Risk Management in Use-of-System Tariffs for Network Users

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***Abstract*—Network use-of-system (UoS) tariffs play an essential role in the deregulated power markets to recover network investment and maintenance costs from network users, and send economic signals to influence the users' behaviors in using systems. The tariffs are essential to the business operation of both network operators and users. They, however, could have great volatility due to the uncertainties from both external and internal factors. Such uncertain tariffs could bring severe adverse impacts to network users, which justifies that there is an urgent need to reduce the tariff volatility and improve its predictability. This paper for the first time investigates the variations in network tariffs that cause great risks to network users and then designs financial tools to reduce the volatility. The causing factors of the variations are categorized into global and local groups according to their different features. After introducing the process from network planning, charging to revenue reconciliation, the paper discusses the benefits of hedging for network users. In order to reduce tariff volatility, it proposes a novel risk management strategy to maintain the consistency of tariffs. It is achieved by designing long-term contracts using financial hedging. The value of hedge contracts is decided by three key factors: hedged load/generation percentage, hedged price, and risk premium. The hedged part is charged at hedged prices and the non-hedged part is charged at actual prices, on top of which customers needs to pay extra for the risk premium. The paper also designs an optimal decision-making tool to assist network users to manage long-term contracts in order to reduce total tariff costs. As demonstrated in the case study, the proposed long-term products can effectively reduce tariff volatility for network users and create a safe environment for their business operation.**

***Index Terms*—Fixed adder, long-term contract, network pricing, revenue reconciliation, risk management, uncertainty.**

I. Introduction

In deregulated environment, generation and demand need to pay for their use of transmission and distribution networks, which comes into the form of use-of-system tariffs collected by network operators [1], [2]. Network tariffs are economic media that closely link network operators and users apart from the physical infrastructure. The tariffs serve two major purposes: 1) to recover network investment, operation, and maintenance costs from network users; and 2) to influence network users' decisions in connection sizes and locations for minimum network investment [3]–[8]. Network tariffs are not only important to network operators but also to customers as the tariffs take up a large proportion of their capital costs. In the U.K., network tariffs account for around 21% of the total electricity bills for a typical domestic customer [9].

Network tariffs are calculated according to the investment in networks and their utilization by network users. In the deregulated environment, network planning is conducted in a decoupled manner in order to accommodate the increasing generation and demand. Particularly, to meet carbon reduction targets, a large volume of low carbon technologies will be connected to existing power networks, such as wind power, solar generation, electric vehicles, heat pumps and energy storage devices. These new low carbon technologies will bring great uncertainties to network planning due to their intermittency/unbounded increase. The situation is further complicated by the fact that the individual behavior change of some users can affect network utilization and consequently network planning and tariffs for other users. Therefore, in reality, it is very hard to precisely predict network investment costs. The adverse impact is the volatility of network tariffs, defined as tariff risk, which is inevitable for demand and generation and can threaten their business operation.

In practice, it would be extremely beneficial for both network operators and users if the variation in network tariffs could be reduced to some extent or their patterns could be predicted with acceptable accuracy. The reasons are that: 1) network operators have to obey the mandatory regulations set by regulators to produce cost-reflective and transparent tariffs, and 2) network users are vulnerable to tariff fluctuation and prefer a relatively safe financial environment. The watchdog of the U.K.'s electricity and gas markets—the Office of Gas and Electricity Markets (Ofgem)—requires that distribution network operators (DNOs) should look at developing methods to address the volatility of distribution tariffs [10], [11]. In one of its official documents on network tariffs, Ofgem states that DNOs are required to develop long-term charging products in order to address any concerns consumers may have with annual volatility of distribution tariffs, particularly at extra-high voltage (EHV) distribution level, and DNOs are required to develop tools to help customers understand and model their future tariffs [10]. In a survey conducted by the Energy Network Associate (ENA) in the U.K., the industry stakeholders have expressed a high interest in developing mechanisms to enable distribution tariffs to be fixed or more stable and transparent [12]. Although it is impossible to accurately predict network tariffs, it is possible to reduce and mitigate their volatility, i.e., risk, by financial tools.

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Risk is the potential loss or an undesired outcome caused by the choice of a chosen action or the choice of inaction. Risk assessment in power systems is not new and can be generally categorized into two areas: technical risk analysis and economic risk analysis [13]. The former focuses on the technical risk assessment in power systems, while financial risk management refers to the process of analyzing risk exposure and attempting to minimize the risk though financial means, including diversification, hedging, leverage etc. Lots of research efforts have been put into risk management in energy market [14] and [15], but there is no research conducted in risk management for network tariffs, despite that the industry is very keen to understanding the possibility, benefits and challenges in risk management for network tariffs. The work proposed here is to fill the gap by designing long-term products to reduce network users' exposure to tariff risk.

This paper is directed to understand the causes for the uncertainties in network tariffs and design long-term products to reduce the tariff volatility for network users. It investigates the causes by examining the process from network planning to charge calculation and revenue recovery. It thereby proposes long-term contracts to reduce the risk network users' are exposed to by fixing their network tariffs for a chosen period of time using financial hedging. The values of the contracts are decided by three factors: contract length, hedged load percentage and risk premium. In each contract, network users need to pay for the base tariffs plus an extra amount for the risk premium. The long-term contracts can effectively reduce the variations in network tariffs and create a relatively safe environment for network users. This paper also examines the scenario that if network operators provide a group of hedge contracts how network users manage them. An optimization based decision-making tool is introduced to help network users to manage long-term contracts in order to mitigate risk and minimize total costs.

The key contributions of the paper are: 1) it investigates the factors affecting UoS tariffs by examining network planning, charge calculation and revenue reconciliation; 2) it for the first time proposes long-term contracts to reduce the risk in network users' UoS tariffs; 3) further it designs an optimization-based decision-making tool to assist network users to manage long-term contracts for minimum tariffs.

The rest of this paper is organised as: Section II introduces the factors causing volatility in network tariffs. In Section III, hedging and its benefits in the practical application are introduced. Section IV designs long-term contracts and Section V develops an optimal contract management tool for network users. Section VI provides a case study to demonstrate the value of proposed methodologies. Section VII provides a discussion and Section VIII concludes this paper.

II. Volatility in Network Tariffs

A. Network Planning, Charging, and Revenue Recovery

In deregulated environment, the generation, transport and consumption of electricity is conducted in a decoupled manner. Network operators are responsible for network planning, operation, and maintenance and their activities are regulated by the regulators. Generation and demand use networks to transport the electricity and pay network operators for the use. Network users' right to use networks and the liable costs are protected by regulators to ensure fairness. To this end, network charging methodologies are utilized to calculate the costs that users need to pay for their use of networks, which come in the form of network charges.

Currently in the U.K., DNOs use two levels of charging methodologies to derive network charges: common distribution charging methodology (CDCM) used for LV and HV customers (the connecting network voltage level equals to or below 11 kV) and extra-high voltage (EHV) distribution charging methodology (EDCM) methodology (the connecting network voltage is higher than 11 kV). CDCM is largely referred to distribution reinforcement model (DRM) [16]. By contrast, EDCM consists of two common methodologies—long-run incremental cost (LRIC) pricing and forward cost pricing (FCP). For EDCM customers, as required by Ofgem, DNOs can choose either of the two methods to implement in practice. LRIC pricing evaluates the investment costs necessary to accommodate new generation and demand in a network and appropriately assigns the cost to network users in an incremental way [1], [7]. By contrast, FCP pricing is an average pricing model. It evaluates the total network investment costs over next 10 years and allocates the costs evenly to all existing and forecasted demand and generation customers in the same zone. The aim is that the total revenue recovered over the 10 years period equals to the forecasted reinforcement costs over the same period [16]. The detailed theory and implementation procedures for the two methodologies can be found in the following papers and publications: LRIC [1], [17]–[19] and FCP [16], [20]–[22].

The total allowed costs that network operators can recover from EDCM and CDCM network users is called revenue recovery. The revenue is proportionally split between the two groups of customers based on the investment and maintenance costs of on-ground network assets at each voltage level and customer sizes. EDCM customers are only liable for EDCM charges, while CDCM customers are liable for both EDCM and CDCM charges. Usually, the total recovery based on charging models results in either a shortfall or a surplus. In this case, the charges need to be scaled up or down to mitigate the imbalance, which is termed as revenue reconciliation. There are two commonly adopted revenue reconciliation approaches-"fixed adder" and "fixed multiplier" [20], [23]. The fixed adder method adds/subtracts a constant amount to/from all nodal charges to make up for the revenue shortfall/surplus. The multiplier method scales all nodal charges by a constant factor—the ratio of the allowed revenue to the recovered revenue. The recent progress in improving scaling approaches targets at amending fixed adder to incorporate more planning concerns to properly allocate the unrecovered revenue. The examined approaches by DNOs are traditional fixed adder, voltage level adder and site specific adder [24]. In this paper, only site specific adder is used for scaling up/down charges. This scaling approach allocates the unrecovered revenue based on the level of assets used by each demand customers. Instead of assuming the average use of assets at each network level by each customer, it utilizes a "network use factor" for each customer to measure their use of system [20]. The network use factor of each component for a particular customer can be obtained through power flow analysis [21]. The methodology for calculating site specific adders and demonstration examples can be found in [21] and [24].

The unit tariffs are the summation of network charges and adders (decided by revenue ports). Increasing network utilization produce bigger network charges and increasing revenue ports generate larger site specific adders. When revenue ports are fixed or become smaller, increasing network utilization leads to decreasing site specific adders.

B. Network Tariff Volatility

The volatility in network tariffs means that year-on-year tariffs change dramatically, which is mainly caused by the uncertainties and variations of the inputs into network charging methodologies. These uncertainties are very hard to predict and could have great impacts on network tariffs. According to their different features, the uncertainties can be roughly divided into global and local groups.

1) Uncertainties in global group include national and regional economic growth, which have direct influence on electricity generation and consumption, and environmental regulations and legislations that impact operators' investment, etc. These uncertainties are beyond their control but have to be considered in network planning. For example, in order to support governments' ambition in reducing CO_2 emission, network operators have to ensure sufficient network capacity to accommodate intermittent renewable generation and low carbon demand which are hard to be precisely predicted;
2) Uncertainties in local group are defined as the factors which are mapped into charging models and have direct impacts on network tariff calculations, such as customer coincidence factors for DRM, discount factor for LRIC and FCP, network utilization level. One predominate example here is that the behavior change of one customer can affect the network tariffs other users need to pay. It is because the allowed revenue recovery is divided among network users according to their sizes and locations, and therefore their behaviors will directly change network utilization and the split of revenue, and consequently the tariffs they and other customers pay.

These uncertainties cause network tariffs to vary to some extent over time and be hard to predict. Such volatility could have detrimental impacts to network users and therefore there is an urgent necessity to devise technical and economic strategies to mitigate it.

III. Hedging and Its Benefits for Network Users

A. Hedging

Excessive volatility in assets' prices or use of assets' charges may make companies' investment strategies severely distorted by the uncertainties. In this risky environment, the companies' expected rate of return can be highly volatile, which could lead to bankruptcy. For users, they have to face greater variations in their costs [25]. The literatures on risk management argue that hedging, acting as a financial risk management technique, can offset the potential losses caused by the volatility [26]. Hedging has been widely studied and successfully applied into energy markets [27]. It can be constructed from many types of financial instruments, including insurance, forward contracts, swaps, options, many types of derivative products, and perhaps most popular future contracts. The degree of hedging on the forward contracts depends on the hedge contract types and used financial instruments. An appropriate strategy of hedging can produce optimal capital investment outcomes [25], [27].

The standard way to price a forward contract is to find the conditional risk-neutral expected value of the future delivery from the contract [28]. The taker of a forward hedge contract is penalised by an extra payment which is called risk premium. It is priced by the difference between the risk free value and the risk-neutral expected value of the future delivery of the forward contract. One of the peculiarities of commodities markets is that the market price of risk may be either positive or negative, depending on the time horizon considered [28].

B. Benefits of Long-Term Hedge Products

The reason behind creating long-term hedging products is to give network users—suppliers, large generation and demand, whoever have pass-through UoS arrangements—the option to reduce volatility in year-on-year network tariffs. This will aid their business operation by reducing capital risk and increasing cost transparency. In a survey conducted by ENA, suppliers and generation largely stated that long-term contracts would reduce volatility within the distribution UoS market [12]. Some developed this by suggesting that such reduction in volatility would enable suppliers to reduce risk premiums added to their charges for end-use domestic and commercial customers. Energy suppliers will benefit as greater stability in UoS tariffs that reduces the risk to their business will enable them to offer cheaper products to their customers. Generators, particularly renewable generators who have great degree of intermittency, are also supportive of the products and suggest that it would assist them with current and future investment.

IV. Long-Term Hedge Contract Design

In this paper, hedging of distribution network UoS tariffs is achieved through long-term contracts, which fix network tariffs for a certain proportion of demand/generation at a predefined price for a chosen period. The procedures of designing the contracts consist of tariff prediction, risk premium calculation, and hedge contract value calculation.

A. UoS Tariff Projection

In the first step, UoS tariffs are projected for the next regulatory period normally five years in the U.K., assuming no unanticipated changes in the systems except projected demand and generation growth, network expansion and upgrades. The information for the prediction is from network operators' long-term development statements (LTDSs) [29]. The projected tariffs are used as benchmark of hedge contract values. The prediction consists of the following procedures.

1) Collect base year network information, including demand, generation and their growth plus commercial data of network costs data and discount rate;
2) Feed the information into network charging models- LRIC, FCP and DRM—to calculate unit network charges for all studied nodes;

3) Calculate revenue recovery from the calculated network charges;
4) Calculate the allowed revenue recovery and split it into CDCM port and EDCM port;
5) Conduct revenue reconciliation if there is any shortfall or surplus in the revenue recovery via site specific adder to scale up/down unit tariffs.

B. Risk Premium

In designing long-term contracts, risk premium is introduced to reflect customer's aversion to risk. Risk premium has been commonly used in economic risk analysis. A risk premium is the minimum amount of money by which the expected return on a risky asset must exceed the known return on a risk-free asset, or the expected return on a less risky asset, in order to induce an individual to hold the risky asset rather than the risk-free asset [30]. In this work, risk premium indicates that network users are willing to pay more in order that the uncertainties in their tariffs can be reduced. The risk is transferred to network operators [31] and therefore they charge more for bearing the risk.

The magnitude of risk premium depends on the proportion of hedged load/generation percentage, hedged price, and contract length. Once the information and projected tariffs are settled, risk premium can be calculated with (1), which is similar to that used in energy market [31]

$$F_{FR} = \frac{\sum_{t=1}^{T} e^{-d\cdot t} \cdot r \cdot D_t \cdot (P_t - P_0)}{\sum_{t=1}^{T} e^{-d\cdot t} \cdot [r \cdot D_t \cdot P_0 + (1-r) \cdot D_t \cdot P_t]} \quad (1)$$

where D_t is customer's demand/generation size, T refers to hedge contract length, t is year index, r is hedged load/generation percentage, P_0 is hedged unit price, P_t is predicted unit tariff, and d is discount rate.

The numerator term in the risk premium in (1) produces the charge difference between the cases with and without hedging in the contract. The denominator term produces the total charges, where the hedged part is charged at a fixed hedge price P_0, and the other part is charged at the actual yearly varying price P_t. The whole equation generates a percentage, reflecting the potential gain/lose for DNOs to bear the risk caused by fixing network users' UoS tariffs.

In this paper, D_t is the predicted customer's size in Year t. It is determined by a given projected load growth rate against the load size in the initial year. P_t is the predicted unit tariff in Year t corresponding to D_t. P_t can be calculated by either UoS charging methodology-LRIC or FCP, based on the predicted D_t and network information. In this paper P_t is generated by LRIC methodology. Both D_t and P_t are predicated and determined by DNOs, who have the needed information and knowledge for calculating charges. P_0 is the hedged unit price for network users. It should be determined by DNOs themselves based on their financial risk and profit analysis, considering both their risk bearing capabilities and profit expectations. This paper does not investigate the determination of P_0 as it is out of its scope and therefore it uses assumed values for demonstration purposes.

C. Value of Long-Term Contracts

When network users choose to sign up with long-term contracts, they will see less tariff variations. They can benefit by knowing part of their network tariff costs in advance and because of this privilege, they need to pay extra [32]. The final tariffs that a customer pays include three parts: 1) the non-hedged load/generation is charged at the actual unit tariff of each year; 2) hedged load/generation is charged at the hedged unit price; and 3) on tops of the two parts, an extra portion needs to be paid for the risk reduction. The final UoS tariffs take the form of

$$\begin{aligned}\text{Contract Value} &= (1 + \mathrm{F_{FR}}) \\ &\cdot \sum_{t=1}^{T} (r \cdot D_t \cdot P_0) + \sum_{t=1}^{T} [(1-r) \cdot D_t \cdot P_t] \quad (2)\end{aligned}$$

where the variables in (2) are the same as those in (1).

D. Implementation of Long-Term Contracts

Long-term contracts are applicable to both CDCM and EDCM customers as long as they are willing to sign up. By summarizing the foregoing procedures, the proposed contracts can be implemented by operators through the following steps.

Step 1) project network tariffs based on collected network and commercial information;
Step 2) provide a group of hedged load/generation percentage and the corresponding hedged prices;
Step 3) calculate risk premium under each combination of hedged load/generation percentage and price;
Step 4) calculate values of long-term hedge contracts.

V. Optimal Hedge Contract Management

It is anticipated that in order to reduce administration burden and increase the simplicity of long-term contracts, network operators might only be willing to provide a group of hedge contracts for customers to choose. These contracts differ in: 1) hedged load/generation percentage, 2) hedged unit price, and 3) contract length. Under this circumstance, customers are entitled to choose their preferable hedge contracts with different combinations of the three parameters according to their degree of aversion to risk. Because of the interconnection of the three parameters, customers have to understand their impact on contract values and eventually reach to an optimal combination of them for minimum tariffs. Decision-making tools are therefore needed for assisting network customers to choose optimal contracts.

This decision-making in choosing hedge contracts can be modeled as an optimization problem, whose objective is to minimize the overall tariffs over a given period. This optimization problem is to find the right hedged load/generation percentage within each contract to reach the minimum tariffs. The problem is subject to the constraints of hedged load/generation percentage, as modeled in (3)

$$\begin{aligned}\text{Min}: \mathrm{V(r)} &= (1 + \mathrm{F_{FR}}) \sum_{t=1}^{T} (r \cdot D_t \cdot P_0) \\ &\quad + \sum_{t=1}^{T} [(1-r) \cdot D_t \cdot P_t] \\ s.t.: &\quad 0 \le r \le 1 \quad (3)\end{aligned}$$

where the variables in (3) are the same as those in (2).

By substituting (1) into (3), the optimization problem can be converted into the following form:

$$\mathrm{Min}:\mathrm{V(r)}=\frac{r\sum_{t=1}^{T}D_tP_0\cdot\sum_{t=1}^{T}D_tP_te^{-dt}}{\begin{array}{c}r\sum_{t=1}^{T}D_t(P_t-P_0)e^{-dt}+\sum_{t=1}^{T}D_tP_te^{-dt}\\ -r\sum_{t=1}^{T}D_tP_t+\sum_{t=1}^{T}D_tP_t\end{array}}$$
$$s.t.:0\leq r\leq 1. \tag{4}$$

Given that P_0, P_t, and D_t are already known, the function curve of $V(r)$ is either convex or concave depending on r. It has only one extreme value points either minimum when it is convex or maximum when it is concave. Thus, the minimum value of $V(r)$ can be calculated by solving equation $V'(r)=0$, where $V'(r)$ is the derivative of $V(r)$ with respect to r.

In reality, network operators might only provide a couple of contracts with discrete hedged load/generation percentages. Under such circumstance, the discrete optimal percentages can be found around the continual optimal values. The discrete optimal value must be one of the two discrete values closest to the continual optimal value. The condition for reaching the minimum is that on the left side of the continual optimal point, $V(r)$ decreases with r monotonically, while on the right side $V(r)$ increases with r monotonically.

VI. Case Study

To demonstrate the proposed methodologies, this paper focuses on analyzing the scenarios in which the volatility in network tariffs is caused by uncertain network investment due to the behavior change of network users. For demonstration purposes, it only examines tariff risks for certain demand customers caused by other customers' disconnection and connection.

The proposed tariff hedging is demonstrated on the system given in Fig. 1. D1 and D2 are EDCM customers with the sizes of 5 MW and 10 MW, respectively. There is 40 MW aggregated CDCM customers at busbar 2. The demonstration mainly focuses on tariff analysis for D1 and D2. For the purposes of simplicity, the three circuits are assumed to have the same capacity of 40 MVA, but their investment costs vary: £577 138 for L1, and £288 569 for both L2 and L3. A generally used load growth rate of 1% and discount rate of 6.9% in the U.K. are applied to this example. The projected demand at busbars D1 and D2 in the next 5 years based on 1% growth rate are given in Table I.

If there are no unexpected changes except natural load growth appearing in the system, yearly unit network tariffs for busbars 1 and 2 can be predicted by running network charging and revenue recovery analysis. The values over 5 years are provided in Table II, where site specific fixed adder is used for scaling [24]. The summation of first line unit charges plus the second line unit adders produces the final unit tariffs.

For Year 1, network use factors of all three branches are calculated by diving annual revenue to be recovered of each component (8557.77£/yr, 427.89£/yr, 427.89£/yr) by assumed CDCM customer charges (800£/MW/yr), which produces 10.70, 0.53 and 0.53, respectively. The sum of total network user factor is 11.77. The 20% residual of the port is the EDCM port (23 326.87£/yr) minus revenue recovered (2599.94£/yr) times 20%, producing 4145.38 £/yr. This residual is then divided by the two EDCM customers' sizes (15 MW in total), producing 276.36£/MW/yr. The half of the 80% residual is calculated with EDCM port (23 326.87£/yr) minus revenue recovered (2599.94£/yr) times 80% and divided by 2, producing 8290.77£/yr. The site specific adder for Year 1 is the summation of two different parts: $(8920.77\times 10.70/11.77+920.77/2)/5=2336.49$£/MW/yr, and 2) 276.36£/MW/yr. The final site specific adder is 2612.85£/MW/yr. The similar calculation procedures can be used for other years.

The unit charges for D1 are relatively small due to that L1 is fairly lightly loaded (12.5%) and thus a small injection has little impact on its investment horizon. Therefore, a large proportion of revenue for D1 is recovered by the adders. When the three circuits' utilization increases, network charges become larger and the adders become smaller. It should be noted that although D1 and D2's network charges increase over the 5 years, the unit tariffs for D1 decrease gradually but increase for D2 increase. It is because that the network charges grow very slowly but adders decrease relatively quick as there is more demand on Bus 1 to share the revenue. For D2, the network charges increase at nearly 5.8%, which overwhelm the decrease in adders caused by increasing demand. Therefore, D2 has increasing unit tariffs. The unit tariffs in Table II are used as benchmarks for long-term contract design.

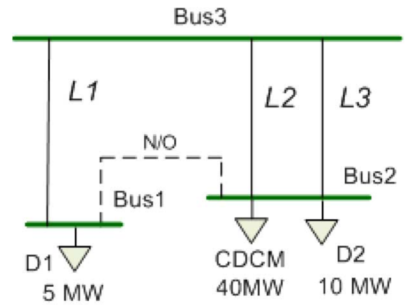

Fig. 1. Three-busbar test system.

TABLE I
Projected MW Demand Over 5 Years (MW)

D_t	Year 1	Year 2	Year 3	Year 4	Year 5
D1	5.0	5.05	5.1	5.15	5.2
D2	10.0	10.1	10.2	10.3	10.41

TABLE II
Projected Unit Results Over 5 Years (£/MW/yr)

P_t	Type	Year 1	Year 2	Year 3	Year 4	Year 5
D1	Charge	0.091	0.095	0.1	0.105	0.111
	Adder	2612.85	2564.79	2515.91	2466.16	2415.47
	Tariff	2,612.94	2,564.88	2,516.01	2,466.27	2,415.58
D2	Charge	259.95	274.98	290.88	307.70	325.49
	Adder	766.27	752.17	737.84	723.25	708.38
	Tariff	1,026.22	1,027.15	1,028.72	1,030.95	1,033.88

TABLE III
TARIFF BILLS FOR FIVE YEARS IN SCENARIO ONE

	Non hedged case (£)	Hedged case (£)
D1	64,123.57	64,146.67
D2	52,510.77	52,489.99

A. Impact of Hedge Contract

In this section, three different scenarios are explored to demonstrate the impact of hedge contract on UoS tariffs for network users. The hedged load percentage and hedged unit price are already known and the task is to calculate the risk premium and final tariffs. In all three examples, 50% demand of D1 and D2 is hedged for 5 years. The hedged unit price is held at 2511£/MW/yr for D1 and 1028£/MW/yr for D2. By using (1), risk premium is calculated as 0.198% for D1 and 0.056% for D2, respectively.

Scenario One: No Network User Comes or Leaves: This is a base case and assumed that no changes appear in the system except natural demand growth, i.e., no new customers come and no existing customers leave. The annual revenue that needs to be recovered is £85 532 from all customers. The revenue is proportionally allocated between EDCM and DCDCM customers according to their sizes. Thus, £23 327 should be recovered from EDCM customers and the remaining £62 205 is from CDCM customers. The projected unit tariffs are given in Table II.

The final total tariffs over 5 years for D1 and D2 are given in Table III, which are the summation of yearly tariffs. Obviously, the tariff difference between hedge and no-hedge contracts is fairly small for both D1 (£23) and D2 (£21). Such small difference proves that if there is no risk or unexpected variations in tariffs, the designed long-term contracts can maintain the patterns of original tariffs. In this case, there is not need for customers to sign up long-term contracts but if they are willing to do so, they will see quite similar total tariffs.

Scenario Two: A New Network User Comes: In this scenario, it is assumed that a new CDCM customer of 4 MW comes to Bus 2 in the second year, leading to a group of 44-MW CDCM customers.

Due to this change, the annual revenue split for both EDCM and CDCM customers change. As the total annual revenue is still £85 532, the EDCM port in the second year decreases to £21 760, which is calculated by $\pounds 85\,532 \times 15.15\ \mathrm{MW}/(15.15\ \mathrm{MW} + 44\ \mathrm{MW})$. While the split for CDCM customers increases to $\pounds 63\,722 (\pounds 85\,532 - \pounds 21\,760)$. From the second year onwards, the revenue ports do not change because both EDCM and CDMC customers increase at the same rate of 1.0%.

As given in Table IV, due to that there are no changes on Bus 1, its unit charges are the same as those in Table II. But, the new connectee has an immediate impact on D2's unit charges, which have a sharp increase of £163 on the second year. It is because that the connectee causes both L2 and L3's utilization to increase, which thus brings forward the two circuits' reinforcement horizons and consequently produces large charges. From the second year onwards, both D1 and D2 have decreasing unit adders as there is more demand to share the revenue. The unit tariffs, however, decrease gradually for D1 but increase for D2. It is due to that the shrinking EDCM port produces smaller adders compared to the tiny increase in network charges. For D2, the increasing unit tariffs are caused by the fact that the increase in network charges overtakes the decrease in site specific adders.

TABLE IV
UNIT RESULTS FOR SCENARIO TWO (£/MW/YR)

P_t	Type	Year 1	Year 2	Year 3	Year 4	Year 5
D1	Charge	0.09	0.095	0.10	0.105	0.111
	Adder	2612.85	2190.04	2133.06	2073.56	2012.42
	Tariff	2612.94	2191.13	2133.16	2073.66	2012.53
D2	Charge	259.95	423.03	447.51	473.41	500.81
	Adder	766.27	635.85	619.03	601.76	584.02
	Tariff	1026.22	1058.89	1066.54	1075.17	1084.83

TABLE V
TARIFF BILLS FOR FIVE YEARS IN SCENARIO TWO

	Non–hedged case (£)	Hedged case (£)
D1	£56,163.83	£60,166.80
D2	£54,203.01	£53,335.43

TABLE VI
UNIT RESULTS FOR SCENARIO THREE (£/MW/YR)

P_t	Type	Year 1	Year 2	Year 3	Year 4	Year 5
D1	Charge	0.09	0.095	0.10	0.105	0.111
	Adder	2612.85	2906.74	2863.30	2819.45	2775.13
	Tariff	2,612.94	2,906.84	2,863.40	2,819.55	2,775.24
D2	Charge	259.95	172.56	182.53	193.07	204.23
	Adder	766.27	862.83	849.93	836.91	823.76
	Tariff	1,026.22	1,035.39	1,032.46	1,029.99	1,027.99

Similarly, summing the yearly tariffs produces the final five-year tariff bills for the two customers, provided in Table V. Customer D1 sees high tariffs when he/she chooses the long-term contract, where the extra payment is approximately £4000. The reason is that this customer's risk premium is positive, which means that he/she needs to pay extra for transferring the risk although his/her actual unit tariffs are lower than the projected ones in Table II. On the contrary, D2 has a drop in 5-year tariffs about £867.58. The reason is that the actual unit tariffs over the period are higher than the predicted ones in Table II. Although his/her risk premium is also positive, the savings in hedging overtakes the extra payment for risk premium.

Scenario Three: An Existing Network User Leaves: In this scenario, it is assumed that an existing 4 MW CDCM customer leaves Bus 2 in Year 2, leading to 36 MW CDCM customers left. Due to this disconnection, the revenue split for EDCM customers increases to £25 137 and for CDCM customers decreases to £60 395 in the second year. For the next three years, the revenue split does not change due to the same reasons in the previous scenario.

As given in Table VI, D1 has an increase in unit tariffs but D2 on the contrary has decreasing unit tariffs. It is because the disconnection of the 4 MW CDCM customer causes the revenue port for EDCM customers to increase from £23 327 to £25 137. Therefore, D1 will see a tariff increase in the second year caused by the increase in site specific adders. From the second year onwards, the EDCM port keeps constant at

TABLE VII
TARIFF BILLS FOR FIVE YEARS IN SCENARIO THREE

	Non-hedged case (£)	Hedged case(£)
D1	71,313.54	67,741.66
D2	52,560.95	52,514.40

TABLE VIII
OPTIMAL HEDGED LOAD PERCENTAGES FOR D1 AND D2

	P_0 (£/MW/yr)	Hedged load percentage r	Total tariff (£)
D1	2,511	20%	64,107
D2	1,028	60%	52,489

£25 137. For the next three years, because both EDCM and CDCM customers increase at the same rate of 1.0%, there is more demand in the system to share the revenue. Therefore, the unit tariffs monotonically decrease for D1. D2 sees decrease in network charges caused by decreasing network utilisation but increase in site specific adders caused by increasing revenue port in the second year. For the next three years, the decrease in adders overwhelms the increase in network charges, causing unit tariffs to monotonically decrease over the next three years.

The final total costs in Table VII demonstrate that D1 can reduce the tariff risk by £3572 and D2 also enjoys a tariff reduction, although the magnitude is only £47.

B. Contract Management for Network Users

Scenario One: Optimal Hedged Load Percentage: This section investigates how network users make decisions in selecting long-term contracts from a group of choices provided by network operators. The problem is to solve the discrete optimisation problem in Section V. Similar to previous three scenarios, the arbitrary hedged unit tariff P_0 is held at 2511 £/MW/yr for D1 and 1028 £/MW/yr for D2. It assumes that operators provide 11 discrete hedged load percentage options ranging from 0 to 100% gaped by 10%.

Table VIII gives the final results, where it can be seen that the optimal hedged load percentages for D1 and D2 are 20% and 60% respectively. Under these values, they will have the least total network tariffs, £64 107 for D1 and £52 489 for D2.

Figs. 2 and 3 show the total tariff variance with different load hedge options for D1 and D2. In both figures, the X axis labels the 11 discrete hedge options from 0 to 100% and the Y axis labels the total tariffs. Obviously, the tariffs are very low for D1 when the hedged load percentage is small, which reach the minimum when the percentage is 20%. Beyond this point, the tariffs increase dramatically with hedged load percentage becoming large. The situation is opposite for D2. The tariffs are very high when hedged load percentage is small, but the values decrease gradually with the rise of hedged load percentage and reach to the minimum at a percentage of 60%.

Scenario Two: Relationship of Hedged Unit Price, Hedged Percentage and Final Tariffs: It is obvious from (2) that hedged unit tariff price and hedged load percentage are two key elements affecting the final total tariffs. Here, more general analysis is conducted to examine the correlation between the two factors and the total final tariffs. For both D1 and D2, the linear discrete optimization in (4) was run to find at what combination of hedged load percentage and hedged price P_0 the minimum tariff can be reached. The hedged load percentage r ranges from 0% to 100% and P_0 varies from the minimum projected unit price to the maximum in Table II. In practice, P_0 should be determined by the DNOs via risk benefit analysis procedures, which is out of the scope of this study. The depicted curves are shown in Figs. 4 and 5, respectively.

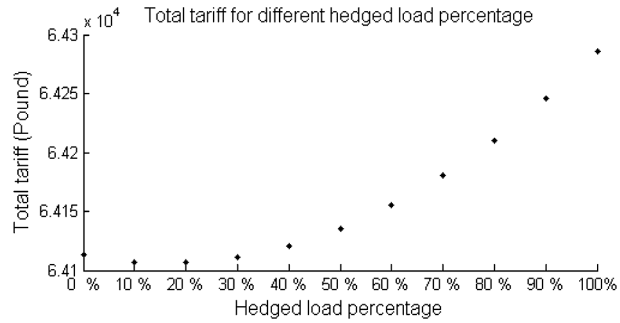

Fig. 2. Total tariff for different hedged load percentage for D1.

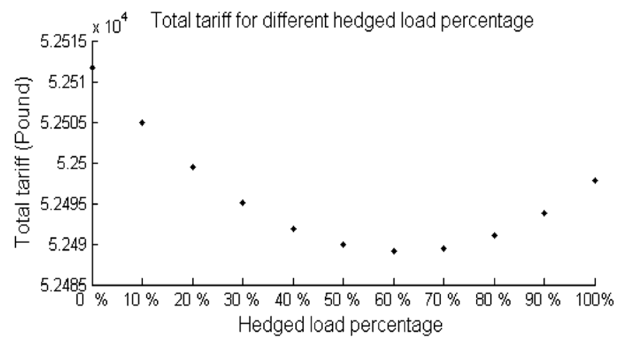

Fig. 3. Total tariff for different hedged load percentage for D2.

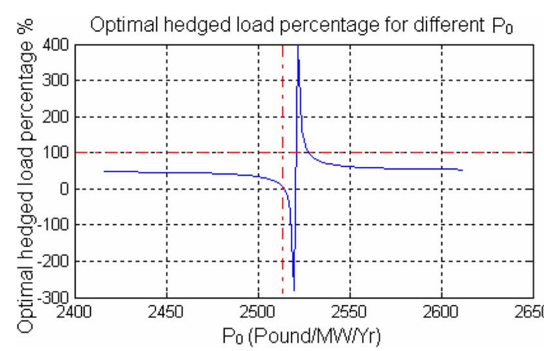

Fig. 4. Relationship between P_0 and r for D1.

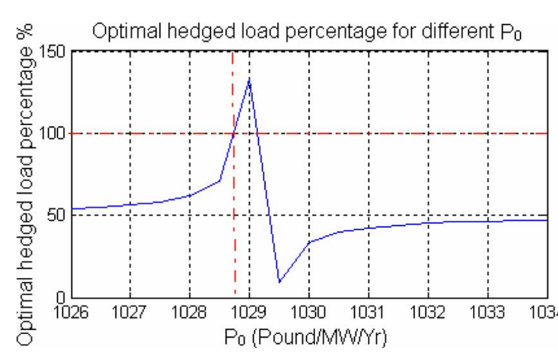

Fig. 5. Relationship between P_0 and r for D2.

In both figures, the X axis labels the hedged price P_0 and the Y axis labels the hedged load percentage. The r with respect to P_0 is calculated by solving the equation $V'(r) = 0$. However, not all the values plotted in the two curves can minimize the optimisation objective function (4). After testing, only the values on the left hand side of the vertical red dash line and below the horizontal red dash line can minimize $V(r)$, subject to $0 \leq r \leq 1$. For the rest values of r, there are two distinct explanations. One is that r falls out of the range $[0, 1]$, which will make the minimum of $V(r)$ appear either when $r = 0$ or $r = 1$, since $V(r)$ monotonically increases or decreases with respect to r in the range $[0, 1]$. The other is that r is between 0 and 1, but at this r, the value of P_0 makes $V(r)$ a concave function not a convex one. This will also make the minimum of $V(r)$ appear either when $r = 0$ or $r = 1$. Neither situation makes sense for customers. Only the values of P_0 that make $V(r)$ a convex function and the minimum values of r locate within $[0, 1]$ are meaningful to customers.

In the sections where the curves show that the tariffs have the minimum values, the two curves display quite different shape. For D1, when hedged unit price P_0 increases, the total tariffs are minimized with the hedged load percentage r decreasing. By contrast, the combination of decreasing r and P_0 produces minimum tariffs for D2.

In summary, the appropriate settings of P_0 in a long-term contract will give customers an option to select an optimal hedged load percentage as a trade-off between total costs and risk. Inappropriate hedged unit tariff P_0 will push customers either not to choose long-term contracts or to be fully hedged. The proposed optimization can assist customers to find the right balance between hedged percentage and hedged prices in order to minimize their total UoS tariffs. The benefits of choosing long-term contracts depend on the degree of the variation of the actual tariffs from the predicted values.

VII. Discussion

Many countries across the world have the similar charging structures like the U.K. for network users to use the networks, such as countries in Latin America [28]. The majority of the distribution UoS charges across the world are a flat rate for each voltage level, i.e., the same prices for the same networks without any locational differences. The UK and Brazil are the first to introduce locational differences in distribution use-of-system tariffs. The key aim is to provide locational messages against the backdrop of substantial growth in distributed generation (DG), providing economic messages to guide their sittings that would incur the least network investment costs.

This paper demonstrated that in achieving better economic efficiency, the locational charges introduce an undesirable side effect—price volatility. A mitigating solution is then proposed for the first time to hedge against the uncertain network tariffs. Hedging volatile network prices has to consider the interplay between the allowed revenue for the whole systems, the revenue pot split between EHV and HV/LV networks, the changes in revenue pots and network utilizations as customers migrate from HV/LV to EHV or vice versa. This provides valuable insights into the balance that academic research must strike—tradeoffs between cost-reflectivity, stability and simplicity. The proposed idea is not applicable to short-run marginal pricing schemes as they reflect short-run costs of energy, congestion and network losses, etc. These costs are not directly linked to network investment costs and not bounded by allowed revenue. Into the future, regulators would increasingly require network investment to be justified through reductions in operational costs rather than simply meeting peak demand, i.e., the trade-offs between investment and operational costs need to be balanced. Then, the proposed approach might be adapted to reflect the balance between short-run operational costs and long-run investment costs.

VIII. Conclusion

In order to reduce the risk in UoS tariffs for network users, this paper for the first time designs long-term contracts to mitigate the risk. It is based on hedging theory to fix the tariffs for part of load/generation over a period of time. Network users should pay for both hedged and non-hedged parts and also an extra part for the risk premium. The paper also develops an optimization decision-making tool to assist network users to economically manage long-term contracts for minimizing UoS tariffs. By analysing the demonstration examples, the following observations can be reached:

1) UoS tariffs for network users have great variations caused by both external and internal elements, which could be detrimental to their business operation. It is essential for network users that the variations could be reduced to some extent by commercial means;
2) The designed long-term contracts can effectively reduce the tariff variation, the degree of which depends on hedged load/generation percentage, hedged prices, and the actual unit tariffs. When risk premium is positive, customers need to pay more for risk reduction, but when it is negative, customers can have a tariff reduction. The gain or loss by signing up the contracts is decided by the three key parameters;
3) The optimal contract management tool can assist network users to choose the most economic contracts, in terms of hedged load/generation percentage and hedged unit prices, to reduce their network tariffs. In some extreme cases, customers might not want to be hedged or want to be fully hedge as the minimum is achieved when the hedged percentage is 0 or 100%.

Future work will incorporate customer risk aversion into hedge contracts and investigate the conditional value at risk for customers who choose differing contracts. Efforts will also be paid to study how regulatory frameworks should be improved in order to encourage both network operators and users to implement the long-term contracts.

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