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Photovoltaic hosting capacity improvement based on the economic comparison between curtailment and network upgrade

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Abstract
The upcoming network investment decisions and regulatory framework adopted by distribution system operators (DSOs) are most likely to be impacted by the integration of fluctuating distributed generation. The economical hosting capacity (HC) improvement method is investigated in this paper as a trade-off between curtailment and upgrade using a Monte Carlo simulation procedure. The associated costs of both methods are vital indicators for network operators that are trying to maximize the HC and minimize cost. In addition, the breakeven point where curtailment and upgrade costs intersect is the decisive point at which network upgrade becomes sensible as marginal curtailment cost exceeds upgrade cost. A shift in global climate conditions can impact the photovoltaic (PV) levels that motivate network operators to investigate PV penetration, especially in colder climate regions. Thus, the primary objective of this paper is to investigate the shift of the breakeven point to guide DSOs to either adopt PV curtailment as a temporary measure or grid upgrade as a risk aversion strategy considering Finnish climate and load patterns. The real-time load and PV generation data are utilized for the simulations to consider the dynamic performance indication of three Finnish distribution networks. Curtailment remains a low-cost option to obtain a percentage HC rise of 13%, 7%, and 8% for rural, suburban, and urban regions, respectively, beyond which curtailment compensation cost surpasses upgrade cost. In essence, PV curtailment serves as an immediate and least-cost solution to relieve network violations and defer network investment until the HC level (118%, 106%, 97%) making the upgrade a practical option afterwards.

1 | INTRODUCTION

The clean energy perspective of future power systems encouraged large investments in distributed generation (DG) units and an increasing amount of funds are being allocated to utilize green energy as much as possible. The hosting capacity (HC) does not limit photovoltaic (PV) integration but points towards a level to deploy mitigation means to address network issues. The network upgrade is the conventional approach for hosting rising PVs, and continuous expansion planning is inevitable to satisfy operational standards. Thus, the appropriateness of network upgrade, volt-var control, and energy management system was compared on a cost basis for improving HC and specific network conditions were concluded to be the most impactful in the prioritization of any technique [1]. This study strengthened the idea of upgrade cost dependence on network conditions, where load values, positioning, and PV location significantly impacted upgrade cost. Therefore, comparative analysis of various cost drivers of networks can provide useful planning guidelines to distribution system operators (DSOs) working towards network stability.

Network performance can be investigated by various impact factors, mainly voltage rise and overloading issues that can be improved to increase the hosting capacity [2–5]. Thus, voltage management as a key operational challenge was discussed in [6, 7] and the authors presented various techniques to improve HC. The voltage rise problem in a Swedish 28-customer suburban network was technically addressed by reinforcing the feeder and service cable in [6] using stochastic planning without considering the cost implications of network upgrade. Moreover,
[8, 9] proposed regulation of PV inverters for managing the voltage rise issues due to reverse power flow. In this context, real-time PV curtailment and reactive power variation approaches were proposed in [8] to regulate the voltage rise issues through local control of PV inverters. Similarly, overvoltage was prevented by inverter shutdown in an Australian distribution network to improve PV HC [9].

The comparison/combination of upgrade with other mitigation means was performed in different studies to improve HC by either deferring the upgrade or finding the optimal combination of upgrade with other means [10]. Similarly, various studies in the reviewed literature assessed the potential of battery storage for HC improvement [11–13]. Moreover, demand response is an increasingly used method to establish supply-demand balance in energy networks and a joint operation of wind curtailment, demand response, and network reinforcement was analysed in [14] for improving HC. Nevertheless, the economic evaluation of HC mitigation means becomes indispensable for DSOs to cope with the technical and economic challenges.

The curtailment, as a control mechanism, must be compensated by DSO to cover the loss of opportunity cost of the PV owner. Therefore, optimal curtailment analysis can guide and assist the DSO responsible for compensating curtailed PV producers. Curtailment benefits were discussed from DSO's perspective to remove network violations in [15–18]. Accordingly, the findings of [17] revealed that every kWh decrease in energy curtailment is beneficial, considering savings obtained through reduced compensation. Moreover, the effectiveness of curtailment was also addressed in [18] to increase the HC using a statistical planning method supporting the fact that a moderate amount of annual curtailment was an attractive substitute for expansion planning. In addition, curtailment benefits were investigated in [16] and the connection capacity of networks was found to be doubled by dynamically curtailing 5% of yearly feed-in power. It would be equally beneficial to study curtailment impacts from a consumer perspective for modelling appropriate compensation rules [19]. In the context of utilizing network resources, energy storage systems can be deployed to reduce energy curtailment and to raise the profit margins of various stakeholders such as DSOs and PV owners [20–22]. Consequently, the PV curtailment rate was reduced by 14.2% and 50% using optimal storage systems in [21] and [22], respectively. The former study observed an additional advantage of stakeholder profit reaching 154 million dollars and later was accompanied by a reduction of financial losses as a by-product.

Distribution system operators can postpone network upgrades by, for example, optimally curtailing the energy during a few worst-case hours causing network violations. Thus, the underlying economic aspects of different approaches were analysed in the literature and the authors of [23] found the optimal combination of curtailment and upgrade. Moreover, curtailment was seen as not only the loss of clean energy but as an inevitable revenue loss for the PV owners [24]. The authors of the aforementioned study compared voluntary and involuntary curtailment and highlighted that network operators should consider reinforcement to accommodate PVs to avoid increasing curtailment compensation costs. The basic method of DG curtailment does not consider any network conditions and curtails power even without encountering any network problems [25]. Consequently, the social efforts to enhance clean energy integration become passive, thus requiring proper planning procedures and tariff designs for a DSO's cost evaluation who is responsible for paying compensation costs in involuntary curtailment.

The interdependence of curtailment percentage, compensation mechanism, DG investments, and network planning was discussed in various studies [26–28]. These studies provided insight into mitigating harmful PV impacts while analysing network cost structure for future regulatory decisions. Thus, the relevance between network planning and economic regulations was investigated in [26] where the DG units were owned by customers and not by the DSOs. Similarly, a fair curtailment allocation scheme was proposed in [27] to find the optimal curtailment regulation by using a game-theoretic approach. Finally, the utilization of customer resources is of paramount importance in network analysis on an economic basis. In this context, the authors of [28] evaluated curtailment influence on customers and these findings can be proven as a useful guideline for DSOs to set compensation rules to fully deploy customer-side resources.

Renewable energy potential is continuously on a rising trend in Finland to promote self-sufficiency and reduce greenhouse emissions with a major share of bioenergy. Moreover, the future regulations regarding energy usage of buildings in Finland are proving to be a significant driver to increase utilisation of solar power. The cost analysis to aid network operators aspiring to meet Finland’s renewable energy targets and improve networks’ hosting capacity is valuable considering the growth potential of PV power. Moreover, global warming is creating distinct impacts based on the geographical location of a network. The temperature rise, cloud cover, and precipitation patterns are a few among many climate indicators that impact the solar irradiance levels reaching the earth. The existing literature discussed different approaches to increasing the PV hosting capacity of networks based on different customer densities and geographical locations. Thus, it would be vital to investigate Finnish distribution networks, geographically located in a colder climate, with distinct heating load patterns regarding rising PV penetration. The use of Finnish distribution networks regarding the assessment of PV hosting capacity is motivated by several factors. To start with, the geographical location of Finland represents cold climate regions where the heating loads constitute the major portion of electricity consumption. This provides a huge potential to investigate the challenges and opportunities specific to colder climate such as heating loads, reduced solar irradiation, and cloud/snow cover on the PV panels. This study will provide the unique network insights and technical challenges faced by distribution system operators in similar climates worldwide. Secondly, the data availability proved to be another motivation to conduct a DSO-oriented hosting capacity assessment.

A comparison of PV curtailment and upgrade to find the least cost option to remove network violations and integrate higher PVs is investigated in this work. The cost analysis for system operators between curtailment and upgrade is performed
based on net present worth, considering upfront capital expenditure and network losses discounted to the present. The main contributions of this paper are listed as follows.

- Investigating the curtailment compensation and network reinforcement costs from the DSO perspective to remove network violations by minimal curtailment or upgrade.
- Analysing the trade-off between curtailment and upgrade for HC improvement.
- Finding the breakeven point at which network upgrade becomes an economically feasible option to increase the hosting capacity.
- This paper is an attempt to fill the research gap of hosting capacity studies in colder climates and contributes towards the scientific understanding of PV integration in such regions.

The remainder of the paper is structured as follows. Section 2 describes input data followed by Section 3 presenting a cost assessment framework. Section 4 presents the simulation results. Section 5 provides the discussion, and the concluding remarks are presented in Section 6.

2 | LV NETWORK MODELLING

Low-voltage distribution networks are particularly prone to equipment overloading and voltage rise issues due to the large share of rooftop photovoltaics. The analysis of the benefits and cost comparison of curtailment and upgrade is investigated using Finnish low voltage networks modelled in [29]. The network topologies are based on three Finnish regions in rural, suburban, and urban areas with different customer types and distribution among network nodes. Moreover, the term PV hosting capacity is defined in this study with respect to the nameplate rating of the distribution transformer.

2.1 | Yearly load and PV profiles

The initial network investment decisions are based on the PV and load profiles to select network components. A few load and PV values utilized for investment decisions can be inadequate when the cost comparison of upgrade and curtailment depends on annual losses and annual energy to be curtailed, respectively. This research study is based on DSO’s perspective aiming at maximizing PV integration in the networks by making strategic decisions. Thus, a simulation horizon spanning over a period of 1 year with time series data of loading profiles and PV generation makes this research question a planning problem.

The least-cost network planning is based on the peak feeder load for the selection of network components to handle the network loads without any contingency [30]. Thus, annual load curves scaled according to the probability of load types in each region are utilized. The analysis in this paper follows a probabilistic approach to randomly sample the load types in each region using the yearly load measurement data with 1-h resolution. The load sampling is carried out to find the peak network load that is subsequently used in planning the initial least-cost network with the network components dimensioned as per voltage drop and ampacity requirements.

Later, PVs are added among network nodes and load profiles are sampled to find the extreme combinations of highest PV generation and minimum network load to find the worst impact of distributed PV generation in the network. Heating is a major part of electricity consumption in cold climates. The investigated networks in this study are based on the real Finnish DSO surveys and real load consumption data of Finland. The load profiles are dependent on the heating methods that vary among different regions and customer types. This work is based on the residential customers equipped with rooftop PVs, and load profiles are representative of three Finnish regions. This load profiling is based on hourly kWh meter readings that clustered different heating methods based on their probability distribution in the rural, suburban, and urban regions as given in Table 1 [31]. This table represents that the heating load of each region is divided into three heating modes as storage heating, district heating, and direct electric heating. The statistical sampling of the load data based on these heating profiles accounts for these probabilities. Thus, the statistical sampling method used in this study takes into account the contribution of all load types by using 'randsample' function of MATLAB based on the associated weights of load types.

The time-series load profiles are based on heating mode proportions of three heating types: storage, direct-electric, and district heating. Moreover, the PV generation profiles utilized in this work are based on time-series PV data in the Helsinki region, considering the hypothetical maximum PV peaks for 1 year with an hourly resolution [32]. The net power at node $j$ is defined considering the PV generation as negative load as follows.

$$P_{j}^{net}(t) = P_{j}^{l}(t) - P_{j}^{pv}(t)$$

$$Q_{j}^{net}(t) = Q_{j}^{l}(t) - Q_{j}^{pv}(t)$$

The terms $P_{j}^{l}(t)$ and $Q_{j}^{l}(t)$ represent load active and reactive powers at time $t$ and node $j$. Moreover, $P_{j}^{pv}(t)$ and $Q_{j}^{pv}(t)$ are the active and reactive powers associated with PV generation modelled as negative load.

2.2 | Base case networks

The guidelines of a greenfield distribution network project are based on satisfying certain planning principles. Thus, the

<table>
<thead>
<tr>
<th>Region</th>
<th>Storage heating (%)</th>
<th>District heating (%)</th>
<th>Direct electric heating (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rural</td>
<td>5.9</td>
<td>52.9</td>
<td>41.2</td>
</tr>
<tr>
<td>Suburban</td>
<td>7.6</td>
<td>52.5</td>
<td>39.9</td>
</tr>
<tr>
<td>Urban</td>
<td>0.5</td>
<td>95.3</td>
<td>4.2</td>
</tr>
</tbody>
</table>
designed network should be able to satisfy the requirements of desired network load, voltage drops limits, ampacity limits, and low cost and avoid the prolonged overloading of the transformer. This paper follows the pattern of a greenfield project by planning and rating network components in the initial network planning phase before integrating any PVs in the network [33]. The initial network formation based on a least-cost network satisfying the technical constraints of voltage drop and ampacity violations might cause the networks to have different cable sizes for cable sections between nodes. Accordingly, this work follows the traditional conductor tapering concept using thinner lines as one moves away from the substations. The initial transformer selection is also based on peak network load with a 15% headroom even after the load growth period of 20 years to cater to future demand growth. Thus, transformers are initially loaded at around 50% of the nominal rating in the first year and 85% loading at the end of the load growth period. The main reason for installing a larger transformer with sufficient headroom at the planning stage is to avoid the substantial replacement cost of transformers compared to cables [34]. Table 2 describes the distinct features of the base case networks. In addition, the network loading contributions of storage heating, district heating, and direct-electric heating are based on [29].

Multiple factors monitor the network upgrade costs, such as different network regions comprising varying customer densities, different feeder lengths, and the type of HC constraints prevalent in the particular area. Figure 1 presents the single-line diagram of three networks used in this study.

The cost analysis of the base case networks is performed by the net present value (NPV) of investment and loss costs of the transformers and cables. The network cost is based on the capital expenditure and the lifelong operational costs during the planning horizon time. However, only the cost of losses is considered the operational cost and the maintenance and installation costs of all lines are assumed to be constant throughout the operational horizon.

3.1 | Methodology

The Monte Carlo simulation approach is used to calculate the base HC (HC without improvement) and HC improvement by sampling the load and PVs among network nodes. Different research studies focusing on the cost calculations involved in HC quantification considered voltage drop, voltage rise, cable ampacity, and transformer overloading limits as the HC defining constraints. Thus, a balanced PV installation among customer density in rural, suburban, and urban areas is investigated in this paper, subject to voltage and thermal limits as major network constraints. The studied networks are equipped with rooftop PV panels with an integration capacity incremented in steps of 100 W to the point of PV penetration triggering network violations. The statistical sampling is performed in each of the Monte Carlo iterations at the step-wise increment of PVs to fully capture the behaviour of PV addition among network nodes. Thus, it helps to identify the potential impacts of rising PVs in terms of voltage rise and thermal limits at each PV level. Moreover, this process utilizes a 1-year time series data with an hourly resolution that is later used in the selection of worst-case hours to find the hosting capacity of the network. The hosting capacity assessment is based on worst-case hours with highest PV and lowest load for reducing the computational burden of load flow analysis. The base HC is recorded at the first network violation, and HC improvement means are prioritized based on the cost comparison perspective. The proposed methodology is presented in Figure 2.

The initial network formation, as well as the network upgrade cost, is based on investment and loss costs of grid components and calculated as the net present value of total cost [35].

\[
C_{net} = CAPEX + NPV(OPEX) \tag{3}
\]

\[
C_{CB} = \sum_{i,k} C_i L_{ij} + d_{ij} \epsilon_i \sum_{i,k} 3RL_{ij} I_{ij}^2 \tag{4}
\]

\[
C_{TF} = CAPEX_{TF} + d_{ij} \epsilon_i \left( P_e + P_{loss} \left( \frac{P_{loss}}{S} \right)^2 \right) \tag{5}
\]

The network cost \(C_{net}\) is calculated in (3) as the summation of initial capital expenditure (CAPEX) and the net present value of the operational expenses (OPEX). In this work, the operational expenses are largely considered losses due to the significant influence of loss cost on investment decisions. (4) and (5) calculate the costs of cables \(C_{CB}\) and transformer \(C_{TF}\) by adding the initial expenses as the first term and the NPV of losses as the second term.

The terms \(\epsilon_i\) and \(L_{ij}\) in (4) correspond to cable cost and line length between network nodes, respectively. The calculation parameters \(m_i, \epsilon_i, d\) represent loss utilization time, cost of energy losses, and discount factor, respectively. Discount factor is an important weighing parameter for economic comparisons to determine the present value of future income in terms of operational costs over the project horizon as defined in the Appendix. Thus, the cable cost comprises investment cost and the lifetime cost of losses discounted to the present to
investigate the economic sense of the proposed upgrade. The transformer costs are similarly comprised of the investment and loss cost calculations in terms of net present value. Moreover, PV curtailment costs incurred on DSO can be visualized by using the feed-in tariff (FIT) and the amount of annual curtailed energy.

3.2 Network reinforcement approach

The business-as-usual approach used by DSOs for addressing network stability issues was to reinforce the networks. The network upgrade strategy is determined by the violations encountered at each PV level once the network limits are exceeded for the first time. Thus, the determination of violations category, such as voltage or thermal constraints, played an important role in determining the upgrade of cables, transformers, or both. The voltage rise violations are addressed by upgrading the cable conductors to lower the impedance and the associated voltage rise (or drop) issues. The networks used in this work are based on PV installations scattered homogenously among the network nodes by equal distribution of incrementing PV power among the network nodes. Thus, it is economical to favour the traditional stiffening of the network from the substation outwards. On the other hand, the cable ampacity problem is addressed by increasing the cable size among the available options in the substation inventory. The low-cost cable reinforcement procedure for addressing the voltage violations followed the network upgrade outwards substation towards the end node. This approach of network upgrade is used here because it results in lower upgrade cost as compared to the upgrade from customer upstream as shown in Figure 3.

The main steps of upgrade are described as follows.

- The violated network nodes are identified, and their location along the network feeders is saved to perform the upgrade on a per-feeder basis.
- Find the worst location among network nodes with the highest voltage rise. The networks comprising of a single feeder (rural) experience the highest voltage rise at a single end-node location in contrast to the multiple feeder networks (suburban and urban) with various end-nodes undergoing the voltage rise issues.
- The network upgrade is performed such that the reinforcement algorithm executes only until the grid violations are removed. Thus, the voltage rise problems are addressed by upgrading the cable section starting from the transformer side of the feeder length.

Load flow analysis calculates the voltages after the cable upgrade to check if the voltage violations are removed. The same cable is reinforced until the largest available size before upgrading the next cable section downstream towards the feeder's end if the violations persist. Therefore, the network is upgraded until the grid violations are eliminated for a particular PV level before incrementing the PVs in a step counter of 100 W. The associated costs of the upgrade at
3.3 Energy curtailment

An approximation of annual PV curtailment plays an instrumental role in the investment decisions of a DSO. Thus, an estimate of annual energy curtailment is considered an important metric when comparing the investment costs of network expansion and curtailment compensation costs. PV curtailment cost increases in direct proportion to the penetration level as the percentage curtailment increments with each rising PV level. This is related to the frequency of network violations that increase as more and more PVs are added among network nodes, and hence, mandate curtailment or other mitigation means.

The network stability is analysed under the worst-case hour with maximum PV generation and minimum loading to estimate the maximum stress on the network. The violation of network constraints under this worst-case PV value triggers the need to curtail the energy to restore network stability. Thus, the simulation algorithm calculates an optimal but minimal amount of percentage curtailment to relieve network violations by executing the curtailment starting from 1% to the percentage level where the network violations are removed. The worst-case PV power analysis is adequate for evaluating the violation of network constraints by running a load flow analysis. However, the curtailment compensation cost incurred on DSO is based on the PV power of worst-case hours among 8760 annual hours that resulted in network violations. Therefore, curtailment cost is calculated by the estimation of annual energy curtailed summed over the yearly time-series PV data. The annual PV generation and curtailment are based on hourly profiles scaled according to the theoretical maximum PV generation data in the city of Helsinki, as shown in Figure 4.

It is important to find the annual PV curtailment required at each PV level where the PVs are incremented in steps of 100 W until the network upgrade becomes more sensible. Finally, annual PV energy curtailment is calculated by finding the worst-case hours in 1 year and integrating the PV powers of all the hours that are required to be curtailed. The final marginal curtailment cost is based on yearly curtailed energy compensated at a feed-in tariff of 0.05 (€/kWh) and discounted to the present to estimate the economic sensibility of PV curtailment with respect to a network upgrade.
SIMULATION RESULTS

This section presents the results of simulations performed using MATLAB script to determine the economic sensibility of network upgrade and curtailment.

4.1 Percentage PV curtailment

The analysis of the annual curtailment percentage and the associated curtailment hours for three Finnish regions reveals the incremental rise in PV curtailment once the network limits are violated, as shown in Figure 5. Thus, the dynamic curtailment required to remove violations keeps on rising with increasing penetration levels. Figure 5 represents the optimal curtailment percentage for three regions as 12%, 7%, and 8% where curtailment cost remains lower than upgrade cost. These incremental levels of PV curtailment give an indication of the upgrade to be a potential solution for removing grid violations. Therefore, curtailment percentage levels can be used as an estimate for DSOs to prepare network resources for an indispensable grid upgrade.

4.2 Marginal curtailment vs upgrade

PVs are incremented in the network after the first violation until the level when the curtailment cost exceeds the upgrade cost, making network reinforcement an economically sensible option to sustain network stability. PV curtailment remains an economic option as compared to network upgrades until a certain PV penetration level, as shown in Figure 6. The breakeven point in Figure 6 shows the transitioning level when the curtailment percentage increases to the level that the associated cost surpasses the grid upgrade cost. The upper subplots of Figure 6 show the PV hosting capacity, measured as a percentage of transformer rating, as a function of PV addition levels in steps of 100 W. At the same time, the lower plots are the comparison between upgrade and curtailment costs and show the increased PV levels (100 W) by removing network violations.
**FIGURE 5** Percentage curtailment and annual curtailed hours at PV levels requiring mitigation means (a) rural, (b) suburban, (c) urban. PV, photovoltaic.

**FIGURE 6** HC improvement and the comparison of curtailment and upgrade in terms of marginal costs (a) rural, (b) suburban, (c) urban.
The simulation results of marginal cost comparison show that a single-time upgrade can give larger headroom to incorporate PVs in contrast to curtailment where curtailment percentage augments at each PV level to remove violations. Thus, curtailment can be employed to prepare the resources to upgrade the network instead of sudden decisions on grid upgrades. It has been observed that rural region has a larger potential of using curtailment to improve HC as network upgrade cost is higher due to longer line spans, single-feeder configuration, and frequent voltage violations. This can be substantiated by the 12% curtailment percentage compared to the 7% and 8% curtailment percentages for the suburban and urban regions, as discussed in Section 4.1. In contrast, the upgrade cost in the suburban and urban regions is comparatively lower to remove network violations due to a three-feeder configuration and node distribution among three feeders. This work compared the associated costs of the upgrade and the curtailment, and the analysis is terminated when the curtailment costs exceeded the upgrade cost. Thus, the networks retained their original dimensions without upgrade as long as curtailment remained a least-cost solution. After this point, the upgrade is the most cost-effective solution as the curtailment compensation cost surpasses the upgrade cost.

The point of the economic sensibility of the network upgrade, which soon becomes a cost-effective option, for the suburban and urban regions can be attributed to the type of network violations. Voltage rise is the most commonly occurring violation in all the regions. The network upgrade in the rural network required considerable instances of cable upgrades because voltage problems particularly dominate the regions with low population density and long feeders. Moreover, rural regions are particularly challenging due to their inherent spatial expansion and long lines, especially with the PV connections at the end of long weak feeders. On the other hand, the network topology of the suburban and urban regions comprises multiple feeders with shorter line lengths as compared to rural regions. Therefore, the cable upgrade costs to mitigate the voltage rise of these regions proved as a lower threshold for curtailment. It is because of this reason that the curtailment cost for the urban and suburban regions soon exceeds the upgrade cost at the breakeven point.

### 4.3 Cumulative curtailment cost vs upgrade cost

Deferral of network upgrade investment can be considered the primary benefit of energy curtailment that might be deployed as a short-term solution to curtail the hours causing violations in the network operational conditions. However, long-term planning might prove the network upgrade as the most economically viable option over curtailment, considering the higher curtailment percentage with rising penetration levels.

A comparison of marginal and cumulative curtailment costs and the shift of the breakeven point is analysed in Figure 7. It shows that increased PV penetration levels can be achieved...
with a single-network upgrade as the initially lower marginal curtailment cost exceeds the upgrade cost eventually. It is apparent that the marginal curtailment cost is not stationary and keeps on increasing with rising PVS. Figure 7 shows that the cumulative compensation cost exceeds the upgrade cost at a PV level prior to the point at which marginal curtailment cost exceeds upgrade cost. Thus, the consideration of cumulative curtailment cost further shifts the breakeven point to the left at a decreased PV level reducing the competitiveness of curtailment.

Therefore, it is important to analyse the cumulative curtailment compensation cost incurred upon the DSOs to compare its effectiveness with the upgrade cost. This cumulative curtailment cost is the net sum of all the marginal compensation costs until the level when marginal curtailment cost exceeds upgrade cost as given in (6). $N$ represents the breakeven point where marginal curtailment cost exceeds upgrade cost.

$$\text{Cumulative Curt cost} = \sum_{n=1}^{N} \text{Marginal Curt cost}$$

4.4 | Sensitivity analysis

The cost and benefit analysis of curtailment vs upgrade is based on the financial losses associated with PV curtailment in terms of compensation cost. The regulatory framework dictating the electricity market price plays a significant role in this regard as the curtailed PV owners are compensated by DSO at the rate of the feed-in tariff. Thus, a sensitivity analysis is carried out by changing FIT to investigate the deviation of the breakeven point and optimal curtailment percentage at the breakeven point. It has been observed that the breakeven point, at which the upgrade becomes more sensible, shifts in accordance with the changes in market price. Thus, optimal curtailment percentage and hosting capacity deviate such that there is a negative linear relationship between curtailment percentage and feed-in-tariff.

Figure 8 depicts curtailment variation with compensation cost representing a strong $R^2$ value: goodness of fit measure (0.947), indicating a fitted regression line. The negative correlation is apparent in Figure 8, which shows the curtailment percentage at breakeven points for three regions with a negative slope. Reducing base case FIT from 0.05 (€/kWh) to half indicates that the upgrade can be postponed further due to a reduction in associated curtailment compensation cost. On the other hand, percentage curtailment and hence, the curtailment cost soon exceeds the upgrade cost in case the FIT is increased to double.

5 | DISCUSSION

The modern energy landscape calls for active network management strategies to satisfy the statutory limits of networks. The equilibrium between the over-investment in the network upgrade and under-investment in the renewable generation has been a topic of discussion recently to investigate the economic losses on the part of DSO. DSOs, while being obligated to guarantee the provision of voltage satisfying power quality standards, also take an interest in minimizing the present worth of grid operation. Thus, the economic considerations along with the technical viability of networks can be a challenging task for network operators. In this situation, the operational challenges faced by system operators are two-sided: to maximize the utilization of clean and abundant energy sources and to maintain network cost structure to be minimum. Accordingly, DSOs can either opt to temporarily curtail PVS or reinforce distribution networks as a final resort to maintain the stability of the network. However, substantial network upgrade costs for accommodating future load growth and increased PV penetration might prove as a deterrent for network operators that are trying to find cost-optimal solutions. On the other hand, HC as installed capacity can be improved with curtailment as an immediate solution but provides no financial potential at a later stage of PV penetration.

This discussion implies that the network cost allocation and estimation should not be merely based on the installation cost of DG units. Instead, a substantial amount must be reserved for handling the network issues arising from intermittent generation. A share of such costs is associated with the risk of excessive generation surpassing the demand level which should be curtailed to maintain stability. In addition, the value of curtailed PV generation can be visualized by ‘who pays’ and ‘how much’ and consequently depends on ‘who initiates’ the curtailment. The network prosumers are not required to pay any penalty to the energy companies even if network limits are violated but PV installations comply with connection/fuse size. In this regard, system operators are required to step in to mitigate network
violations and perform economic measures. Thus, curtailment not only proves as an economic disadvantage in the form of lost ‘green energy’ but the added financial penalty on DSOs as involuntary curtailment compensation cost.

The involuntary curtailment due to network constraints is analysed in this work by a comparison of curtailment compensation cost and upgrade cost. A comparative analysis is conducted to find the economical option for DSOs that are deemed responsible for taking corrective actions regarding network expansion planning. Thus, optimal curtailment proved as the least cost solution for three Finnish regions to remove network violations until a certain PV penetration. After this point, the curtailment percentage and associated compensation costs rise to the extent that an upgrade proves to be a more cost-effective measure.

However, there is a debate on the loss of green energy due to PV curtailment. As a solution, energy loss can be reduced by intermediate storing the energy and utilizing it in demand response programs for maximizing the PV self-consumption. Regardless, the underlying costs of battery purchase and demand response execution should be scrutinized to provide a comprehensive method for increasing hosting capacity while minimizing DSOs costs. Battery sizing and demand response schemes along with grid upgrade are a few among many alternatives to explore to minimize the loss of clean energy that would be investigated as a future work using optimization-based studies.

6  |  CONCLUSIONS

The research work performed in this article is focused on increasing the HC of distribution networks while finding the cost-effective option among upgrades or curtailment from a DSO's point of view. Deferral of network upgrade investment is found as the primary benefit of energy curtailment that might be deployed as a short-term solution to curtail the hours causing violations in the network operational conditions. Moreover, curtailting PV power, on instance of network violations, is proved to have greater potential for rural region due to higher upgrade cost associated with longer line spans. On the other hand, the curtailment potential soon exhausts for suburban and urban regions due to increased density of customer PV installations. It is noted that curtailment relieves network congestion at only a particular penetration level with an associated compensation cost in contrast to the network upgrade that might give a larger headroom to increase the HC until the violations are encountered again. Moreover, cumulative compensation costs of DSOs make it a less attractive option considering not only the loss of clean energy but an incrementing cost to be paid to curtailed customers. Thus, a network upgrade can be considered a good return on investment for the DSOs with sufficient upgrade resources in terms of increasing HC instead of resorting to curtailment. On the other hand, curtailment can be proved as a waiting mechanism for the DSOs to tactfully allocate the resources to increase PV penetration in case of lower resource availability for network upgrades.

In essence, apart from highlighting the strategic investment decisions by Finnish DSOs, this research establishes a foundation for future studies in similar climates with unique generation and consumption patterns. This can ultimately lead towards the cross-border comparisons for fulfilling the future renewable energy integration targets worldwide.

NOMENCLATURE

Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPEX</td>
<td>capital expenses</td>
</tr>
<tr>
<td>DSO</td>
<td>distribution system operators</td>
</tr>
<tr>
<td>DG</td>
<td>distributed generation</td>
</tr>
<tr>
<td>HC</td>
<td>hosting capacity</td>
</tr>
<tr>
<td>NPV</td>
<td>net present value</td>
</tr>
<tr>
<td>OPEX</td>
<td>operational expenses</td>
</tr>
<tr>
<td>PV</td>
<td>photovoltaic</td>
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</table>

Symbols

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_c$</td>
<td>cable cost</td>
</tr>
<tr>
<td>$i_d$</td>
<td>cost of energy losses</td>
</tr>
<tr>
<td>$C_n$</td>
<td>cost of entire network</td>
</tr>
<tr>
<td>$C_{CB}$</td>
<td>cost of cables</td>
</tr>
<tr>
<td>$C_TF$</td>
<td>cost of transformer</td>
</tr>
<tr>
<td>$d$</td>
<td>discount factor</td>
</tr>
<tr>
<td>$i_j$</td>
<td>indices of network nodes</td>
</tr>
<tr>
<td>$I_j$</td>
<td>current flow between nodes</td>
</tr>
<tr>
<td>$k$</td>
<td>number of line sections</td>
</tr>
<tr>
<td>$L_{ij}$</td>
<td>line $i$ length</td>
</tr>
<tr>
<td>$P_n$</td>
<td>no load losses</td>
</tr>
<tr>
<td>$P_m$</td>
<td>copper losses</td>
</tr>
<tr>
<td>$R$</td>
<td>resistance</td>
</tr>
<tr>
<td>$S$</td>
<td>transformer rating</td>
</tr>
<tr>
<td>$n_i$</td>
<td>utilization time of losses</td>
</tr>
</tbody>
</table>

AUTHOR CONTRIBUTION

Samar Fatima: Conceptualization, Formal analysis, Investigation, Methodology, Software, Visualization, Writing—original draft Verner Püvi: Data curation, Formal analysis, Software, Validation, Writing—review & editing Mahdi Pourakbari-Kasmaei: Conceptualization, Formal analysis, Resources, Supervision, Writing—review & editing Matti Lehtonen: Conceptualization, Data curation, Project administration, Supervision

CONFLICT OF INTEREST STATEMENT

The authors declare no conflict of interest.

DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available from the corresponding author upon reasonable request. The data are not publicly available due to privacy.

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APPENDIX

This section provides the definition and values of economic terms for the calculation of net present value of grid components as discussed in Section 3.1.

\[ d = \alpha_1 \times \frac{\alpha_1' - 1}{\alpha_1 - 1} + \alpha_2 \times \frac{(1 + r)^{2t}}{(1 + p)^t} \times \frac{(\alpha_2^{T-t} - 1)}{\alpha_2 - 1} \]  

(A.1)

(A.1) gives the mathematical calculation of the discount factor (\(d\)) where the terms \(\alpha_1\) and \(\alpha_2\) are given as follows:

\[ \alpha_1 = \frac{(1 + r)^2}{1 + p} \]  

(A.2)

\[ \alpha_2 = \frac{1}{1 + p} \]  

(A.3)

The economic parameters for calculations are given in Table A1.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planning horizon ((T))</td>
<td>40 years</td>
</tr>
<tr>
<td>Load growth period ((t))</td>
<td>20 years</td>
</tr>
<tr>
<td>Interest rate ((\rho))</td>
<td>5%</td>
</tr>
<tr>
<td>Load growth rate ((\rho))</td>
<td>3%</td>
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<tr>
<td>Utilization time of losses ((\mu))</td>
<td>2000</td>
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<tr>
<td>Cost of energy losses ((c_\ell))</td>
<td>(5 \times 10^{-5})€/Wh</td>
</tr>
</tbody>
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