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Exploratory Analysis on the Impact of Grid Tariffs in Transmission Expansion Planning

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***Abstract*—The cost of grid tariffs is expected to rise and account for an ever-increasing share of electricity consumers' invoices. Hence, it is imperative to factor these costs in when modelling electricity demand behaviour in a market-driven environment. Accurate demand profiles are essential for optimising transmission expansion planning (TEP) as an accurate representation of electricity demand profiles aids in finding the most beneficial expansion plan. Common TEP formulations in the literature do not include the costs accumulated by grid tariffs. This paper proposes a revised problem representation incorporating a version of grid tariffs in the objective function of TEP optimisation. An analysis is carried out to estimate the sensitivity of the planning strategy to different ratios of grid tariffs to generation costs. It could be concluded that as the grid tariffs are of the same magnitude as the generation costs, the optimal planning strategy foresees to retrofit lines facilitating local generation over grid-sourced electricity. If the grid tariff is further increased, there will be no significant deviation in the expansion plan from the optimal expansion plan generated at grid tariff to generation cost parity.**

***Index Terms*—Grid Tariff, Transmission Expansion Planning**

NOMENCLATURE

Indices

d	Index for demands
g	Index for generation units.
l	Index for lines.
n	Index for nodes.
t	Index for time window.

Sets

D	Index set of demands.
G	Index set of generators.
L	Index set of existing lines.
L'	Index set of candidate lines.
N	Index set of nodes.
T	Index set of time windows (hours of the day).

Parameters

$a_{g,n}$	Parameter linking generator g to node n.
$b_{d,n}$	Parameter linking demand d to node n.
$A_{l,n}$	Adjacency matrix of existing lines.
$A'_{l,n}$	Adjacency matrix of candidate lines.
c_g^{gen}	Costs for power from generator g.
c_l^{line}	Costs for constructing candidate line l.
c_n^r	Cost for load curtailment at node n.
c_l^{GT}	Cost of grid tariff of line l.
$D_{l,l}$	Existing line susceptance matrix.
$D'_{l,l}$	Candidate line susceptance matrix.
f_l^{max}	Thermal power limit of existing line l.
$f_l'^{max}$	Thermal power limit of candidate line l.
M_l	Big M constant of candidate line l.
p_g^{max}	Maximum power output by generator g.
p_g^{min}	Minimum power output by generator g.
θ_n^{max}	Maximum voltage angle of node n.

Variables

$d_{d,t}$	Power consumption of demand d at time t.
$f_{l,t}$	Power flow on existing line l at time t.
$f_{l,t}^+$	Positive power flow on existing line l at time t.
$f_{l,t}^-$	Negative power flow on existing line l at time t.
$f'_{l,t}$	Power flow on candidate line l at time t.
$f'^+_{l,t}$	Positive power flow on candidate line l at time t.
$f'^-_{l,t}$	Negative power flow on candidate line l at time t.
$p_{g,t}$	Power provided by generator g at time t.
$r_{n,t}$	Load curtailment at node n at time t.
x_l^{line}	Binary investment decision for candidate line l.
$\theta_{n,t}$	Voltage angle of node n at time t.

I. INTRODUCTION

Due to emerging and existing net-zero policies around the globe, the amount of electrical power needed due to the electrification of several industry sectors is expected to experience a strong growth [1]. This presents an ever-increasing challenge for network operators in terms of long-term planning, as modelling electricity demand is a critical element in transmission expansion planning (TEP). This planning comprises the challenge of determining the most advantageous plan for expanding the transmission network whilst facilitating growing electricity demand, providing access to low-cost power generation and meeting various other conditions while keeping the expansion costs down. Since a thorough expansion plan includes not only investment decisions but also an operational analysis, the uncertainty associated with the consumption behaviour of market participants within the network can lead to fluctuations in the TEP result.

Electricity consumption behaviour is dependent on operational expenses, thus it is essential to represent real-world economic conditions to achieve an accurate model. The grid tariff does represent a significant share of the final electricity bill, therefore presenting a factor of impact on the consumer's demand profile. It is the fee an electricity consumer is charged for grid-sourced power. Variations in grid tariffs impact electricity demand patterns, opening the possibility of shifting the economic equilibrium between local generation and grid-sourced power. As a result, the interplay between generation costs and grid tariffs introduces substantial uncertainty about how consumers might respond to these price signals. This uncertainty propagates into the planning process, making it challenging to design a robust and cost-effective transmission expansion strategy.

The share of grid tariff expenses on the total electricity bill for European households ranges between 20% and 50% [2]. According to [3], German distribution system operators' grid tariffs featured a significant range of 9.6-16.26¢/kWh in 2024. For large consumers in Austria, depending on their network level connection, the grid tariff fees can accumulate to 40% of the final electricity bill [4], further showcasing the importance of factoring in grid tariffs in TEP. In addition, with the beginning of 2025, German grid operators are required to offer variable grid tariffs due to new/upcoming regulation [5], displaying another challenge for accurate demand modelling. Finally, the grid tariff fees are projected to increase. These costs already represent a considerable share of the electricity bill and this trend is projected to continue to increase in the near future. According to several regulatory agencies, this change stems from transmission system operators raising costs to fund the increasing expenses of grid expansion and to discourage high peak consumption until the grid infrastructure is sufficiently developed [6], [7]. This will therefore assist in higher accuracy in modelling consumer behaviour.

In many European countries, the grid tariff charges consist partly of energy consumption and partly of the peak power demand for electricity. The power component is based on the arithmetic mean of the highest quarter-hourly power consumed per month over the contract duration (maximum of a year), whereas the other component is proportional to the energy consumed in that same period. However, households, which are generally connected to the low-voltage grid, only pay a fixed amount regarding the peak power component, as not all consumers are equipped with smart meter technology to measure the power consumption profile.

The effect of increased grid tariffs on consumer behaviour and TEP has been addressed in several contributions. In [8] the effect of different grid tariff structures (individual peak pricing, dynamic peak pricing and dynamic individual peak pricing) on electricity consumption for 90 different Danish household types was studied. Showing that each tariff model triggers different electricity demand profiles. The work presented in [9] investigated grid tariffs in distribution network expansion planning by assigning nodal varying transmission system usage tariffs and concluded that nodes with lower tariffs were considerably favoured by substation connections over the higher priced ones. Total investment cost savings for a 54-Node distribution system ranged from 2% to 6% with a spread in nodal tariffs from 44-94 ¢/kW. In [10] three different transmission service costs were analysed from the perspective of renewable power plant investors in generation and transmission expansion planning. The investigated scenarios concluded that, depending on the transmission service cost, there can be a deviation of one to two line investments.

While these papers have examined the effect of grid tariffs, they do not fully capture how grid tariffs and consequently altering demand profiles, affect optimal expansion planning. Furthermore, a range of different grid tariffs has not been thoroughly explored. To address this issue, a sensitivity analysis is required, where the TEP is optimised for various ratios of generation costs to grid tariffs. This approach enables a systematic evaluation of potential outcomes under different economic conditions, thereby ensuring the transmission network is prepared to accommodate a range of future scenarios.

We propose an approach to cover the grid tariff charge in the TEP optimisation formulation by assigning the line power flow a certain cost and including it in the objective function. This term simulates a variation of a grid tariff structure. Since the magnitude of grid tariff charges can affect the optimal expansion plan, expansion plans for multiple ratios of generation costs to grid tariff costs are computed. This assists in identifying the sensitivity of expansion planning to the ratio of generation and grid tariff costs and determining the fluctuation range of numerical ratios.

The rest of this paper is organised as follows. Section II describes the general TEP formulation and illustrates the proposed extension. Section III presents the results of the sensitivity analysis for two test systems, i.e., Garver's 6-Bus and the IEEE 24-Bus networks. Finally, Section IV concludes the findings and outlines future work on this research topic.

II. TEP Problem Formulation

This section introduces the mathematical formulation for the optimisation of TEP. First, a TEP formulation is presented in Section II-A which represents a widely used approach in the literature. In Section II-B, the formulation is expanded according to the proposals made at the end of Section I. In general, TEP is formulated as a mixed-integer problem. Whereas the dispatched power is modelled as a continuous variable, investment decisions present discrete decisions as they can only be implemented to their full extent and not partially. Therefore, these decisions are modelled as binary variables, consequently increasing the computational complexity of it. For an explanation of the terms in the following section, please refer to the nomenclature on page 1.

A. General Problem Formulation

The basis of TEP is the incentive of investing the least amount of capital for the greatest possible benefit. The objective function of the mathematical problem consists of the capital expenditures (CAPEX), these include, e.g., new lines, retrofit of existing ones, substation or other hardware components, and the operational expenditure (OPEX) accumulated over the planning period, such as electricity generation costs, grid tariffs and penalty costs (redispatch/load curtailment). The motivation for including the OPEX is that it is in the general interest of an expansion planner to simulate realistic power flows within the network that occur in a market-driven environment, to assess the impact of an investment.

The CAPEX (shown in (1a), within the scope of this paper we limit the expansion planning to line investments) consists of the binary investment decisions (x_l^{line}) that determine whether an investment is undertaken or not and its corresponding cost (c_l^{line}). The OPEX given in (1b) includes two terms. First, the power dispatch cost ($c_g^{gen} p_{t,g}$, $p_{t,g}$ being the power and c_g^{gen} its corresponding cost) and secondly a penalty term ($c_n^r r_{n,t}$, $r_{n,t}$ the curtailed load or redispatched power and c_n^r the corresponding cost). The second term represents the instance in which the load would need to be curtailed or more costly power redispatched due to network constraints.

Formulation 1: General TEP

$$\min_{p,\, r,\, x^{line}} \text{CAPEX} + \frac{1}{T}\sum_{t\in T} \text{OPEX}_t \tag{1}$$

$$\text{CAPEX} = \sum_{l\in L'} c_l^{line} x_l^{line} \tag{1a}$$

$$\text{OPEX}_t = \sum_{g\in G} c_g^{gen} p_{t,g} + \sum_{n\in N} c_n^r r_{n,t} \tag{1b}$$

Following the objective function, the constraints used in the optimisation model are those of a DC power flow. The power flow on candidate lines is modelled via a disjunctive method [11]. The constraints for the expansion problem include the nodal balance (2a),

$$\begin{aligned}\sum_{g\in G} a_{g,n} p_{g,t} - \sum_{l\in L} A_{l,n} f_{l,t} - \sum_{l\in L'} A'_{l,n} f'_{l,t} + r_{n,t} \\ = \sum_{d\in D} b_{d,n} d_{d,t}\end{aligned} \tag{2a}$$

the linearised DC power flow equation for existing (2b) and candidate lines (2c),

$$f_{l,t} - \sum_{n\in N}\sum_{l^*\in L} D_{l,l^*} A_{l^*,n}\theta_n = 0 \tag{2b}$$

$$\begin{aligned}-M_l(1-x_l^{line}) \le f'_{l,t} - \sum_{n\in N}\sum_{l^*\in L'} D'_{l,l^*} A'_{l^*,n}\theta_n \\ \le M_l(1-x_l^{line})\end{aligned} \tag{2c}$$

as well as their respective allowed limits (2d) and (2e).

$$-f_l^{max} \le f_{l,t} \le f_{l,t}^{max} \tag{2d}$$

$$-f_l'^{max} x_l^{line} \le f'_{l,t} \le f_{l,t}'^{max} x_l^{line} \tag{2e}$$

Additionally, the constraints include the boundaries for line curtailment (2f), power generation (2g), and angle (2h).

$$0 \le r_{n,t} \le \sum_{d\in D} b_{d,n} d_{d,t} \tag{2f}$$

$$p_g^{min} \le p_{g,t} \le p_g^{max} \tag{2g}$$

$$-\theta_n^{max} \le \theta_{n,t} \le \theta_n^{max} \tag{2h}$$

B. Proposed Problem Formulation

This paper proposes an approach, where the grid tariff is set to be proportional to the sum of the absolute values of the power flow on all lines. In the proposed formulation, (1) has to be modified by additional variables in the objective function, as the OPEX term gets expanded by the grid tariff term and now has the structure shown in (3b).

Formulation 2: Proposed TEP with grid tariff costs

$$\min_{p,\, r,\, x^{line}, f, f'} \text{CAPEX} + \frac{1}{T}\sum_{t\in T} \text{OPEX}_t \tag{3}$$

$$\text{CAPEX} = \sum_{l\in L'} c_l^{line} x_l^{line} \tag{3a}$$

$$\begin{aligned}\text{OPEX}_t = \sum_{g\in G} c_g^{gen} p_{t,g} + \sum_{n\in N} c_n^r r_{n,t} \\ + \sum_{l\in L} c_l^{GT} |f_{l,t}| + \sum_{l\in L'} c_l^{GT} |f'_{l,t}|\end{aligned} \tag{3b}$$

In order to linearise the absolute value of the power flow on existing and candidate lines, we split it into its positive and negative parts. Through this reformulation, the optimiser is incentivised to keep the positive and negative parts to a minimum, while still satisfying the constraint of matching the value of the power flow (4c) and (4d).

$$|f_{l,t}| = f_{l,t}^+ + f_{l,t}^- \tag{4a}$$

$$|f'_{l,t}| = f_{l,t}'^+ + f_{l,t}'^- \tag{4b}$$

$$f_{l,t} = f_{l,t}^+ - f_{l,t}^- \tag{4c}$$

$$f'_{l,t} = f_{l,t}'^+ - f_{l,t}'^- \tag{4d}$$

III. Grid Tariff Sensitivity Analysis

One aspect of interest in this study is to determine the impact of the grid tariff term in (3b) on the resulting expansion plan. The ratio between power dispatch costs and grid tariffs is expected to have a large impact on the results, as one dominating the other will incentivise different power routing and hence the line expansion. The formulation is applied to a modified version of Garver's 6-bus test system and the IEEE 24-bus system. Within the scope of this analysis, we refrain from analysing multiple time points, but instead refer to a single time point for the power flow evaluation for each network, resulting in $t = 1$. Due to that, the t-index was omitted in the following equations.

A. Modified 6-Bus System

Within this subsection, a modified version of Garver's 6-Bus test system is analysed under this new formulation. The network can be seen in Fig. 1 where the existing lines are the solid black lines, candidate lines as dashed lines, buses of demand are denoted as blue, high-cost generation as red and low-cost generation as green. The set of expansion options is taken from [12] and listed in Table I.

The test system is modified in the sense that the generation at bus 6 is set to be the cheapest at a price of 0 \$/MW. The other two generation units located at bus 1 and bus 3 produce at a cost of 10 \$/MW. The redispatch costs were set to be of the order of 10,000 \$/MW. This drastically disincentivises redispatch, but still allows for it to occur. The parameters for

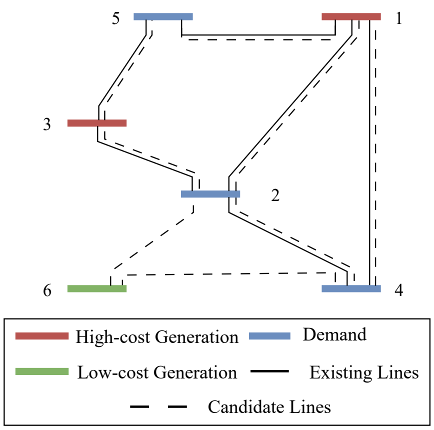

Fig. 1. Garver 6-Bus test system. The buses with net demand are coloured blue, the ones with high-cost generation in red and low-cost generation in green. Lines are coloured black, with the existing lines solid and candidate lines dashed.

the test are given in Table II. See [12] for further information on the transmission line data (cost, maximum power transfer, and reactance).

A sensitivity analysis is carried out to assess the impact of the proposed TEP formulation. For this, the ratio of power dispatch costs and grid tariffs is varied at fixed line expansion and redispatch costs. The individual generation costs are varied from 0 \$/MW to their respective maximum value (given in column c_g^{gen} [\$/MW] of Table II), whilst the grid tariff is varied from 0 \$/MW to the maximum average generation cost which is defined as the maximal value that the average MW unit costs ($\overline{c_g^{gen}}$). This amounts to 4.6 \$/MW (see (5)) in this test.

$$\overline{c_g^{gen}} = \frac{\sum\limits_{g \in G} c_g^{gen} p_g^{max}}{\sum\limits_{g \in G} p_g^{max}} \approx 4.6\,\$/\mathrm{MW} \tag{5}$$

For proper resolution, the given range of possible generation and grid tariff cost is divided into 21 evenly spaced increments and thus resulting in 441 possible combinations. For Garver's 6-Bus system, the generated results are listed in Table III and depicted as a heatmap in Fig. 2. It can be seen that the optimiser generally pursues an expansion plan that connects bus 6 to the network, due to the low generation costs and high redispatch costs.

The graphic seems to be roughly split along its diagonal, into a left and a right triangle. The two dark blue solutions, i.e. A.1 and B.1, are very similar and also result in identical

TABLE I
EXPANSION OPTIONS FOR GARVER'S 6-BUS SYSTEM

From – To	1–2	1–4	1–5	2–3	2–4	3–5	2–6	4–6
Number of possible addition	2	2	2	2	2	2	4	2

TABLE II
DEMAND AND GENERATION ALLOCATION FOR GARVER'S 6-BUS SYSTEM

Bus	Demand [MW]	Max. Generation [MW]	c_g^{gen} [\$/MW]
1	80	150	10
2	240		
3	40	360	10
4	160		
5	240		
6		600	0
Total:	760 MW	1110 MW	

objective function values for the various generation and grid tariff ratios in the left triangle.

As can also be seen from the plot, if the grid tariff is set low and the dominant cost is electricity generation, the consumers will buy as much cheap electricity as possible and hence connecting to bus 6 as much as possible does present to be the optimal investment (which can be seen by the expansion plans both containing four connections between bus 2-6 and two connections between 4-6). The only deviation between these plans is the line expansion of 1-5 or 3-5, which, as previously stated, results from both plans giving equal objective function values.

As the ratio shifts more towards equality, the optimiser starts to dispatch more costly power from bus 3 instead of cthe heap one from bus 6, which decreases the need for additional line expansion. This is seen in the light blue, i.e., C.1 expansion plan, which is similar to the dark-blue plans, but has one less line connecting buses 2-6.

This effect amplifies as the grid tariffs become the dominant factor. The white plan D.1 installs another connection between buses 3-5 to dispatch even more power from the generator at bus 3.

In the case that generation is very cheap compared to the grid tariff (red area in Fig. 2, the optimal expansion plan for this scenario (E.1 and F.1) is just focusing on having centralised generation (generation as close to hubs of demand, opposite to decentralised generation which is generation distant from the demand).

As expected, the increasing grid tariff does incentivise centralised generation. In addition, in Fig. 2 it can be seen that the optimal expansion plan does not change too much for

TABLE III
COLORBAR LEGEND OF EXPANSION PLANS FOR MODIFIED GARVER'S 6-BUS SYSTEM

Plan	New lines 1–5	2–3	2–6	3–5	4–6
A.1	1		4		2
B.1			4	1	2
C.1			3	1	2
D.1			3	2	2
E.1		1	1	1	2
F.1			2	1	2

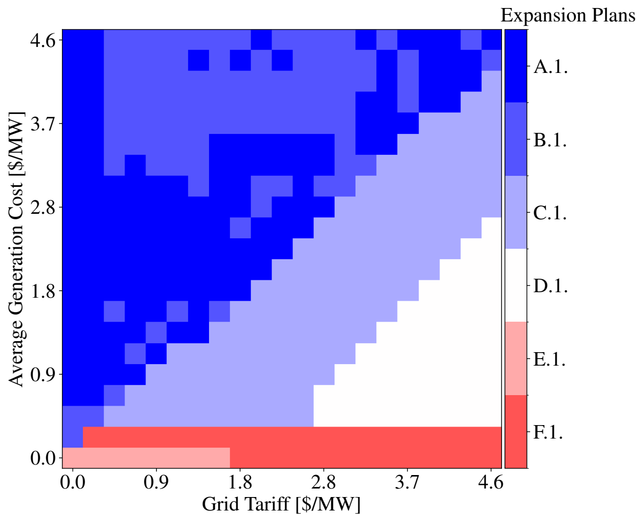

Fig. 2. Heatmap of the sensitivity analysis for Garver's 6-Bus system.

different ratios of c_g^{gen} and c_l^{GT}. This is due to the simple structure of the network and limited expansion options.

B. IEEE 24-Bus System

The same analysis is carried out for a modified IEEE 24-Bus test system. The relevant network data can be found in [13]. Similar to [11], the maximum capacity of existing and candidate lines is reduced to one third of the original capacity given in [13]. The set of candidate lines consists of the existing connections These can be retrofitted to have two more lines per corridor.

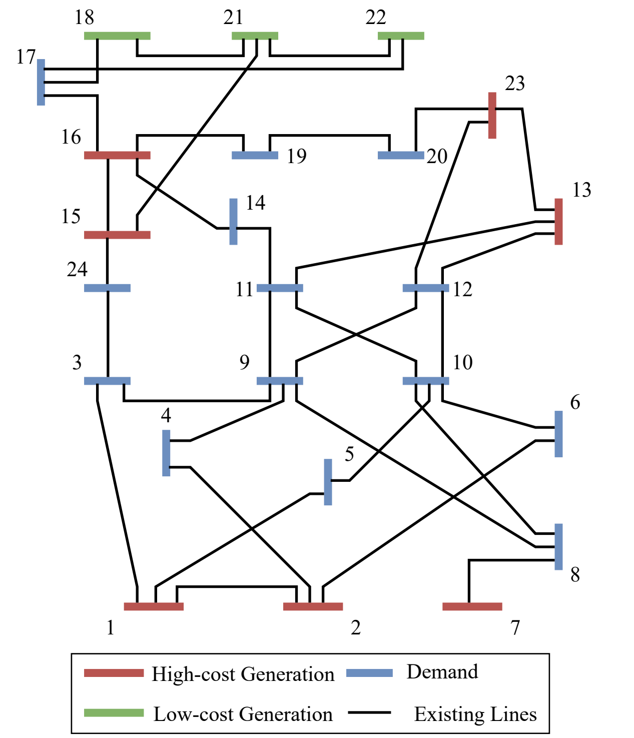

Fig. 3. Diagram of IEEE 24-Bus system. The buses with net demand are coloured blue, the ones with high-cost generation in red and low-cost generation in green. Black solid lines indicate the existing lines.

Similar to the Garver's 6-Bus test case before, an area of low generation cost is artificially integrated. This concerns bus 22 which has a generation of 300 MW and a relative cost of 0 $/MW. Other than that, the cheapest generation according to [13] is found in buses 18 and 21. This concludes that the cheapest generation is placed at the top of Fig. 3.

The resulting plans are listed in Table IV and can generally be categorised into three subgroups (blue, red and light-coloured areas in Fig. 4). The blue area contains the plans with generation costs being the dominant term, whereas red is the region of high grid tariff compared to generation costs, and the light-coloured space contains solutions to balanced ratios.

In the blue section, the expansion plans favour connections that enable the full utilisation of cheap generation. This is evident by the extensive connection of 3 to 24, twice 15 to 21, 16 to 17, and 15 to 24, allowing for cheap electricity to make its way towards buses of high demand such as busses 1, 3, 9, 14 and 15 (these amount to one third of the whole network demand).

A balanced ratio between generation cost and grid tariff is given in expansion plan I.2. Here, the line retrofitting occurs further away from cheap generation as the grid tariff weighs in on the profitability of transferring cheap electricity over greater distances. The line retrofit of 15 to 21 is due to bus 15's high demand of 317 MW.

Lastly, the extremum of grid tariffs being significantly more expensive than generation costs. The expansion plan O.2 does not seem to deviate too much from plan I.2. This indicates that a further increase in the network tariff costs beyond the area after the parity between the grid tariff and the average generation price will not lead to a significant deviation from the expansion plan as the optimiser already favours centralised electricity generation over the costly transport of cheaper energy.

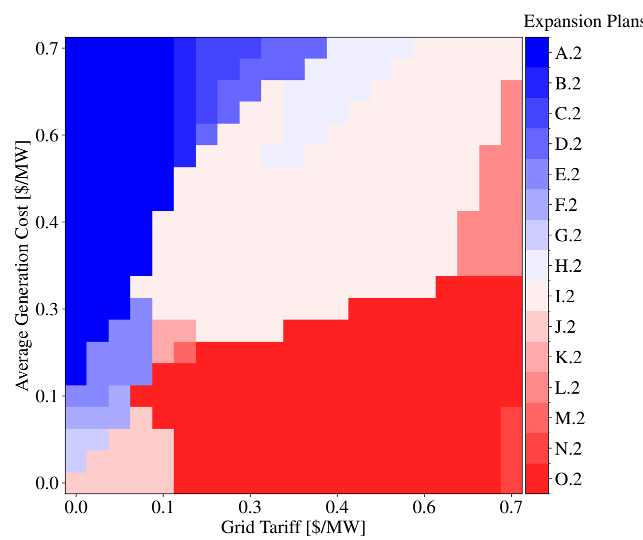

Fig. 4. Heatmap of the sensitivity analysis for IEEE 24-Bus system.

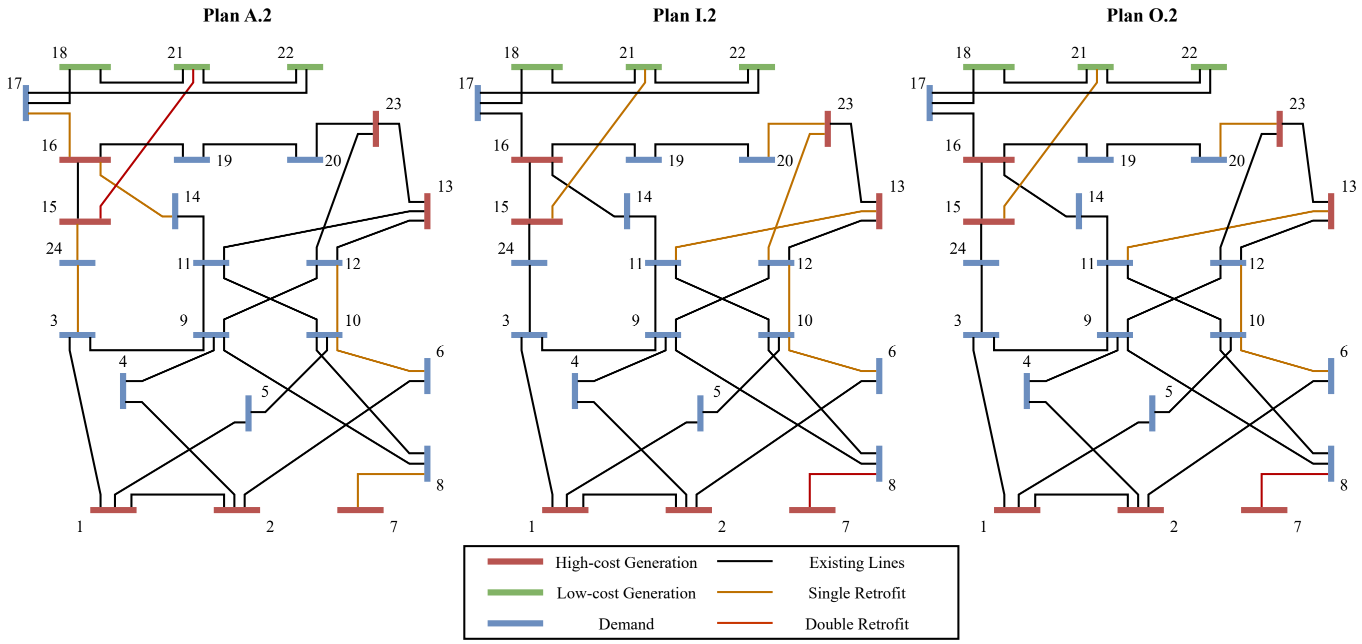

Fig. 5. Influence of tariff vs. generation cost ratio on various expansion plans. The buses with net demand are coloured blue, the ones with high-cost generation in red and low-cost generation in green. Existing lines are coloured black, single retrofits as orange and double retrofits as red.

TABLE IV
EXPANSION PLANS FOR THE MODIFIED IEEE 24-BUS SYSTEM.

Plan	Number of added lines											
	3–24	6–10	7–8	10–11	10–12	11–13	12–23	14–16	15–21	15–24	16–17	20–23
A.2	1	1	1		1			1	2	1	1	
B.2	1	1	2		1			1	2	1	1	
C.2	1	1	2		1	1		1	2	1	1	
D.2	1	1	2		1	1		1	2			1
E.2		1	2		1	1		1			1	1
F.2		1	2		1	1					1	1
G.2		1	1	1		1		1			1	1
H.2		1	2		1	1	1	1	1			1
I.2		1	2		1	1	1		1			1
J.2		1	2		1	1						1
K.2		1	2		1	1	1					1
L.2		1	2		1	1	1		2			1
M.2		1	2		1	1		1	1			1
N.2		1	2		1	1			2			1
O.2		1	2		1	1			1			1

IV. CONCLUSION

The contribution of this paper is to present a method for incorporating a grid tariff structure into transmission expansion planning. Additionally, it prepares the foundation for including different grid tariff schemes in the TEP formulation.

The sensitivity analysis was able to conclude that when the cost of transferring power rises to the average generation cost, the electricity consumer will refrain from consuming cheap electricity that has to be transmitted over extended distances and rather will dispatch closer but also more expensive generation. The optimal expansion plan for this instance dictates retrofitting lines according to these dispatch patterns. It could be shown that the plan of connecting closer but more expensive generation does not deviate significantly once this threshold is surpassed. Hence, running simulations for grid tariff costs higher than the average generation cost will not result in new findings for the expansion planner.

Another point of view is to interpret the grid tariff term as a regularisation term that reduces the amount of power flowing in the network. Since renewables offer a cheap generation source, their power is regularly dispatched to the full extent. Therefore, a version of an optimal expansion plan seeks to retrofit the lines offering further power flow from these sources. However, since renewable generation can be located afar from where it is being consumed, it has to be transmitted over large distances and is thus more prone to line outages than local generation. In the instance that the grid tariff costs in (3b) are raised, the optimiser penalises this long-range power flow and encourages to choose an expansion plan that links more local but more expensive generation to demand. In general, if there is a high amount of power flowing in the network, it means that generation does not occur on buses where it is being consumed and could therefore be prone to outages in the ieventof line failure. In the extreme case of the flow term dominating the objective function, it is obvious that the optimiser will only allow for central energy consumption, whereas the other extremum (the line power flow not being a factor of influence) means acquiring the cheapest power generation under given network constraints.

To conclude, the formulation could allow for creating a more line-outage-resilient expansion plan without the need to increase computational complexity by running more scenarios or reformulating towards a stochastic approach. This however, is still a matter of ongoing investigation.

Further work will focus on improving the grid tariff formulation aso s to be able to integrate different grid tariff structures into the TEP formulation. This will enable a market-driven co-planning strategy of battery energy storage and transmission lines that can showcase the positive benefits batteries offer in decreasing the peak power demand of market participants and hence lowering their grid tariff expenses. Another advantage will be the more accurate simulation of consumer behaviour, as grid tariffs will account for a larger share of consumers' electricity bills in the near future. The reason for this is that most transmission system operators will increase their costs in order to be able to finance the necessary rising expansion costs and also to disincentivise high peak consumption while grid expansion is not yet sufficiently advanced.

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