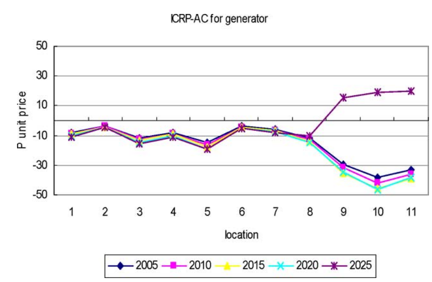

Fig. 8. ICRP-AC generation real power price evolution.

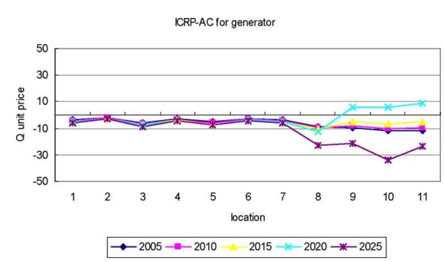

Fig. 9. ICRP-AC generation reactive power price evolution.

Similarly because the DRM has no pricing signal for location, shown in Fig. 5, the model assumes that new distributed generation will situate at a location that is most appropriate for the type of generation. Thus, the higher wind speeds associated with the terrain around location 8 in Fig. 1 will make this the obvious locations for wind generation, while the industrial network at location 6 will be the obvious place for CHP generation to connect.

The approach for deriving generator use of system charges (GDUoS) 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 decreases slightly towards the end of the period as the overall target revenue is met.

B. Customer Response to ICRP (DC Power Flow)

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.

At first generation is attracted to the distant nodes 9,10, and 11 because of the high credits created by the ICRP model, 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 the least, and prices the lowest, despite being heavily loaded.

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. In turn, this 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.

The effect is dramatically illustrated in Figs. 6 and 7 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 short distances to the GSP display a more stable pricing signal under the model.

C. Customer Response to ICRP (AC Power Flow)

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. The analysis assumes that wind generation absorbs reactive power in the production of active power. Figs. 8 and 9 show the generation's real and reactive power pricing change over the study period, where the reactive power charges change as customers adopt different operating power factors to minimize their reactive power cost.

D. Customer Response to LRIC (DC Power Flow)

The LRIC-DC model produced a nodal pattern of prices that are strikingly different to that produced by the ICRP models, shown in Figs. 10 and 11. Nodal prices are now driven by both the distance the load or generation is from the GSP and the utilization of the network assets. As a consequence, demand prices and generation credits for some of the urban nodes tend to be relatively high, while 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 leads to a more efficiently configured network. Charges at all nodes converge over the period as demand and generation

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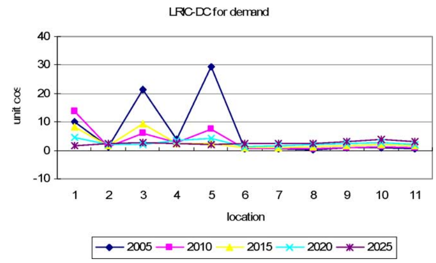

Fig. 10. Nodal price evolution for demand with LRIC model.

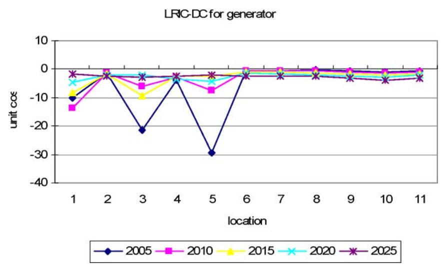

Fig. 11. Nodal price evolution for generation with LRIC model.

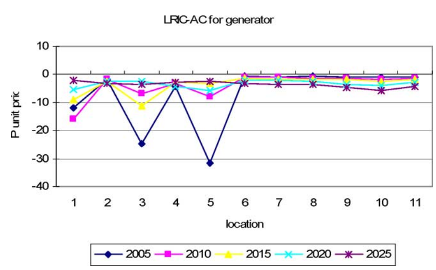

Fig. 12. Nodal price evolution for LRIC model.

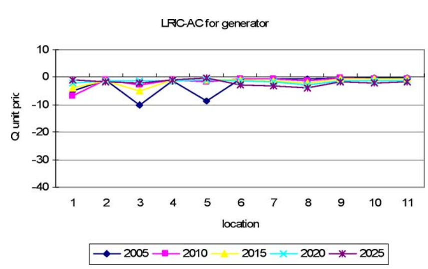

Fig. 13. LRIC generation real power price evolution.

are attracted to locations where they can make optimal use of the network. In time, equilibrium should be reached between the cost and utilization of the assets at a node.

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.

E. Customer Response to LRIC (AC Power Flow)

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, shown by Figs. 12 and 13. This is because the capacity in the system is utilized more rapidly in order to accommodate the reactive power flows.

TABLE I
PRESENT VALUE OF REFERENCE 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

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.

V. CONSEQUENCES FOR INVESTMENT COSTS

Table I summarizes 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.

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

A. Generation-Related Investment Under Different Pricing Models

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. The investment model indicates that the highest system cost for accommodating generation and demand is associated with this pricing methodology. Under the ICRP models, generation would tend to concentrate at the most distant nodes since these present the best credits for generation. The attractiveness of these nodes in terms of price only ceases when the quantity of new generation causes the power flow at the node to reverse. This effect has already been seen at distant nodes on the GB transmission network where the ICRP pricing model is employed.

The LRIC models demonstrate a major advantage in that the pricing incentive causes generation to site where assets are most heavily loaded. As a consequence, no investment is needed to accommodate the growth in demand. Effectively the optimal location of generation obviates the need to reinforce the system for demand growth.

Fig. 14 shows the cumulative network investment cost for new generation under different pricing models. 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 marginally outperformed the ICRP-AC model. The merit of the AC pricing model

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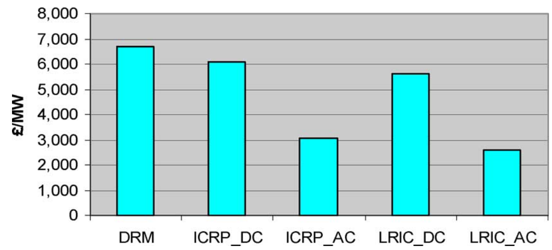

Fig. 14. Present value in £/MW of network investment cost for new generation under different pricing models.

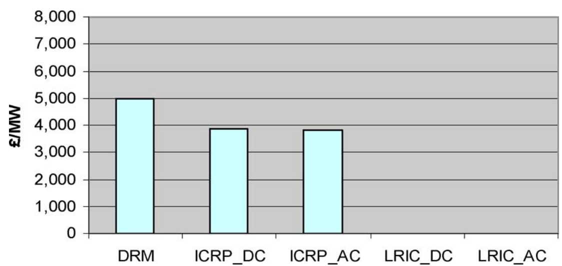

Fig. 15. Present value in £/MW of network investment cost for meeting new load under different pricing models.

variant is that it also reflects the costs of meeting the network requirements for reactive power.

B. Demand-Related Investment Under Different Pricing Models

The principal investment cost that results from the addition of new load was the increase in transformer capacity and circuit reinforcement as a result of thermal limitations and under-voltages. The LRIC models encourage generation to locate at the most heavily loaded nodes, thus obviating the need for system reinforcement at these locations to accommodate future demand. As noted, the reinforcement cost for demand under this pricing model was thus zero.

The ICRP models require most investment for the connection of incremental load. This follows from encouraging load to site at nodes that have the least distance from the associated GSP without reference to the utilization of the relevant assets, which in the reference network are the most heavily loaded circuits and transformers.

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 charges are not reflected in the derivation of the demand response to the pricing signals, the investment model calculates the same investment cost for both the DC and AC variants of the ICRP and LRIC models.

Fig. 15 shows the network investment cost associated with accommodating demand under different pricing models. It demonstrates that in an uncertain commercial environment, network pricing can play a vitally important role in influencing the future pattern of generation and demand, which in turn shapes the network development. LRIC is shown to have the best potential to attract generation and demand to places that lead to the least cost in developing the network.

While it may not be practical for all generation and demand to locate at places to minimize network development costs because of the availability of primary fuel sources or planning constraints, a significant number of new users will have flexibility in their choice of location, including energy intensive loads such as some computer centers and CHP plants. If users do not respond to the economic message from the network operator, then they will either have to bear the higher network charges or lose the potential credits they could otherwise earn.

VI. Conclusions

This paper proposes a new framework for assessing the economic efficiency of different network pricing models. The efficiency measure is derived from the long-term network development costs that flow from a dynamic interaction between network pricing and planning; that is the response of network users to differing pricing models, the consequential network investment, and new financial incentives that follow reinforcement of the network.

To illustrate the approach, the proposed framework has been used to assess the relative efficiency of five different distribution pricing models in a study undertaken for the regulator of the gas and electricity markets in Great Britain—Ofgem. First, the proposed framework has been applied to the DRM, which is essentially a postage stamp allocation of costs at each voltage level. This creates a baseline against which to judge the benefits of alternative pricing models based on economic principles. Four pricing methodologies were assessed. These were the ICRP model that is based on the distance that power must travel to serve customers, an AC variant of the ICRP model, and two new LRIC pricing models developed by the University of Bath that reflect both the distance and the degree of asset utilization.

The DRM model does not provide any pricing signal for the location of future generation and demand. As a consequence, it produced the highest investment cost for developing the reference network over the study period of 20 years (from 2005–2025). The ICRP pricing model reflects the cost of reinforcing circuits of different lengths, and resulted in a slightly lower cost in accommodating future generation and demand. In the case of the LRIC model, the cost of network development to accommodate generation was similar to that of ICRP, but it incurred no extra cost in meeting future increases in demand. This resulted in significant cost savings.

The LRIC-AC model showed the greatest 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, over a 20-year period. If the saving of £830 k for the reference network could be extrapolated across the GB system, it would imply a saving in investment costs over the 20-year study period in the region of £200 million.

Ofgem has relied on this study in urging six of the seven GB distribution businesses that hold 12 DNO licenses and who continue to use the DRM for the EHV parts of their networks to move to a more economic pricing model. It should be noted that one DNO has implemented the LRIC approach for their EHV networks from April 2007. On October 1, 2008, Ofgem published a Decision Document promoting a Common License Modification that would require all DNOs to adopt the LRIC principles for their EHV distribution networks on the grounds that it represented the best available long-run pricing model to date [31].

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Furong Li (M'00–SM'09) was born in Shanxi, China. She received the B.Eng. degree in electrical engineering from Hohai University, Nanjing, China, in 1990 and the Ph.D. degree in 1997 with a thesis entitled "The application of genetic algorithms in optimal operation of electrical power systems".

She took up a lectureship in 1997 in the Power and Energy Systems Group at the University of Bath, Bath, U.K., where she is now a Senior Lecturer. Her major research interests are in the areas of power system planning, operation, automation, and network pricing.

David Tolley received the B.Sc.(Eng) degree from Queen Mary College, University of London, London, U.K., and the M.B.A. degree from the Manchester Business School, Manchester, U.K.

Much of his career has been in the electricity supply industry. He was closely involved with the privatization of the U.K. industry in 1990 and held the post of Commercial Manager at National Power and Innogy plc, before being appointed Commercial Director of npower, the retail arm of RWE npower. He now Proprietor of DLT Consulting and a Senior Visiting Research Fellow at the University of Bath, Bath, U.K.

Mr. Tolley is a Fellow of the Institute of Engineering and Technology.

Narayana Prasad Padhy (SM'09) received the Ph.D. degree in power systems engineering from the Indian Institute of Technology (IIT) Roorkee, Roorkee, India, in 1997.

He was a Professor in the Department of Electrical Engineering, Indian Institute of Technology (IIT) Roorkee. During 2005–2006, he worked as a Research Fellow in the Department of Electronics and Electrical Engineering, University of Bath, Bath, U.K., and is currently working as a Research Fellow in the Department of Electrical and Computer Engineering, Ryerson University, Toronto, ON, Canada.

Ji Wang (M'03) was born in Henen province, China. He received the M.Sc. degree with merit in electrical power at the University of Newcastle, Newcastle, U.K., and the Ph.D. degree in electrical and electronic engineering at the University of Bath, Bath, U.K.

Now, he is in charge of distribution network operation at the North China Grid Company, Beijing, China. His areas of interests are electrical market, network pricing, distribution network, and system operation.

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