Transmission Use of System Charging for Differentiating Long-term Impacts from Various Generation Technologies

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***Abstract*—This paper proposes a novel transmission use of system (TUoS) charging method, which is able to 1) acknowledge the trade-offs between short-run congestion cost and long-run investment cost when justifying economic network investment, 2) identify the impacts of different generation technologies on congestion cost and network investment, and 3) translate these impacts into economically efficient TUoS tariffs that differentiate generation technologies. An incremental capacity change from a generator will impact the congestion costs at each branch, which is then translated into the impacts on investment time horizons. The difference in the present values with and without the incremental change for a branch is its long-run incremental cost (LRIC). The final TUoS tariff for this generator is the sum of all LRIC triggered by its capacity increment. The proposed method is demonstrated on a modified IEEE 14-bus system to show its effectiveness over the traditional approach. Results show that it can provide cost-reflective TUoS tariffs for different generation technologies at the same sites by examining their respective impacts on congestion and investment. It thus can incentivize appropriate generation expansion to reduce congestion costs and ultimately network investment cost.**

***Index Terms*—Congestion cost allocation, congestion management, long-run incremental cost, transmission investments, transmission use of system charging.**

NOMENCLATURE

Δc	An incremental capacity change.
ΔCC	Mismatch between CC_T and $\sum \underline{CC}_l$.
ΔPF_l	Difference of power flows on branch l before and after congestion management.
ACC_l	Annual congestion cost for branch l.
AF	Annuity factor.
AIC_l	Annualized investment cost for branch l.
$Assert\_cost_l$	Modern equivalent value for investing branch l.
B_l	Transmission branch l.
CC_l	Congestion cost allocated to branch l.
$\underline{CC}_l$	Initial *CC* allocated to branch l.
CC_l^{in}	Incremental annual congestion cost for branch l, $CC_\mathrm{T} - CC_l^{L-l}$.
CC_l^{L-l}	Annual congestion cost with all branches capacity limits except branch l.
CC_l^{mg}	Marginal annual congestion cost for branch l, only considering branch l's capacity limit.
CC_T	Total annual congestion cost for all branch capacity limits.
C_{Gi}	Generation capacity for generator G_i.
CM	Congestion management.
d	Fixed discount rate, 6.9% per year.
D_ini	Demand at year t_ini.
D_inv	Demand at year t_inv.
G_i	Generator i.
ICRP	Investment cost related pricing.
LRIC	Long-run incremental cost.
$PACC_l$	Present value of annual congestion cost for branch l.
$PAIC_l$	Present value of annualized investment cost for branch l.
P_{Gi}	Production cost for generator G_i.
r	Demand growth rate, 0.5% per year.
ROC	Renewable obligation certificate.
T	Transmission capacity.
t_c	Time period of congestion management.
t_inv	Time horizon of transmission network investment.
t_l	Time period of zero congestion.
TUoS	Transmission use of system.

I. INTRODUCTION

DEREGULATION of the power industry has added difficulties in the forward planning of electricity networks, as network operators have to pay additional efforts to gain sufficient information about the sites and sizes of future generation and demand. These difficulties would exaggerate in the near future due to increasing intermittent renewable generation and demand side responses. In the countries employing similar regulatory structure with the UK, network operators can influence the sites, sizes, and types of future generation and demand through economic incentives, which come in the form of use of system (UoS) charges [1].

Transmission use of system (TUoS) charges are payable by all network users, i.e., generators and suppliers, for their use of transmission systems for transporting electricity from the points of generation to the points of consumption. There are two key purposes of a TUoS charging method [2], [3]:

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1) to recover network operators' fixed costs in operation, maintenance and investment;
2) to provide forward-looking, economically efficient signals for both existing and future generation and demand, aiming to promote efficient use of existing networks and cost-reflective development of future networks.

Many transmission charging methods have been designed for recovering embedded costs and allocating the existing network's fixed costs among network users in proportion to their "extent of use" of networks [4]–[8]. These methods differ in terms of their measurement of "extent of use." However, they cannot provide forward-looking signals to discriminate between network users, who cause additional network reinforcement or expansion, and those that reduce or delay otherwise required network updates [9].

Incremental/marginal charging methods have also been introduced to provide forward-looking signals, differentiating users in their impacts on short-term and long-term network costs [7], [9]–[16]. Short-run incremental or marginal charging (SRIC/SRMC) methods evaluate the additional operational costs typically caused due to network constraints. Long-run incremental or marginal charging (LRIC/LRMC) methods reflect incremental network investment costs as a result of a marginal or incremental generation/demand change, which is considered to be more economical for allocating network fixed costs. These methods typically rely on a two-step approach [7], [10], [11], [13], [15], [16]. First, they determine network planning for a future time based on projected future generation and demand pattern. Subsequently, the costs are allocated to the current and future network users. These methods passively react to forecasted future generation and demand, rather than proactively affect their siting and sizing. Also, future generation/demand predictions are far from certain, resulting in wholly inappropriate charges.

Investment cost related pricing (ICRP) method, which has been employed in the UK since 1993, directly links network investment to nodal injection [9]. It employs a simple proxy to produce locational tariffs, representing the cost of providing transmission capacity to cater for an additional generation or demand at each node [17]. However, ICRP is too simplistic for two reasons [9], [14], [18]. First, it assumes that existing networks are fully utilized and any additional power flow as a result of nodal increment will immediately trigger network reinforcement. It thus does not recognize the existence of spare network capacity and congestion management. Second, it charges network users based on a single scenario of system peak. Thus, it cannot distinguish conventional generation and intermittent renewable generation, causing significant cross-subsidies for a low carbon power system.

The vast majority of existing network charging methods do not consider the trade-offs between short-run operational costs and long-run investment costs. Paper [19] provides the first attempt to introduce the concept to transmission charging. This preliminary study employs a LRIC approach to produce transmisison charges via examing network user's impact on the investment time horizon. Although, LRIC can distinguish the contribution to system congestion from a location, it cannot recognize the impact of different generation technologies at the same location. This defect may lead to distorted and inefficient TUoS tariffs, and particularly in the case of intermittent renewables, can pose significant barriers for their integration.

This paper develops an innovative and practical TUoS charging method that can differentiate the contribution to congestion from diverse generation technologies, providing economically efficient signals for intermittent and conventional generation to incentivize efficient development of a low carbon power system. The main contributions are that:

1) The proposed method acknowledges the trade-offs between congestion cost and investment cost in investing transmission networks. It recognizes TSO's capability in congestion management and thus network investments are not required until network reinforcement becomes cheaper than congestion management.
2) It recognizes the contribution to the trade-offs between congestion and investment from different generation technologies. This is particularly important for a low carbon power system with significant intermittent generation, which uses the networks very differently from conventional generation. None of existing charging methods can differentiate the contribution from different generation technologies, but this method addresses this important gap.

The rest of this paper is organized as follows: Section III introduces the proposed TUoS charging method and explains the principles of differentiating generation technologies. In Section IV, congestion cost calculation is explained and congestion cost allocation method is presented. Section V introduces the demonstration system and simulation process. Section VI provides results and discussion. A comparison between ICRP method and the proposed method is given in Section VII. Finally, conclusions are drawn in Section VIII.

II. PRINCIPLES OF THE PROPOSED METHOD

The fundamental principles of the proposed TUoS charging method are first introduced. Then, how to differentiate various generation technologies is explained.

A. Long-run Incremental Cost for Transmission Networks

Economy driven transmission investments are justified based on the trade-offs between congestion cost and investment cost. Congestion cost is shaped by many factors, from demand side, network side, and generation side. The proposed method employs a simple but reflective model to capture the key features in investing transmission networks. It does not assume future generation and network expansion, but only requires information pertaining to existing generation mix, transmission network, and demand. The conceptual system in Fig. 1 is employed to explain the proposed idea.

To address occurrences of congestion, expensive generators are assumed to be located close to demand (right-side of Fig. 1), while cheap generators are located far away from demand (left-side of Fig. 1). In economic dispatch, power is transferred over the transmission line to meet demand in the load center. Before congestion appears, expensive generators (generator 1, 2, and 3) are not dispatched. The situation of zero congestion

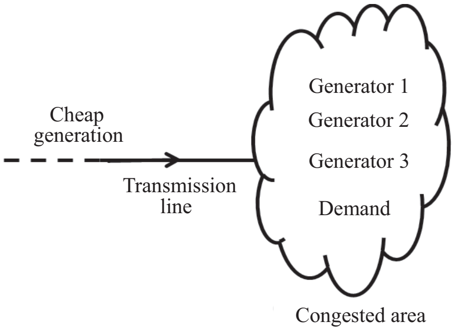

Fig. 1. Conceptual power system.

lasts for time t_l. Demand exceeding network capacity causes congestion and congestion management is executed to dispatch expensive generators. Economy driven transmission network investment is not executed until the annual congestion cost (*ACC′*) in a future time exceeds the annualized investment cost (*AIC*). The situation of congestion management lasts for time t_{c}. The time horizon of transmission network investment (t'_{inv}) is

$$t_{\mathrm{inv}} = t_l + t_{\mathrm{c}} \quad \text{when } ACC \geq AIC. \tag{1}$$

Given the fixed discount rate d, $PAIC_l^{t_{\mathrm{inv}}}$ for line l in year t_{inv} is

$$AIC_l = \frac{Assert\_cost_l}{AF} \tag{2}$$

$$PAIC_l^{t_{\mathrm{inv}}} = \frac{AIC_l}{(1+d)^{t_{\mathrm{inv}}}} \tag{3}$$

where *AF* (annuity factor) represents the ratio between AIC_l and $Assert\_cost_l$, reflecting the time value of money.

An incremental capacity change (Δc) from one network user (generator or demand) will impact the *ACC* of each branch, and the time horizon to invest in the branch (from t_{inv} to year t'_{inv}). Due to Δc, the time horizon of network investment becomes to

$$t'_{\mathrm{inv}} = t'_l + t'_{\mathrm{c}} \quad \text{when } ACC \geq AIC. \tag{4}$$

These changes are presented in Fig. 2. t_l, t_{c}, and t_{inv} are plotted in blue, red and green respectively. Solid lines represent the case without Δc. Dashed lines represent the case with Δc. The purple line stands for AIC_l, which is compared with ACC_l to decide t_{c}, and t_{inv}.

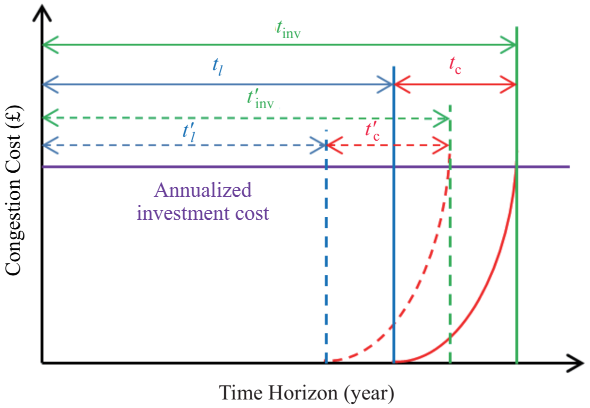

Fig. 2. Time horizon of transmission network investment.

Δc also changes $PAIC_l^{t_{\mathrm{inv}}}$ to $PAIC_l^{\prime t_{\mathrm{inv}}}$.

$$PAIC_l^{\prime t_{\mathrm{inv}}} = \frac{AIC_l}{(1+d)^{t'_{\mathrm{inv}}}} \tag{5}$$

The difference in the present values with and without Δc is the long-run incremental cost (LRIC) for branch l.

$$\begin{aligned} LRIC_l\,(\Delta c) &= PAIC_l^{\prime t_{\mathrm{inv}}} - PAIC_l^{t_{\mathrm{inv}}} \\ &= AIC_l \left(\frac{1}{(1+d)^{t'_{\mathrm{inv}}}} - \frac{1}{(1+d)^{t_{\mathrm{inv}}}} \right) \end{aligned} \tag{6}$$

The total TUoS tariff for this network user is the summation of all LRIC charges triggered by its incremental change.

$$\text{total TUoS tariff} = \frac{\sum_l \mathrm{LRIC}_l}{\Delta c} \tag{7}$$

B. Differentiating Diverse Generation Technologies

In the proposed method, diverse generation technologies are differentiated by their production costs and availability, which determine their impacts on congestion costs at each branch. A renewable generation pattern is required to recognize their intermittent characteristics. The conceptual system in Fig. 1 is employed to explain the principle for differentiating generation technologies.

The production cost for each generation technology ($P_{G_C}, P_{G_1}, P_{G_2}, P_{G_3}$) is assumed to be linear, and it is assumed that $P_{G_C} < P_{G_1} < P_{G_2} < P_{G_3}$. Their installed capacity are expressed as $C_{G_C}, C_{G_1}, C_{G_2}, C_{G_3}$. C_{G_C} is assumed to be large enough to meet demand individually. With these assumptions, congestion occurs when demand exceeds transmission line capacity (T), in which case expensive generators (G_1, G_2 and G_3) are dispatched to meet the part of demand above T. *CC* is determined by the quantity of demand above T and generators' adjustment costs, which are related to their production costs.

An incremental capacity change (Δc) from G_1 will replace one unit from G_2 (when $(T + C_{G1}) < D < (T + C_{G1} + C_{G2})$) or G_3 (when $D > (T + C_{G1} + C_{G2})$) during congestion situation. Δc will reduce *CC*, thus defer network investment. Likewise, an incremental capacity change (Δc) from G_2 will also reduce *CC* and defer network investment. However, Δc from G_1 will defer network investment into future further than that from G_2 as G_1 is cheaper generation than G_2. Thus, G_1 deserves a larger incentive than G_2. Therefore, G_1 and G_2 are differentiated.

Cheap generation G_{Gc} is assumed to be based on one generation technology for simplification. In reality, it may be a mix of different technologies, but the same philosophy is applicable. As the marginal generator, LRIC for G_3 cannot be calculated in a similar way as G_1 and G_2, since its capacity may not be fully utilized and an incremental change from C_{G3} has no influence on *CC*. However, in reality, the marginal generators for different times around the year are different, and it is still feasible to calculate LRIC for all generators.

III. CONGESTION COST CALCULATION AND ALLOCATION

Based on the framework of the proposed method shown in Section III, this section presents how to calculate and allocate congestion costs, facilitating the comparison between congestion cost and investment cost on the branch level.

A. Congestion Cost Calculation

In transmission networks, congestion management (CM) is a better alternative than passively investing in networks or curtailing generation or demand [20]. Technical CM measures include switching bus boosters, changing transformer taps, restructuring network topology, etc. Commercial CM measures may require generation re-dispatch, in which generators are required to increase or decrease their outputs. Responsive demand can also help in CM. CM aims to eliminate network congestion with a minimum adjustment cost (*CC*), satisfying generation and network constraints.

In the UK, the balancing market handles transmission congestion [21]. In this market, generator/demand is required to submit its bid/offer prices to the transmission system operator (TSO). The offer price represents the unit payment from the TSO to generation/demand at which they are willing to increase/decrease their output/consumption. The bid price represents the unit payment to the TSO from generation/demand at which they are willing to decrease/increase their output/consumption.

In the UK balancing market, congestion cost is the difference between the payment to accepted offers and the payment from accepted bids.

$$\mathrm{CC} = \sum \text{Payment to offers} - \sum \text{Payment from bids} \tag{8}$$

B. Congestion Cost Allocation

Research that explores congestion cost allocation [5], [22], [23] ranges from uniform allocation method to power transfer distribution factor based sensitivity method and aggregated allocation method to Aumann-Shapley value allocation method. This paper adopts the allocation method from [22] to allocate *CC* for the whole system to branches. The adopted method is originated from "gaming theory" and ensures acceptable accuracy [22].

Fig. 3 gives the flowchart of the adopted *CC* allocation method.

First, CC_{T}, which is total annual congestion cost with all branch capacity limits, and CC_l^{L-l}, which is total congestion cost without capacity limits from branch l, are calculated. CC_{T} minus CC_l^{L-l} gives CC_l^{in}, which is incremental CC for branch l. Afterwords, CC_l^{mg}, which is marginal CC for branch l, is calculated by only considering the capacity limit from branch l. Then, $\underline{CC_l}$, which is the average of CC_l^{in} and CC_l^{mg}, is assigned as the initial *CC* allocated to branch l. Finally, CC_l is corrected via eliminating the mismatch (ΔCC) between CC_{T} and $\sum \underline{CC_l}$.

$$CC_l = \underline{CC_l} + \Delta CC \times \frac{\Delta PF_l}{\sum \Delta PF_l} \tag{9}$$

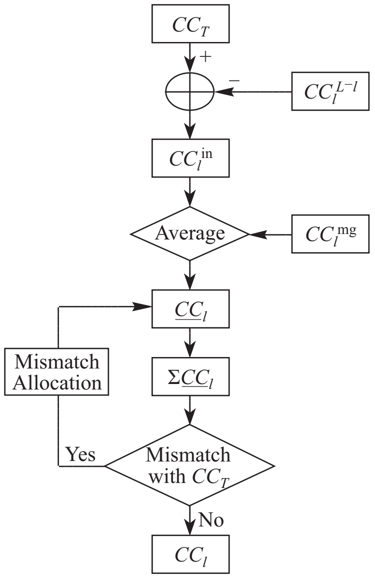

Fig. 3. Flowchart for congestion cost allocation.

IV. DEMONSTRATION SYSTEM AND SIMULATION PROCESS

A modified IEEE 14-bus system [24] shown in Fig. 4, is employed to demonstrate the proposed method.

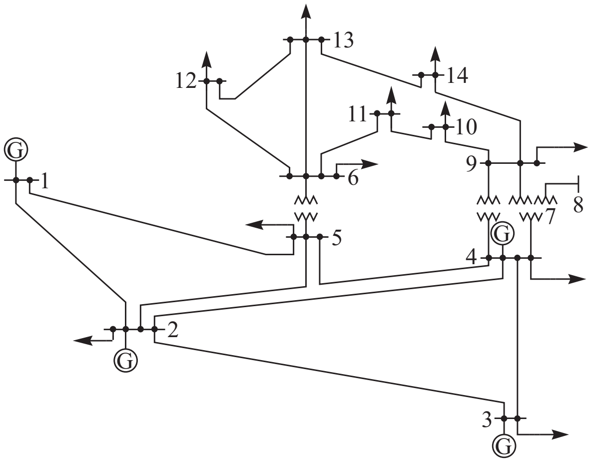

Fig. 4. Modified IEEE 14 bus system.

A. Demonstration System Parameters

In order to illustrate the effectiveness of proposed method in differentiating generation technologies, different combinations of generation technologies are considered at nodes 1–4. Geneation parameters are given in Table I.

The production costs (P_{Gi}) are set to typical values from [25]. Generators' bid/offer prices are set to be a ratio of their production costs. These ratios evaluated from the empirical data of generator behaviors in the balancing market, widely used for market simulation and analysis [18]. Nuclear generator G_1 has inflexible generation, so it does not participate into the balancing market. Conventional generators G_2, G_4–G_6 have −0.6 ratio to P_{Gi} for bids and 1.6 ratio to P_{Gi} for offers. Wind generators G_3, G_7 and G_8 have low

TABLE I
GENERATOR PARAMETERS

Node	Generator	Technology	Capacity (MW)	P_{Gi} (£/MW)	Bid Ratio to P_{Gi}	Offer Ratio to P_{Gi}
1	G_1	Nuclear	50	6.5	-	-
	G_2	Coal	100	35.73	-0.6	1.6
	G_3	Wind	30	0.1	500	-
2	G_4	Coal	50	39.99	-0.6	1.6
	G_5	Gas	50	45.23	-0.6	1.6
3	G_6	Gas	30	47.68	-0.6	1.6
	G_7	Wind	20	0.1	500	-
4	G_8	Wind	10	0.1	500	-

P_{Gi} to reflect their priorities in generation dispatch. Their bid prices are set as 500 to avoid curtailment, representing the value of trading renewable obligation certificate (ROC) (£50/MWh in this paper). There are no offer prices for wind generators as they cannot independently increase their outputs.

Generation expansion is not necessary in the foreseeable future. Conventional generators are assumed to be available throughout the whole year. Wind generation is assumed to follow the historical 2012 UK wind generation pattern, obtained from [26].

Network parameters are given in Table II. Network impedance is available from [24]. Transmission losses are not considered. Branch capacity limits are set based on the method proposed in [27], which is able to consider $N-1$ contingency. Constraints are considered to reflect congestion for the modified IEEE 14-bus system. The discount rate d is 6.9% per annum and assets lifespan as 45 years [28], generating an AF of 0.073.

TABLE II
NETWORK PARAMETERS

Branch	From Bus	To Bus	Length (miles)	Capacity (MW)	Investment Cost (£10^5)	AIC (£10^5)
B_1	1	2	150	115	34.4	2.50
B_2	1	5	200	55	43.9	3.19
B_3	2	3	250	55	41.1	2.99
B_4	2	4	250	50	24.9	1.81
B_5	2	5	150	50	14.9	1.09
B_6	3	4	100	20	3.98	0.289
B_7	4	5	100	50	9.97	0.724
B_8	4	7	0	40	0	0
B_9	4	9	0	30	0	0
B_{10}	5	6	0	50	0	0
B_{11}	6	11	50	15	0.75	0.054
B_{12}	6	12	80	15	1.20	0.087
B_{13}	6	13	100	25	2.49	0.181
B_{14}	7	8	10	20	0.20	0.015
B_{15}	7	9	0	40	0	0
B_{16}	9	10	30	15	0.45	0.033
B_{17}	9	14	80	20	1.60	0.116
B_{18}	10	11	30	15	0.45	0.033
B_{19}	12	13	50	15	0.75	0.054
B_{20}	13	14	80	15	1.20	0.087

TABLE III
DEMAND PARAMETERS

Node	Load (MW)	Node	Load (MW)
1	0	8	0
2	21.7	9	29.5
3	94.2	10	9
4	47.8	11	3.5
5	7.6	12	6.1
8	11.2	13	13.5
7	0	14	14.9

Load at each node during system peak for the current year is given in Table III.

Demand is assumed to increase with a fixed rate every year:

$$D_{\text{inv}} = D_{\text{ini}} \times (1+r)^{t_{\text{inv}}} \tag{10}$$

where r is chosen 0.5% per annum [29]. The annual demand variation follows historical UK demand patterns in 2012 [26], from 35.91% to 100% of the peak demand. Zero elasticity is assumed for demand, assuming that they do not participate in the balancing market.

B. Simulation Process

The calculation of ACC simulates the whole year system operation on 0.5 h basis and thus it is the summation of CC of 17,568 (366 × 48) time intervals. The calculation employs the economic dispatch function in the Matpower package [30]. One simulation includes two cases: one without considering branch capacity limits and the other with considering branch capacity limits. The difference of a generator's outputs in these two cases represents the quantity of bid/offer accepted by the TSO, which are then multiplied by their bid/offer prices to obtain the congestion costs for the whole system. Congestion cost allocation is achieved by extending the branch capacity limits in the second case via the adopted CC allocation method.

Investment time horizons and TUoS tariffs are determined via Matlab programming. An initial time variable is first assumed, and branch congestion costs for this future time are calculated. Based on the difference between branch ACC and *AIC*, the time variable is increased or decreased proportionally. Until branch ACC equals to *AIC*, the time variable is saved as the determined time horizon. Afterwards, an incremental capacity increase is added and a new investment time horizon is determined. Finally, TUoS tariffs are determined as the difference in the present values of branch reinforcement under the two time horizons.

V. RESULTS AND DISCUSSION

A. Demonstration System Operation Condition

The time-varying demand causes the power flow along network branches to change every hour, thus reflecting the *CC* allocated to them. In current year (t_{inv} = 0), the power flows on branches B_1–B_5 and B_7 may exceed their capacity limits, and thus will be congested. The other branches are never congested.

The generators' load factors at $t_{\text{inv}} = 0$ are given in Table IV. Nuclear generator G_1 has unity load factor. Coal-fired generators G_2 and G_4 are the second cheapest generation after nuclear, and therefore have higher load factor than G_5 and G_6. Although P_{G5} is smaller than P_{G6}, G_6 has higher load factor than G_5 due to constraints. Wind generators G_3, G_7 and G_8 have the same load factor as they follow the same pattern.

TABLE IV
GENERATOR LOAD FACTOR AT $t_{\text{inv}} = 0$

Generator	G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8
Load Factor	1.0	0.83	0.29	0.18	0.004	0.014	0.29	0.29

At $t_{\text{inv}} = 0$, *ACC* for the whole system is £264,000. *CC* allocated to B_1–B_5 and B_7 (CC_1–CC_5 and CC_7) are £32,000, £105,000, £87,000, £23,000, £97, and £16,000 respectively.

Fig. 5 gives the CC_1–CC_7 for the next 20 years. The results show that only CC_2–CC_4 and CC_7 will hit the relevant branches' *AIC*. Therefore, incremental changes from network users only influence the time to invest in B_2–B_4 and B_7, and TUoS tariff only come from the changes in present values for investing B_2–B_4 and B_7.

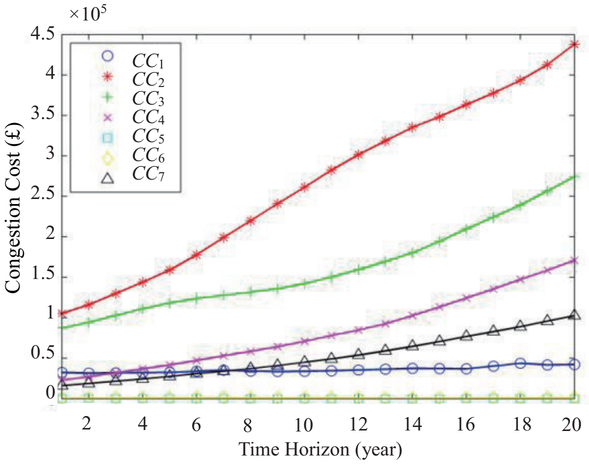

Fig. 5. *CC* for B_1–B_7 over next 20 years.

B. Impacts on Time Horizon of Network Investment

The initial t_{inv} for B_2–B_4 and B_7 are 15.62, 19.90, 21.56, and 15.78 years, respectively. The investment time change due to Δc from each generator is given in Table V.

TABLE V
INVESTMENT TIME CHANGE FOR B_2–B_4 AND B_7

Incremental Capacity Change from	Investment Time Change for B_2 (year)	Investment Time Change for B_3 (year)	Investment Time Change for B_4 (year)	Investment Time Change for B_7 (year)
G_1	−2.33	1.75	0	−1.57
G_2	−2.15	1.75	0	−1.57
G_3	−0.73	0.28	0	−0.24
G_4	0.52	−0.21	−0.41	−0.24
G_5	0.04	0.13	−0.05	−0.24
G_6	−0.44	0.13	−0.05	−0.24
G_7	0.24	1.26	0.34	0.54
G_8	0.98	0.40	0.65	1.06

Positive investment time change means deferred network investment whilst negative investment time change means advanced network investment. Furthermore, if the absolute value of the changes is larger, it means that the expansion from this generator can defer the investment further or advance the investment earlier.

Table V shows that the proposed method is able to effectively identify impacts of generation technologies on long-term network investments.

C. TUoS Tariffs

Fig. 6 depicts the TUoS tariffs for G_1–G_3 at node 1. Incremental increases from G_1–G_3 advance the investment horizon of B_2 and B_7; thus they face positive tariffs. Incremental increases from G_1–G_3 defer the investment horizon of B_3, and thus they face negative tariffs. Incremental increases from G_1–G_3 have no influence on the investment horizon of B_4, and thus TUoS tariff from B_4 is zero.

Moreover, G_1 (−2.33 years) advances the investment of B_2 earlier than G_2 (−2.15 years). Therefore, G_1 is exposed to larger tariffs. The same philosophy applies when generators defer investment. The proposed method can successfully translate the impact of different generation technologies at the same location on network investment into efficient TUoS tariffs.

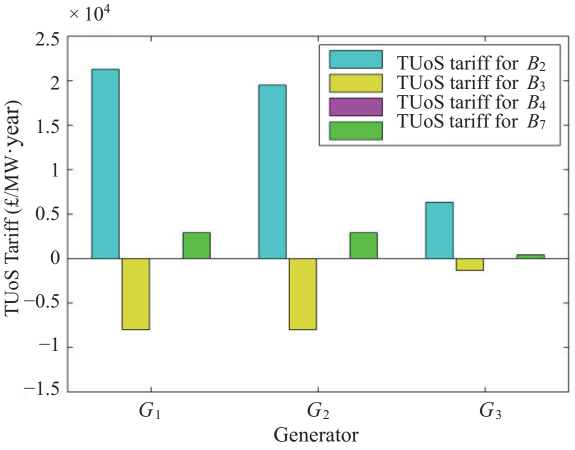

Fig. 6. TUoS tariffs for generators at node 1.

Figs. 7 and 8 show the total TUoS tariffs for generation and demand, respectively. These tariffs reflect individual network user's influence on the whole system.

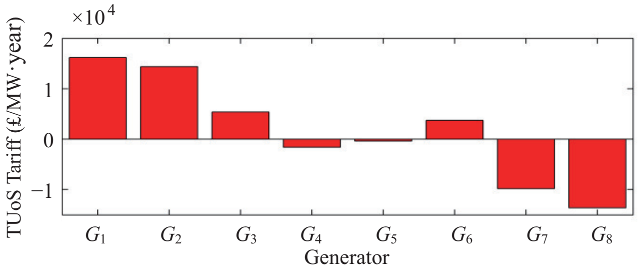

Fig. 7. Total TUoS tariffs for generation.

At node 1, wind generation G_3 faces lower tariffs than conventional generation G_1 and G_2. G_4 and G_5 connected at node 2 have different negative tariffs. G_6 connected at node 3 pays positive tariffs, while G_7 at the same location sees negative tariffs. Wind generation G_8 sees a larger incentive. Clearly, the proposed method can differentiate generation

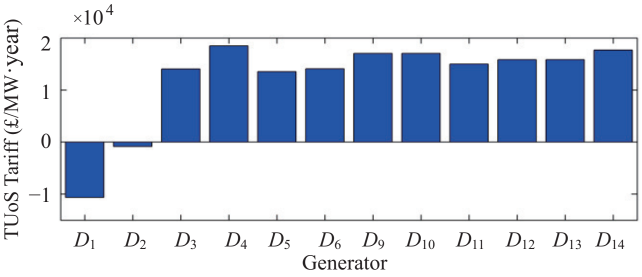

Fig. 8. Total TUoS tariffs for demand.

technologies in the same locations. Under other considerations such as fuel and land availability, future generation will be attracted to locations with lower positive tariffs or locations with negative tariffs.

The TUoS tariffs for demand at node 1 and 2 are negative. Future demand will be attracted to these locations, where large cheap generation is connected. TUoS tariffs for demand at node 3–6, 9–14 are positive. Future demand at these locations is therefore suppressed.

From Figs. 7 and 8, it can be concluded that the proposed method can provide efficient incentives to guide appropriate behaviors of future generation and demand for reducing system congestion cost and ultimately investment cost.

VI. COMPARISON WITH INVESTMENT COST RELATED PRICING (ICRP) METHOD

The Investment Cost Related Pricing (ICRP) method used to formulate transmission network charges in Great Britain [17] has two main shortcomings. First, it assumes that existing transmission system is fully utilized and any additional injections will thus require immediate network investment. Therefore, there is no cognition of congestion management, and congestion is not factored into TUoS tariffs. Second, generation is scaled uniformly to meet system peak demand in tariff calculation. These assumptions result in the same tariffs at a location, irrespective of generation technologies employed. The tariffs are thus not cost-reflective, especially in low carbon scenarios, causing significant cross-subsidies. The proposed method presents remarkable merits to overcome these two defects.

A comparison between the ICRP method and the proposed method is demonstrated on the modified IEEE 14-bus system. Only TUoS tariffs gained through economic pricing are compared. The imbalance between the revenue collected from those indicative charges and the maximum allowed revenue is covered through revenue recognition process, which is out of the scope of this paper and thus not considered.

The unit cost and safety factor for LRIC method are chosen as £12.5/MW·mile·year and 1.8 [31]. Node 8 is the reference node. Expansion factors are given in Table VI.

TABLE VI
EXPANSION FACTORS FOR DEMONSTRATION SYSTEM

Branch	B_1	B_2	B_3	B_4	B_5	B_6	B_7	B_8	B_9	B_{10}
Expansion Factor	1	2	1.5	1	1	1	1	0	0	0
Branch	B_{11}	B_{12}	B_{13}	B_{14}	B_{15}	B_{16}	B_{17}	B_{18}	B_{19}	B_{20}
Expansion Factor	0.5	0.5	0.5	0.5	0	0.5	0.5	0.5	0.5	0.5

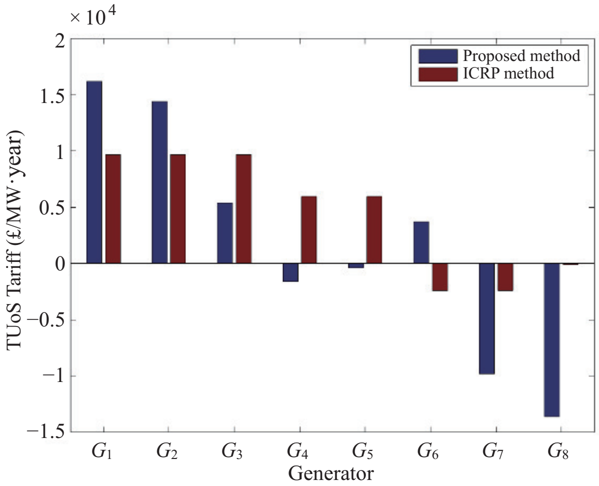

Fig. 9. Comparitive TUoS tariffs from ICRP and the proposed method.

Fig. 9 compares the TUoS tariffs from ICRP and the proposed method. It shows that ICRP tariffs fail to differentiate generation technologies. At node 1, renewable generation G_3 faces the same tariff with conventional generation G_1 and G_2. Under the proposed method, the tariff for G_3 is nearly half of those for G_1 and G_2. Therefore, the ICRP tariffs impede the development of renewable generation at node 1. At node 2, ICRP method charges G_4 and G_5, while the proposed method incentivizes them. Tariff for G_6 also reverses. This is because the ICRP method does not incorporate congestion into TUoS charges, leading future generation to inappropriate locations and consequently incurring more serious congestion. Both methods offer negative tariffs for G_7 and G_8, but ICRP tariffs are much smaller than those from the proposed method. It means that ICRP tariffs provide insufficient incentives for the development of renewable generation at nodes 3 and 4.

Fig. 10 compares TUoS tariffs from ICRP and the proposed method for G_3 and G_7 for the next 10 years. ICRP tariffs remain relatively steady, but tariffs from the proposed method

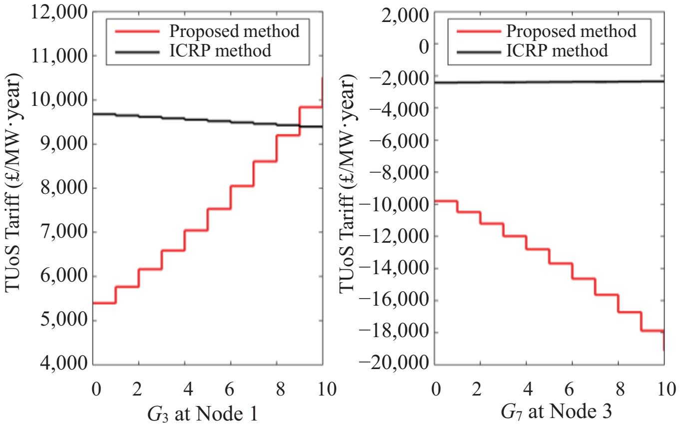

Fig. 10. TUoS tariffs of G_3 and G_7 for next 10 years.

show a continuous adjustment every year, reflecting the extent of system congestion. At node 1, the increasing tariffs might prevent more generation to be deployed, and thus congestion is not aggravated. At node 3, the growing incentive will attract more renewable generation and help to defer costly investment.

VII. CONCLUSION

This paper presents a novel transmission use of system (TUoS) charging method, which is able to identify the impacts of different network users on short-run congestion cost and their consequential impacts on investment cost. These impacts are translated into efficient TUoS tariffs through a long-run incremental cost (LRIC) approach that differentiates renewable from conventional generation.

The benefits of introducing the proposed method are highlighted via a comparison with the existing ICRP method. The proposed TUoS charging method gives positive tariffs for congestion contributors and negative tariffs for congestion mitigators. The magnitude of TUoS tariff reflects the extent of advancing or differing network investment. Different generation technologies at the same locations are differentiated, reflecting their respective contribution to congestion and investment cost. With changes in demand and generation, TUoS tariffs from the proposed method continuously vary every year to reflect the extent of system congestion. The tariffs will not only provide efficient incentives to proactively attract future generation or demand to appropriate locations, but also reduce congestion cost and ultimately network investment cost. Critically, these tariffs will remove cross-subsidies between renewable and conventional generation, and will in turn enable the efficient development of a low carbon system.

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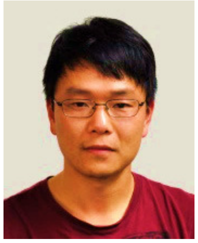

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