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Report

DSO and LEC Collaboration Strategies for Voltage Regulation

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SUMMARY
This report explores the long-term perspective of Local Energy Community (LEC) integration, considering future grid challenges like load increases leading to voltage problems. It examines the role of LECs in reducing peak loads and subsequent contribution to voltage regulation, especially when LECs include flexible resources. The report focuses on three key scenarios: Business as Usual, Local Coordination, and Efficient Market, each illustrating different interactions and integration levels between LECs, LEC operators, and Distribution System Operators (DSOs). The study highlights the economic and operational trade-offs between different scenarios, with a focus on the balance between DSO-LEC costs and benefits. The study also highlights the importance of the location of LECs in the grid for voltage regulation and incentive allocation based on LECs contribution to solving voltage issues. Our findings show that LECs effectively reduce undervoltages, especially in winter. While their impact on overvoltages is currently limited due to seasonal mismatches between PV generation and load, increasing future loads may enhance their role in mitigating summer overvoltages.

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Table of contents

Terminology

Term	Definition/Explanation
Implicit Flexibility	Load shifting in response to electricity prices or tariffs, not through direct control.
Distribution System Operator (DSO)	An entity responsible for operating, maintaining, and developing the distribution grid for electricity.
Local Energy Community (LEC)	Legal entities that provide environmental, economic or social benefits to the local community by participating in activities like power generation, distribution and consumption.
Active Measure	Grid planning measure that involves the active utilization of resources in the system during system operation[8]
Passive Measure	Traditional grid planning measure (not an active measure) such as power line upgrade
Customers/Consumers	Individual grid users that consume electric energy.
Subscription Level for LEC	The agreed level of energy consumption for an LEC under a subscription-based tariff model.
Investment Cost/Line Upgrade Cost	The cost incurred in upgrading the power lines
Flexibility	The ability and willingness to modify generation injection and/or consumption patterns, on an individual or aggregated level, often in reaction to an external signal, in order to provide a service within the energy system or maintain stable grid operation[1].
Active Distribution System Operator	A DSO that plans for using active measures as well as passive measures to manage their system.
Passive Distribution System Operator	A DSO that only plans for using passive measures to manage their system.
Incentives	Financial motivations provided by DSO to encourage LEC, for peak load reduction.
Grid Fees	Charges levied by DSO for the use of the electricity grid infrastructure.
Energy Tariff	The pricing structure for electricity supply, often including fixed and variable charges.
Subscription Tariff	A tariff model where LECs pay based on a subscription level rather than only usage.
Dimensioning Day	A specific day identified for analysis, including hours with maximum and minimum voltages in case of overvoltage and undervoltage, respectively.
Dimensioning Hour	A specific hour of operation with maximum and minimum voltages in case of overvoltage and undervoltage, respectively.
Voltage Regulation	Process of maintaining the voltages within the limits i.e., above 0.95 and below 1.05 p.u. for medium voltage distribution grid.
Demand Response	Strategies to adjust the demand for electricity in response to tariffs or market conditions.
Operational Cost of Local Energy Community	The total expenses incurred by an LEC in managing and operating its energy generation and consumption, including the cost of electricity bought and export at spot prices and the grid tariffs.

[1] G. Kjølle, K. Sand, and E. Gramme, 'Scenarios for the future electricity distribution grid', in *CIRED 2021 Conference*, Geneva / virtual, 2021, p. Paper 0858.

1 Introduction

The electricity distribution system is developed with the purpose of facilitating grid access to all grid users and actors in a technically and economically sound manner. Traditionally, the system was considered to consist only of grid assets, and the measures considered by distribution system operators (DSOs) in developing the system was limited to passive measures such as installing new grid assets. Today new entities and actors are being integrated to the system, such as local energy communities (LECs) and LEC operators, and the distribution system needs to be operated in a more active manner involving more interaction between such actors. LECs are composed of a group of consumers who possess a combination of distributed energy resources. These can include photovoltaic (PV) systems, electric vehicles (EVs), flexible loads, and battery storage.

Figure 1 represents the communication dynamics in a distribution grid where emerging actors, such as LECs, interact with the DSO. These actors are at the forefront of adopting innovative technologies, which enable them to contribute to the system's flexibility as depicted by the signal flows. The LECs receive both incentives and grid fees from the DSO as a result of their active engagement in adjusting energy consumption patterns. This adjustment includes increasing, reducing, or shifting their net energy consumption to address grid constraints effectively. In contrast, non-LECs primarily receive signals related to grid fees, reflecting a more traditional interaction with the grid.

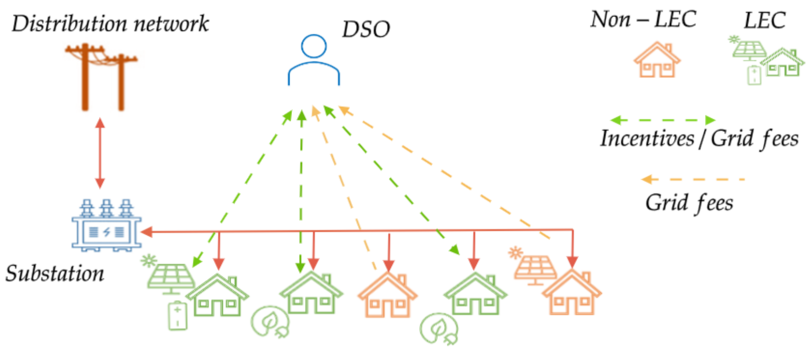

Figure 1: Illustration of incentive and activation signal transfer between Non-LEC, LEC and DSO.

Within the scope of our project, we have established four scenarios (***Business as usual, Local Coordination, Efficient Market, Integrated Units)*** that outline the interaction between LECs, LEC operators, and DSOs and their operation. The purpose of this work is to analyse how LECs can be used as a resource for DSOs to improve their planning activities and the societal benefits in the Business as usual, Local Coordination, Efficient Market.

Along these lines, the objectives of this work are:

1. Quantify costs and benefits of integrating LECs into the grid planning and grid operations.
2. Analyse the transition from a passive DSO to an active DSO model, focusing on the implications for voltage management.

In addition to this, to address the objectives, we have made certain assumptions:

- LECs are simplified representations within our model, with their loads and generation aggregated for simplicity.
- The range of flexibility from each LEC is bounded between 0 MW and 0.2 MW. For e.g.: Load cannot be shifted more than 0.2 MW at a specific hour.
- The flexible load is 20% of the original load for each LEC.

In this report, we explore three distinct scenarios that are elaborated in detail in Chapters 2 and 3:

1. Business as usual (reference scenario): There is no active engagement with LEC operators, and the DSO only considers passive measures, such as power line upgrades. LECs are passive in this scenario. They do not shift their loads in response to any signals or requests from the DSO.

2. Local Coordination: In this scenario, the DSO issue price signals through grid tariffs. LECs coordinate internally to respond to these signals, optimizing their subscription levels and daily operations of Distributed Energy Resources (DERs) accordingly. Exceeding subscription levels leads to higher tariffs, incentivizing the LECs to manage their peak loads and thus indirectly reducing the need for the DSO making extensive grid investments.

3. Efficient Markets: In contrast to the previous scenarios, DSO aim to minimize power line upgrade costs by considering both the cost of grid investments and the flexibility offered by LECs. The DSO plays an active role in this scenario, both in telling the amount of flexibility required and in calculating the necessary flexibility hours. DSO providing LEC operators with specific prices for activating flexibility services aimed at peak load and grid investment reduction.

2 LEC Integration in Distribution Grid for Undervoltage Management Under Local Coordination Scenario

2.1 Problem overview

In this work, we are taking a long-term perspective of the integration of LECs into the distribution grid. We aim to examine scenarios where, in the future, the grid may experience significant load increases, leading to overloads, peak demands, and undervoltage problems. LECs, equipped with flexible resources, could play a crucial role in this context. If the DSO provides them with a tariff based on their total load, allowing the LECs to utilize their flexible resources to reduce peak loads, it will benefit the DSO. This represents a form of implicit flexibility, where the DSO is not specifying exactly how much flexibility is needed from each LEC at any given time, but rather offering a tariff that incentivizes their participation.

Assumption:
For the DSO, our focus is on the costs associated with power line upgrades, viewed from a 10-year planning perspective. We have assumed that the DSO has information about the upcoming load connections and assesses the potential problems these connections might cause in the distribution grid, leading to power line upgrades. If new loads are being connected every two years, the DSO might upgrade the power lines every two years if that is their only available measure. However, we are aware that in practical settings, power line upgrades do not happen every two years, as it's a time-intensive process. Moreover, distribution grid power lines are in operation for more than decades e.g.: 30 years but we did not consider the lifetime of assets in this case study.
We aim to analyse a LEC having flexible resources and are motivated to reduce their grid import costs and are provided with a tariff structure that incentivizes them to reduce their peak loads. This approach is expected to reduce grid problems, such as undervoltage issues, and subsequently result in fewer power line upgrades for the DSO.

2.2 Methodology

In this section, we focus on the models we have developed to facilitate the comparison between the Reference scenario and the Local Coordination scenario. These models are made for the DSO and LECs to reflect the objectives under each scenario. Below is a table that outlines the objectives for the DSO and LECs in each of these scenarios.

Table 0: Scenario-Based Objectives for DSO and LEC.

Scenario	DSO Objective	LEC Objective
Reference scenario	Minimize the power line upgrade cost based on undervoltage problem (considering only power line upgrade measures)	LECs aim to minimize grid import cost, but without the incentive of special tariffs or active load management strategies. Consumers are billed individually.
Local Coordination scenario	Minimize power line upgrade considering both power line upgrade measures & flexibility from LECs	Actively minimize grid import cost by utilizing flexible loads, incentivized by a tariff structure based on the total capacity subscription level of the LEC.

In both scenarios, the objective of the DSO is to reduce the cost of power line upgrades and minimize undervoltages. Norwegian regulation on quality of supply in the power system dictate that end-user supply voltage values must not be below 0.9 p.u.[2] Norwegian DSOs therefore often use as a planning criterion that the voltage in the medium voltage (MV) distribution grid should have a higher limit value, such as 0.95 p.u. To achieve this, we have developed an investment model which determine the number of power lines that require upgrades to ensure the voltage drop remains within acceptable limits, which is typically 0.05 (1-0.95) p.u. The goal is to select power lines such that the upgrade costs are minimized while still achieving the desired voltage values. Thus, the objective of the model is as follows:

$$\min C_y = \sum_{ij\ lines} (1 - \alpha_{ij}) c_{ij} l_{ij} \tag{1}$$

where, c_{ij} denotes the cost per length of a new power line between bus i and j. Moreover, l_{ij} denotes the length of power line between bus i and j, and α_{ij} is an binary variable (1 or 0) denoting the choice of power line reinforcement between two buses.

The main governing part of the investment model can be modelled with the following equation:

$$V_i = V_{i-1} - IZ \tag{2}$$

, where *Vi* represents the voltage at a given point, *I* is the current, and *Z* is the impedance. Addressing undervoltages can be achieved by either reducing the current to mitigate the voltage drop or by decreasing the impedance. For reducing impedance, the procedure involves the following steps:

1. **Identify Weak Links**: Determine the subset of power lines connected to the weakest bus with lowest voltage. This will highlight the most vulnerable parts of the grid where undervoltages are likely to occur.
2. **Calculate Voltage Drop**: For the subset of power lines identified in the first step, compute the voltage drop across each of these lines. This quantifies the extent of under-voltage issues on these specific lines.

Moreover, the voltage drops $\mathrm{v}_{i,\mathrm{t_w}}$, $\mathrm{v}_{\mathrm{j,t_w}}$ between two subsequent buses i and j, can be computed for old $\mathrm{w}_{ij,\mathrm{t_w}}$ and new lines $\hat{\mathrm{w}}_{ij,\mathrm{t_w}}$ using a distribution grid load flow as in the forward-backward sweep method. Here, $\mathrm{t_w}$is the dimensioning hour (with the most severe voltage problems).

$$\mathrm{v}_{i,\mathrm{t_w}} - \mathrm{v}_{\mathrm{j,t_w}} = \mathrm{w}_{ij,\mathrm{t_w}} \ \forall\, ij \tag{3}$$

$$\hat{v}_{i,\mathrm{t_w}} - \hat{v}_{j,\mathrm{t_w}} = \hat{\mathrm{w}}_{ij,\mathrm{t_w}} \ \forall\, ij \tag{4}$$

$$\sum_{ij\ in\ l(i_w)} \alpha_{ij} * \hat{\mathrm{w}}_{i,\mathrm{t_w}} + \sum_{ij\ in\ l(i_w)} (1 - \alpha_{ij}) * \mathrm{w}_{ij,\mathrm{t_w}} \leq 1 - v_{i_w^{limit}} \tag{5}$$

where $v_{i_w^{limit}}$ is the voltage that we want to achieve for the weakest bus.

[2] Regulations Governing Quality of Supply in the Power System (Norwegian: Forskrift om leveringskvalitet i kraftsystemet), Ministry of Petroleum and Energy, 2020, https://lovdata.no/dokument/SF/forskrift/2004-11-30-1557.

In local coordination scenario, the LEC is subject to an aggregated capacity subscription tariff model. This gives advantageous coordination effects, as the grid tariff is designed to incentivize demand response from the entire LEC as an entity. The grid tariff introduces a cost structure based on their total subscribed capacity. This approach ensures that the tariff is applied to the collective capacity of the LEC as a whole, rather than billing each individual LEC member. This in turn means that the LEC will consider the coincidence factor from the load profiles of the individual LEC members and hence only trigger demand response from a single LEC member asset when necessary. Grid tariffs on an aggregated level has proven more efficient than individual tariffs in previous works[3,4,5]. The methodology involves the following steps:

1. **Define Capacity Subscription Level:** LECs determine a specific capacity level P^{sub}, based on their forecasted demand profile. Despite higher cost for overusage, it will usually be optimal to have some over-usage for peak load with short durations rather than subscribing to the maximum load unless the maximum load has a sufficiently long duration to make it more economical to subscribe.
2. **Set Tariffs for Consumption Levels:**
   - **Below Subscription Level:** For power consumed below the subscription level (P_t^l) a minor energy charge, is charged (C^l). This rate accounts for the grid's marginal losses.
   - **Above Subscription Level:** Consumption that exceeds the defined subscription level (P_t^h) is charged at a much higher rate (C^h),
3. **Calculate Total Grid Tariff Costs:** The complete grid tariff costs for LECs can be summarized with the equation:

$$C_{GT} = \sum_t P_t^l C^l + P_t^h C^h \tag{6}$$

The pricing model currently implemented in Norway does not have the overusage possibility included here, and instead of selecting a subscription level the enduser is billed based on the maximum observed load. The implementation here can also represent this by setting the overusage cost, (C^h), higher than the subscription cost, C_{sub}, making it more economical to subscribe for all load durations and thus no overusage.

LEC flexibility: By utilising load shifting, LECs adjust their energy consumption patterns to keep the net import below their subscribed levels as much as possible and possibly also change their optimal subscription level. As depicted in the figure, the LEC's forecasted original consumption profile is represented by the blue plot, which shows their forecasted energy consumption for 24 hours. The dotted line indicates the LEC's subscription level. At certain times, this forecasted consumption might exceed the subscription level, leading to higher costs. To avoid this, the LEC employs load shifting. The red plot in the figure illustrates how the LEC adjusts its consumption patterns using flexibility. By shifting some of the load to different hours, the LEC ensures that its energy consumption remains within the boundaries of the subscribed level, avoiding the extra charges. This helps them avoid the higher tariff associated with exceeding their subscription.

[3] Backe, S., Kara, G., Tomasgard, A., 2020. Comparing individual and coordinated demand response with dynamic and static power grid tariffs. Energy 201, 117619. https:// doi.org/10.1016/j.energy.2020.117619

[4] Askeland M., Backe S., Bjarghov S., Korpås M.. Helping endusers help each other: coordinating development and operation of distributed resources through local power markets and grid tariffs. Energy Economics. https://doi.org/10.1016/j.eneco.2020.105065.

[5] Bjarghov S, Askeland M, Backe S. Peer-to-peer trading under subscribed capacity tariffs - an equilibrium approach. In: 17th international conference on the European energy market. EEM); 2020. https://doi.org/10.1109/ EEM49802.2020.9221966.

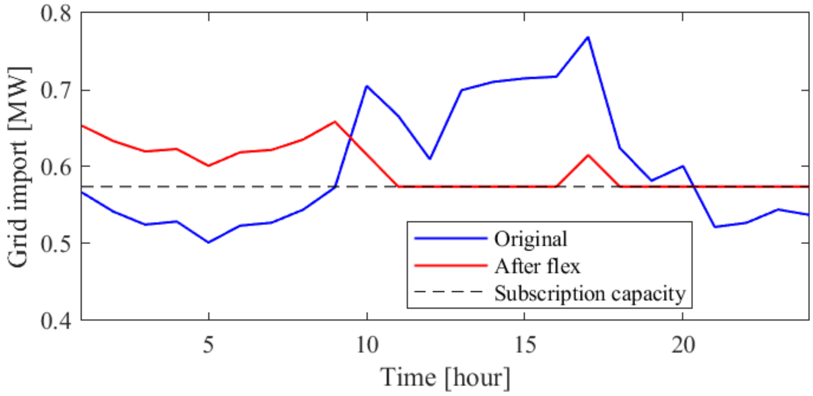

Figure 2: Conceptual Illustration of subscription-based tariff.

2.3 Case setup

We consider a 10-year power system planning case for a distribution system shown in Figure 3: the CINELDI MV reference system. This is a representative Norwegian radial, medium voltage (22 kV) distribution system with 124 buses. The reference data set includes a set of hourly load time series for a full year for all 54 load points that exist in the "base" version of the reference grid that represents the present-day system. Each load point represents a distribution substation, and the underlying low voltage (LV) distribution grids are not included in the grid model. The annual peak load demand in this base system is 5.23 MW. It is assumed that the DSO has scenarios for when new loads are expected in the system and their expected annual peak load, aggregated to the individual MV/LV distribution substation. Each LEC is assumed to have an annual peak load value of 0.88 MW. An overview of when and where these new loads are added to the system is shown in Table 1. Since the MV reference grid mainly has undervoltage related issues, we focus on identifying the hour when voltage conditions are most demanding i.e, the hour during which the grid experiences the lowest voltage. This information is crucial for DSOs to make informed decisions regarding grid upgrades and demand-side management mechanisms. Table 2 provides an example of the variation in the number of hours for the considered distribution grid, indicating voltage problems.

Table 1: Investigated load development scenario.

Year	Bus number
1	89
2	104
4	65
7	30
9	38

Table 2: Overview of undervoltages with no measure.

Year	Number of hours (voltages<0.95 p.u.)	Voltage for weakest bus (96)	Dimensioning hour
2	71	0.9418	8585th
4	278	0.9348	8585th
7	902	0.9324	8585th
9	1362	0.9291	8585th

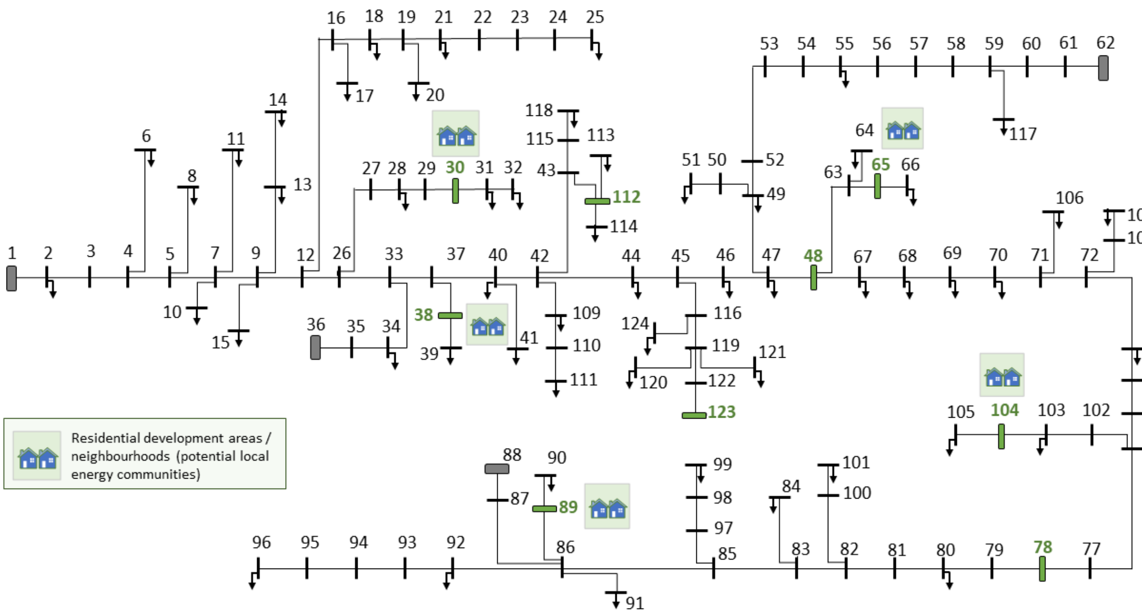

Figure 3: Reference system representative for a Norwegian radial, MV distribution systems (the CINELDI MV reference system).[6]

2.4 Simulation

After identifying the dimensioning hour, we conducted our first simulation for the reference scenario. In this simulation, we initially ran the investment model for the dimensioning hour in year 2 to identify which power lines needed upgrading to achieve a voltage of 0.95. Subsequently, we upgraded these power lines, meaning we altered the resistance and reactance in our input data, and then ran the investment model for the 8585th hour in year 4. We again find out which power lines need to be upgraded. Since the investment model indicates which power lines to upgrade in order to maintain a voltage of 0.95, these power lines are not sufficient due to new LECs connecting to the distribution grid, as shown in Table 2.

We have then repeated this process for year 7, using the solutions from year 4, which included updated impedance, in the investment model. In this scenario it is assumed that LEC load is not flexible, and the only measure DSO has is to upgrade the power lines. Table 3 shows the power line upgrade costs for these simulations.

We then conducted simulations for the local coordination scenario. In this scenario, we first ran a model for the LECs, aiming to reduce their grid import costs because of the subscription tariff. Under this tariff, if they exceed their subscription level, they will incur higher payments. Therefore, they attempt to use their flexible resources to keep their demand flat and reduce their peak loads. After running this model, we used the LEC profile for the dimensioning hour, the 8585th hour of year 2. Up to this year, the LECs at buses 89 and 104 both contribute to the grid. During the dimensioning hour, we took the LEC's load and then ran the power

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[6] I.B. Sperstad, O.B. Fosso, S.H. Jakobsen, A.O. Eggen, J.H. Evenstuen, G. Kjølle, Reference data set for a Norwegian medium-voltage power distribution system, *Data in Brief*, p. 109025, Mar. 2023, doi: 10.1016/j.dib.2023.109025.

line investment model to determine if the LEC's contribution brings the voltage up to 0.95. However, LEC's new load is not sufficient, and we need to upgrade the power lines. The cost incurred in this scenario is given in Table 3.

Similar to the reference case, for running the simulation for year 4, we use the impedance of the power lines in year 2 and upgrade the power lines before running the simulation for year 4.

However, if we look at year 9, the cost in the reference scenario is 0.218 MNOK, whereas the cost in the coordination scenario comes to 0.241 MNOK. This is because we upgraded fewer power lines, and it is possible for LECs that they can't reduce the peak during the dimensioning hour. For example, the LEC at bus 30, which arrives in year 7, may not be able to reduce its peak as discussed later in the simulation studies, leading the DSO to undertake more line upgrades in year 9. This contrasts with the reference scenario, where power lines with lower impedance are identified from the beginning to maintain voltage levels.

Table 3: Power line upgrade and Present value cost to DSO in different scenarios.

	Reference scenario		Local coordination scenario	
	Power line upgrade cost (NOK)	Power line upgrade present value (NOK)	Power line upgrade cost (NOK)	Power line upgrade present value (NOK)
2	1279712	1230302	798704	767225
4	793220	720669	710250	645308
7	294968	250620	294968	250620
9	218945	176513	241778	194664
Total		**2378104**		**1857817**

Table 3 investigates the financial implications by comparing the present value of power line upgrade costs for both scenarios. We calculate the present value of the line upgrade cost assuming a discount rate (r) of 4% using the formula given below:

$$\boldsymbol{Line\ upgrade\ present\ value} = \frac{\boldsymbol{Line\ upgrade\ cost}}{(\mathbf{1}+\boldsymbol{r})^{\boldsymbol{t}}} \qquad (7)$$

The analysis indicates a reduction of 0.52 MNOK (2.37-1.85) in line upgrade costs when utilising the implicit flexibility of LECs. This suggests that LECs shifting their energy usage can result in economic benefits for the overall grid infrastructure by mitigating the need for extensive grid investments.

Analysis of Grid Peak Load and impact on voltages

Figure 4 illustrates the peak grid load at the 8585th hour (dimensioning hour). The blue plot highlights the increase in peak load corresponding to the addition of new LECs. The red plot shows the effect of LECs utilizing their flexible resources to remain within subscription limits, which in turn reduces the aggregated peak load. Initially, only LEC 1 is active, achieving a 20% load reduction—based on the assumption of 20% load flexibility. As more LECs are integrated, they collectively contribute to a greater reduction in peak demand.

Figure 5 presents the load of the LECs at the 8585th hour. It is notable that not all LECs reduce their load at this specific hour. For instance, the LEC at bus 30 actually shows an increase in load upon responding to the subscription-level flexibility scheme. However, this increase is counterbalanced by the prior integration and load reduction efforts of LECs at buses 65, 89, and 104, ensuring an overall decline in the grid's peak load. In summary, the introduction of implicit flexibility through LECs' adherence to subscription levels can lead to a reduction in peak loads, provided there is a significant number of LECs in the system utilizing flexible load management. Under this implicit flexibility activation scheme, individual LECs independently adjust their load profiles. As the LECs does not receive incentives or control signals related to the overall grid situations, it may be optimal for some of them to increase the load during system peak load, but the cumulative effect of several LECs can give substantial benefits for the grid as a whole.

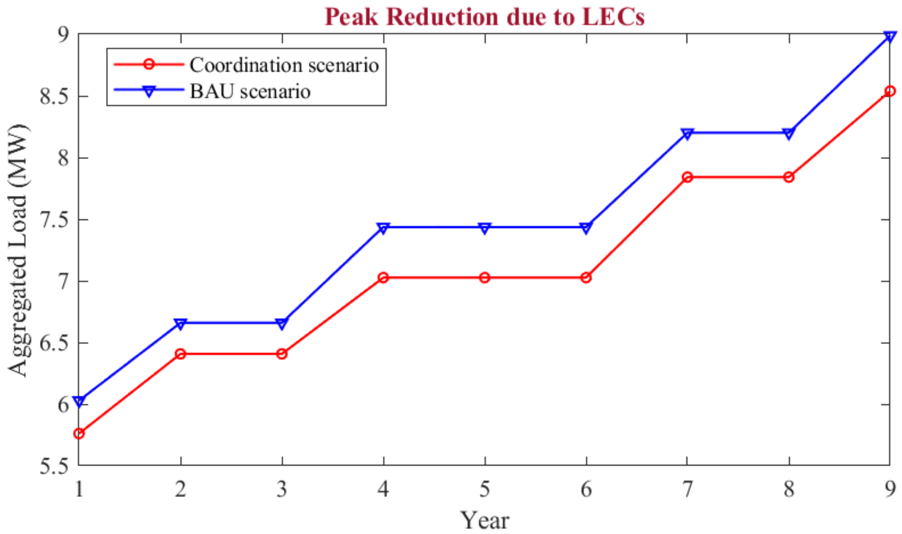

Figure 4: Aggregated peak load at 8585th hour (dimensioning hour).

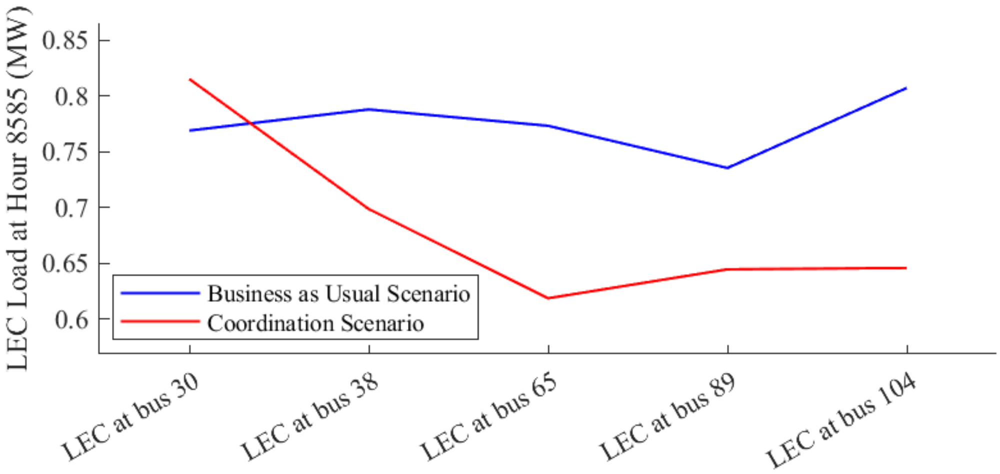

Figure 5: Individual LEC load at 8585th hour (dimensioning hour).

Figure 6 illustrates the impact on voltage levels in both the reference and local coordination scenarios when a DSO conducts year-ahead analyses. The purpose of these analyses is to anticipate potential under-voltage problems. By doing so, the DSO can implement measures to prevent these anticipated issues. This figure effectively demonstrates how different scenarios influence voltage regulation in the grid.

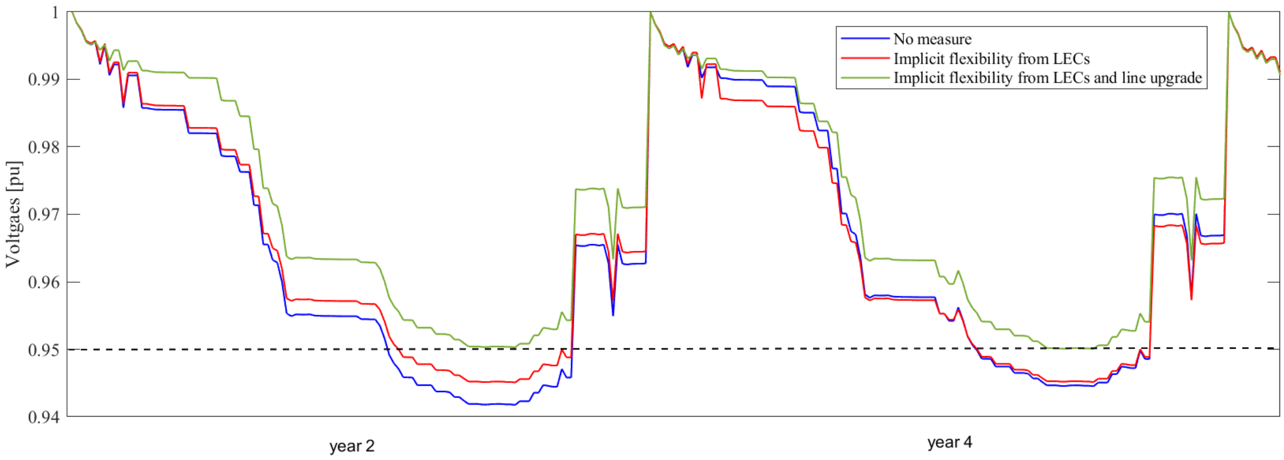

Figure 6: Comparison of variation of voltages for all buses in the grid for the dimensioning hour.

Figure 6 shows the voltages of all buses during the dimensioning hour. The blue curve represents the scenario after the LEC has connected and the DSO has noticed undervoltage problems, which are around 0.941 p.u. Then, in the local coordination scenario, which involves implicit flexibility from the LEC, the voltages improve to 0.948 p.u. However, the voltages are still below the desired voltage limit, so we have upgraded the power lines, as shown by the green curve, bringing the voltages up to 0.95 p.u.

In year 4, a new LEC arrives, and the voltages again fall below 0.95, as shown by the blue curve. However, these voltages in blue curve are higher than year 2 because of power line upgrade already made. And now implicit flexibility from LECs improves the voltages very little as seen in red curve for year 4.

Cost and Benefits of LEC: Now we will discuss the benefits for the LEC. First, we looked at the operational cost for the LEC if it receives the current energy tariff from the DSO. The energy tariff has a fixed component, which is a monthly charge, and a variable part that changes according to summer and winter rates. The tariff structure is provided in Table 4. Using this tariff, we calculated the cost, which is presented in Table 5. The fixed part of the cost was calculated as 12 * Fixed cost * Number of customers. For the variable part, we multiplied the LEC's demand profile (kWh) by the tariff rate to determine the cost.

Table 4: Energy Tariff.

Energy Tariff	Value
Tariff import inclusive VAT and tax (summer)[7]	38.5 øre/kWh
Tariff import inclusive VAT and tax (winter)	41.74 øre/kWh
Fixed cost	250 (kr/mnd)

[7] https://lede.no/getfile.php/1342165-1641466899/Lede/Priser/Priser%20for%20bolig%20og%20fritidsbolig%202021.pdf

Table 5: Annual Operational cost of LEC (Only Energy Tariff related cost).

LEC	Number of customers	Fixed (NOK)	Variable (NOK)	Total (NOK)
LEC at bus 30	185	638250	1221309	1859559
LEC at bus 38	206	710700	1358879	2069579
LEC at bus 65	201	693450	1326166	2019616
LEC at bus 89	220	759000	1443891	2202891
LEC at bus 104	133	458850	873453	1332303

The cost calculated from the energy tariff shown in Table 4 serves as a reference. It's crucial that if the DSO introduces a subscription tariff and the LEC does not utilize any flexibility, then the cost incurred under this subscription tariff should be equivalent to the cost under the energy tariff. This equivalence is necessary to ensure that the new tariff scheme does not result in a loss for the DSO.

In our model, we keep the subscription level as a variable and start with initial estimates for C^h, C^l, and C_{sub}. We then calculate the cost for each LEC, initially assuming there is no flexibility from LECs. The tariff components are adjusted after every iteration. The iteration process continues until the cost for the LEC under the subscription tariff matches the cost under the energy tariff. Once this equilibrium is achieved, we have our finalized tariff components. The final subscription levels and the tariff components have been shown in Table 6 and Table 7 respectively.

Table 6: Optimal Subscription level determined from optimisation model.

	Without Flex (MW)	With Coordination/Flex (MW)
LEC at bus 30	0.59	0.57
LEC at bus 38	0.66	0.64
LEC at bus 65	0.64	0.62
LEC at bus 89	0.61	0.57
LEC at bus 104	0.47	0.40

Table 7: Subscription Tariff.

Subscription Tariff	Value
C^h	2.41 (NOK/kWh)
C^l	0.38 (NOK/kWh)
C_{sub}	1125 (NOK/year)

In Table 8 , we are presenting the annual operational costs for LECs, where we have shown both the spot price-based cost and the tariff-based cost.

Remark: If we look at the cost under the subscription tariff in the '**Reference**' heading, it is nearly the same as the column under '**Total**' in Table 5. This is what we were discussing earlier that the cost incurred under this subscription tariff should be approximately equivalent to the cost under the energy tariff.

Table 8: Annual operational cost for LECs with and without coordination.

LEC (at bus)	Reference scenario			Local Coordination Scenario			
	Spot price (NOK)	Subscription Tariff (NOK)	Total (NOK)	Spot price (NOK)	Subscription Tariff (NOK)	Total (NOK)	Savings (NOK)
LEC1 (at bus 30)	2884486	1852962	4737448	2877830	1811199	4689029	48419
LEC2 (at bus 38)	3234535	2059341	5293876	3218936	2018182	5237118	56758
LEC3 (at bus 65)	3102195	2003206	5105401	3088949	1965309	5054258	51143
LEC4 (at bus 89)	3482959	2082104	5565063	3461039	2016212	5477251	87812
LEC5 (at bus 104)	2204180	1435361	3639541	2184257	1324712	3508969	130572
Cumulative	**14908355**	**9432974**	**24341329**	**14831011**	**9135614**	**23966625**	**374704**

In Table 8 , we have also quantified the benefits for the LECs when using flexibility under the coordination tariff. The table includes a column called ***'Savings'****, which represents the difference in total cost between the two scenarios. We can observe that all LECs are experiencing savings, ranging from 0.048 MNOK to 0.13 MNOK.*

Remark: It is important to note that these savings calculations do not account for the costs incurred in implementing these flexibility measures. For example: Implementing flexibility measures reduced LEC 5's annual operational costs from 3,639,541 NOK to 3,508,969 NOK, saving 0.13 MNOK. However, this doesn't include the extra initial and maintenance costs of these measures.

Comparison of DSO costs and revenue:

So far, we have seen that the coordination scenario benefits the DSO in terms of improved voltage and peak reduction, and it also aids the LECs by reducing their grid import costs.

The next aspect to explore is whether the DSO can offset the decrease in revenue resulting from the LECs' reduced grid import costs. The tariff collected from the LECs comprises a substantial portion of the DSO's revenue. Therefore, a reduction in LECs' costs equates to decreased income for the DSO. However, it's also important to consider that by reducing peak loads and assisting in mitigating undervoltage problems, the LECs contribute to a reduction in power line upgrade costs. The critical question now is whether this cost saving from power line upgrades can effectively compensate for the DSO's lost revenue due to lower tariffs from the LECs.

The DSO's savings from power line upgrade costs due to coordination are reflected in the difference in the present value of the power line upgrade costs between the Reference and Local Coordination scenarios. From Table 3, this saving is 2.37 MNOK−1.80 MNOK=0.52 MNOK

Table 9: Present value of revenue to DSO in different scenarios.

Year	Reference scenario		Local coordination scenario	
	Revenue (NOK)	Present Value Revenue (NOK)	Revenue (NOK)	Present Value Revenue (NOK)
1	2082104	2001635	2016212	1938089
2	3517465	3251989	3342924	3084262
3	3517465	3139832	3342924	2977963
4	5521671	4746036	5310233	4555030
5	5521671	4473995	5310233	4288176
6	5521671	4217295	5310233	4036131
7	7374093	5737967	6945432	5409074
8	7374093	5420737	6945432	5103344
9	9437364	6844374	8729114	6325082
10	9437364	6462055	8729114	5956132
Total		**46295915**		**43674283**

The impact on DSO's revenue due to coordination is the difference in the present value of revenues between the two scenarios. From Table 9, this is 46.29 MNOK−43.67 MNOK=2.62 MNOK

Although the DSO's cost savings of 0.5 MNOK are less than the 2.62 MNOK reduction in revenue due to coordination tariff, it is essential to consider that we have not factored in the costs associated with implementing flexibility in LECs' operations. In summary, while the DSO realizes some cost savings from coordination tariff, these savings alone does not completely offset the reduction in revenue in this analysis. However, this evaluation does not take into account the possible expenses that LECs may incur in order to attain flexibility, which could lead to a more detailed and refined financial analysis.

3 LEC Integration in Distribution Grid for Undervoltage Management Under Efficient Market Scenario

3.1 Problem Overview

This problem focuses on incentive-based demand side management strategy for reducing undervoltage problems in the grid. Procuring flexibility from the LECs can be effective way to reduce high consumption periods, thereby lowering the strain on the grid. However, in case of several LECs within the DSO's purview, there could be a challenge of procurement of optimal amount of flexibility from each LEC distributed at different nodes in the power grid. For instance, the geographical location of the LECs in the power grid can be a major factor in choosing the flexibility required at any particular time. Intuitively, the LECs closest to the *weakest bus* should be called upon the most. However, at times of extreme voltage drop issues, the challenge would be to estimate the involvement of multiple LECs for flexibility (or curtailment) requirements. More so, the incentive distribution to multiple LECs should consider the fair value of their contribution in reducing the voltage issues for the DSO. From the DSO's perspective, the incentive allocation should not be more expensive than the potential cost savings of power line upgrade. This requires a critical balance between choosing the level of flexibility provisions from LECs, and necessary power line upgrades thereafter.

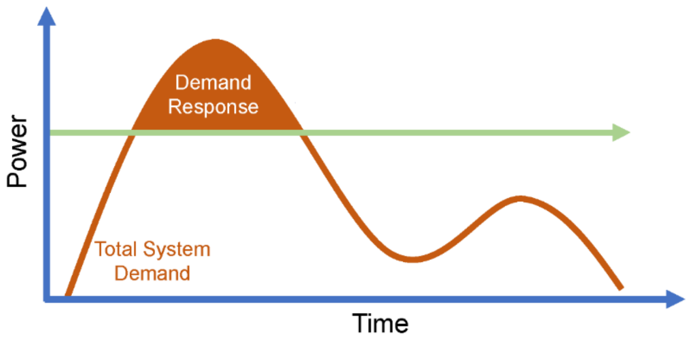

Figure 7: Flexibility provisions of peak reduction from LECs for undervoltage mitigation.

Figure 7 shows flexibility provision for the undervoltage reduction in a distribution grid. The aim of this is to provide an hourly resolution settlement of incentives for each LEC, under a fair and stable settlement mechanism considering the savings in power line upgrade costs.

Assumptions:
To approach the aforementioned problem, we focus on estimating the percentage reduction of customer energy consumption necessary as compared to the benefits of power line upgrades. The assumption in this approach is to consider that the customers (within a LEC) would be accepting of a contractual obligation to reduce/shift their pre-defined power consumption at any time required from the DSO.

However, using suitable prediction mechanisms for upcoming violations of voltages at weak buses, the DSO may give the LECs day-ahead signals for procuring the flexibility and reducing or flattening their energy consumption profiles. An underlying assumption in our analysis is that all LECs are presently connected, and no additional connections are anticipated for several years. It is assumed that these LECs are bound by a contract to provide flexibility for 'n' years. Therefore, the longer the duration of these contracts, the more extended the deferment of power line upgrades. This deferment specifically applies to those lines that are not being upgraded currently due to the utilization of flexibility provided by the LECs. Moreover, it is assumed that the incentive settlement is performed after the actual flexibility activation (as in the cases of balancing markets). The distribution grid may have several other energy consumers; however, the proposed methodology focuses only on specific buses with new LECs being connected at.

3.2 Methodology

In this section we discuss the method developed to compare cost and benefits to DSO and LECs in reference and efficient market scenarios.

For an efficient market scenario to function optimally, the fundamental research questions to be investigated are given below. We try to frame these questions from the perspective of the DSO. Central to this work are the main Key Performance Indicators (KPIs) focused on flexibility: 1) the amount of flexibility required, 2) the specific hours when flexibility is needed, and 3) the fair value of incentives for providing this flexibility. Keeping these KPIs in mind, our research questions have been formulated to address these crucial aspects.

1. What is the level of flexibility activation (in MW/hour) required from each LEC?
2. How often do we need flexibility from LECs to reduce undervoltage problem?
3. How are the incentives allocated among LECs for the participation in reducing undervoltage problem?

Our model of an active DSO is a DSO conducting a comprehensive analysis to determine both the frequency and magnitude of flexibility required from each LEC.

Our model considers several key factors, such as the geographical location of the LECs, their proximity to the grid's most vulnerable or 'weakest' buses, and their cumulative impact on the distribution grid. For example, our model indicates that LEC 1, owing to its strategic location and minimal impact on the grid, may only need to be activated twice a year to meet the grid's flexibility requirements. Conversely, LEC 4, situated in close proximity to the weakest bus, could necessitate more frequent activations to maintain voltage within predefined limits. By adopting such a targeted approach, active DSOs can not only ensure more effective utilization of LECs but also prioritize infrastructure upgrades where necessary, thereby optimizing costs and enhancing the resilience of the distribution grid. The details of the methodology are explained using flowchart (Figure 8). Our methodology begins by connecting new residential loads, potential LECs, to the grid. The first step involves conducting a load flow analysis for the entire year. In this analysis, we focus on identifying the hours when voltages at the grid's weakest bus – the one farthest from the substation – drop below 0.95. We also determine the minimum voltage level reached, as this will be our dimensioning hour for calculating necessary power line upgrades.

To decide which power lines require upgrading during the dimensioning hour, we utilize an investment model, an optimization tool detailed in reference[8] and explained in the previous Chapter 2. This model helps us identify which power lines need to be upgraded to maintain voltages at or above 0.95 p.u. Assuming that the new residential loads have flexibility, we assume that they can reduce their load by 20% during the dimensioning hour and shift it to other hours. We will run this model again to estimate how much power line upgrade costs can be reduced by using this flexibility.

[8] Rubi Rana, Iver Bakken Sperstad, Bendik Nybakk Torsæter, Henning Taxt, ''Economic assessment of integrating fast-charging stations and energy communities in grid planning'', Sustainable Energy, Grids and Networks, Volume 35,2023,101083,ISSN 2352-4677,https://doi.org/10.1016/j.segan.2023.101083.

Our next step in the methodology involves assessing the impact of power line upgrades, identified after considering flexibility, on under-voltage problems. The DSO will upgrade these power lines to see how many under-voltage issues are resolved and how many remain. This assessment is crucial because LECs are distributed across different locations, and the DSO needs to determine the amount of flexibility required from each LEC and the specific hours when it's needed.

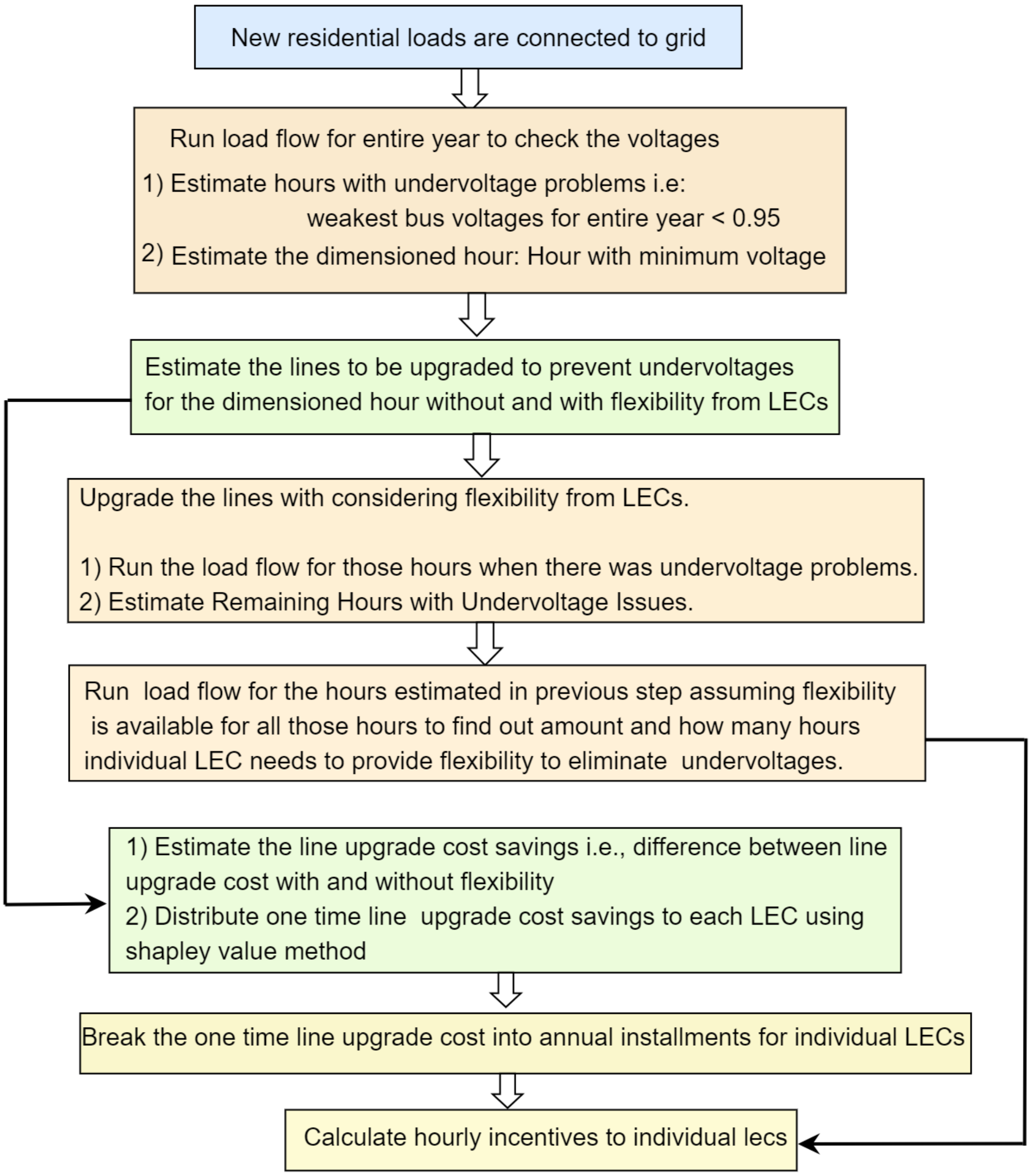

Figure 8: Flowchart for hourly incentive calculation for LECs.

Initially, we calculate the problem hours (denoted as 'x hours') caused by the introduction of LEC loads. After simulation with flexibility and power line upgrades, we re-evaluate to find out the reduced number of problem hours (denoted as 'y hours'). The difference, 'x-y hours', represents the remaining hours where undervoltage issues persist. For these remaining hours, our model will calculate the amount of flexibility required from each LEC and the hours for which it's needed. It is an iterative process as given below:

Estimate when and how much flexibility is needed from LEC

1. Initiate the process by utilizing flexibility from the LEC with the highest positive impact on voltage regulation. Assess the resulting voltage changes using load flow analysis.
2. Sequentially test the flexibility offered by each LEC to determine the minimum number of communities required to bring the voltage levels within the acceptable threshold.
3. Based on the above analysis, allocate specific hours to each LEC where their flexibility will be most effective in maintaining the voltage.

Power line upgrade cost savings distribution to each LEC using Shapley Value method

Upon identifying the costs (with and without flexibility from the LECs) for upgrading the power lines in Step 1, the subsequent step is for the allocation of the power line upgrade savings among the various LECs. The Shapley value method[9] will be utilised for this allocation which will ensure that every LEC will get incentives based on its contribution in voltage improvement. This method will not only consider the value each LEC adds to the overall savings by reducing peak demand (by shifting the demand to other hours) but also consider the impact each bus/node has on voltage improvement. For example, Figure 9 show an illustrative example of the contribution when all three LECs provide flexibility and there are cost savings (reduction in power line upgrade cost) of 0.5 MNOK. Bottom diagram shows the cost savings when only two LECs provide flexibility, thereby reducing cost savings to 0.2 MNOK. The profit attributed to LEC_3 can be approximated as the difference between case 1 and case 2, that is, 0.3 MNOK.

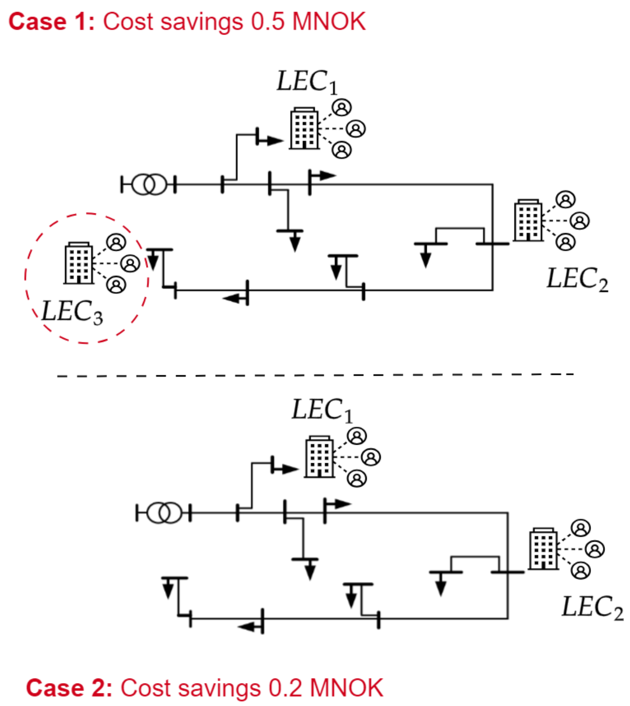

Figure 9: Illustration of Shapley Value concept.

[9] Voswinkel, Simon, et al. "Sharing congestion management costs among system operators using the Shapley value." *Applied Energy* 317 (2022): 119039.

We have now calculated a one-time cost for each LEC based on their contribution to voltage improvement. However, this compensation will not be provided in a lump sum. Instead, the DSO can defer power line upgrades for the duration of the LECs' contractual commitment, as mentioned in our earlier assumptions. To align with this arrangement, the DSO intends to break down this cost into annual instalments as explained in the steps that follow.

Breakdown of one-time cost into annual instalments

1. Assume the discount rate and duration of investment deferral (in years)
2. Calculate the future value of the power line upgrade cost savings allocated to each LEC based on their Shapley value.

$$FV = PV(1+r)^n \tag{8}$$

3. Break down into annual instalments for each LEC, again using the discount rate to discount future payments.

$$A = \frac{FV^r}{(1+r)^n - 1} \tag{9}$$

The final step of the methodology involves calculating the hourly distribution of incentives for each LEC, using the annual instalments determined previously and considering the specific hours and levels of flexibility needed from each LEC. This step combines the financial aspect (annual instalments) with the operational aspect (hours and level of flexibility required) to determine the incentives on an hourly basis.
Eg: Flexibility is required from an LEC during two specific hours in a year, and we want to calculate the incentive signal for hour 1,

$$Incentive_1 = \frac{P_1}{P_1 + P_2} * A \tag{10}$$

Where, P_1 and P_2 are the amount of flexibility (MW/hour) in hour 1 and hour 2 respectively.

3.3 Case Setup

In this case, we are using the same Figure 3 which is a representative Norwegian radial, medium voltage (22 kV) distribution system with 124 buses. The reference data set includes a set of hourly load time series for a full year for all 54 load points that exist in the "base" version of the reference grid that represents the present-day system. The annual peak load demand in this base system is 5.23 MW. Building on the general grid description, we place a special focus on the integration of LECs into this medium voltage (22 kV) distribution system. Specifically, LEC 1, LEC 2, LEC 3, LEC 4, and LEC 5 are connected to buses 30, 38, 65, 89, and 104, respectively. To provide a comprehensive view, we also examined the aggregated load profile for the entire grid, which includes not only the LEC-connected buses but also the other buses that form part of the 124-bus system. This aggregated profile as shown in Figure 10 serves as a background to better understand the specific impact of the LECs and identify the system's peak load and the hour at which it occurs.

These insights have proven to be instrumental for assessing the overall load dynamics of the grid and for identifying areas potentially vulnerable to under-voltage conditions.

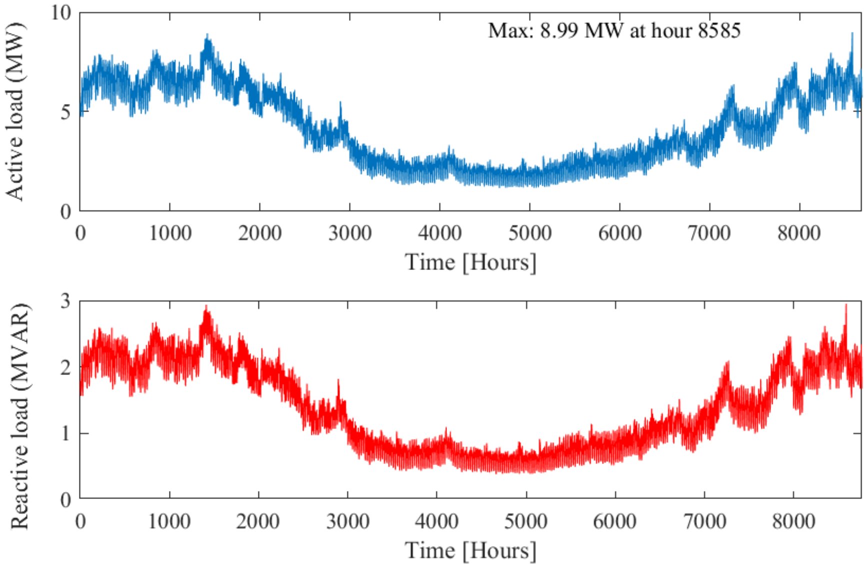

Figure 10: Aggregated Load Profile.

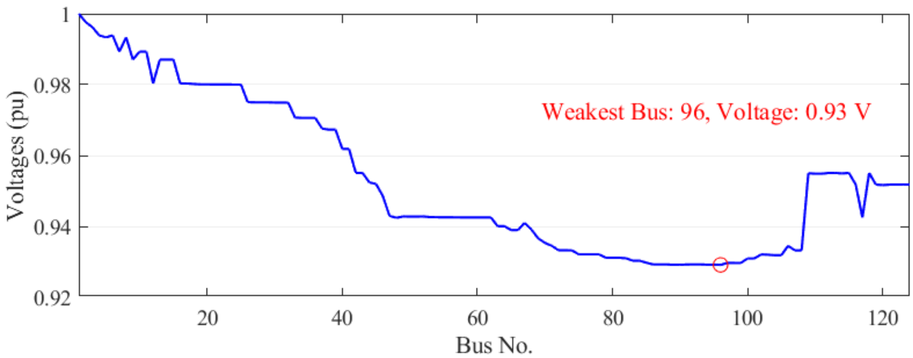

Figure 11: Voltage profile for entire grid corresponding to dimensioning hour.

We have examined the voltage levels across the entire grid during the peak load hour as shown in Figure 11. This allowed us to pinpoint the "weakest bus," which is the bus experiencing the most significant voltage drop. Identifying this bus is required for understanding which part of the grid is most susceptible to under-voltage issues. Upon identifying the weakest bus, we conducted a year-long analysis of its voltage levels and we find that there are 1392 hours the bus experience under-voltage conditions as highlighted in Figure 12. It is important to highlight that the x-axis index in the figure does not represent a chronological time series of hours. Instead, it signifies the cumulative count of those 1392 hours, arranged in a time duration curve format.

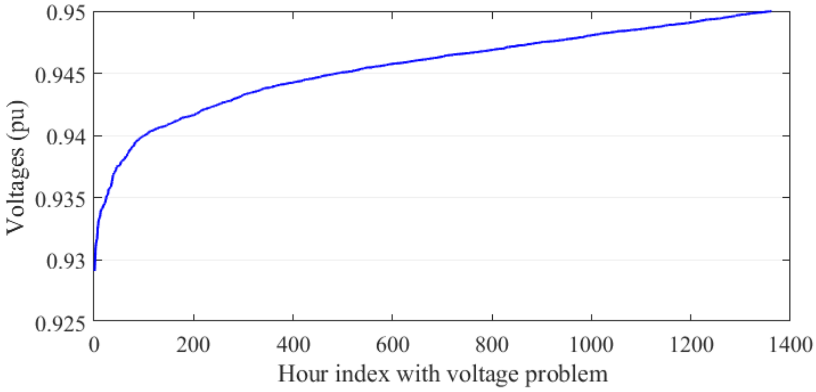

Figure 12: Number of hours with undervoltage problems.

3.4 Simulation

The results outlined in Table 10 present a comparison of investment costs—namely, the costs of power line upgrades—both with and without flexibility from LECs. There is an investment cost reduction of 0.72 million NOK when utilising flexibility from LECs. This underscores the economic benefit of utilising flexibility from LECs in managing undervoltage issues, showcasing its potential in facilitating more cost-effective and efficient grid upgrade strategies.

Table 10: Comparison of line upgrade costs under different scenarios.

Scenario	Line Upgrade Costs [MNOK]
Without Flex	2.57
With Flex	1.64
Cost Reduction	0.72

Figure 13 compares the voltage levels in different scenarios: without power line upgrade, with power line upgrade, and with both power line upgrade and flexibility. Without power line upgrade the number of hours with voltage problems are 1362 with the lowest voltage around 0.93 p.u. The main objective is to collaboratively utilise power line upgrades and the flexibility from LECs to sustain voltage levels above 0.95 p.u. at the lowest cost possible. Figure 13 shows the individual contributions of power line upgrades and flexibility and illustrates that employing both strategies simultaneously eliminates the hours with voltage problems, also indicating that the predominant contribution is from power line upgrades. Through the implementation of power line upgrades alone, the occurrence of voltage problems has substantially diminished from 1362 to 38 hours. To address these remaining 38 hours, an additional 20% flexibility has been deployed, effectively reducing the problematic hours to zero. Given that 20% represents the maximum assumed flexibility, it is pivotal only for mitigating the remaining 38 hours, necessitating power line upgrades for the other hours. Consequently, addressing these 38 hours using flexibility results in cost savings amounting to 0.72 million NOK, underscoring the economic efficiency of integrating both flexibility and power line upgrades in voltage regulation within the grid.

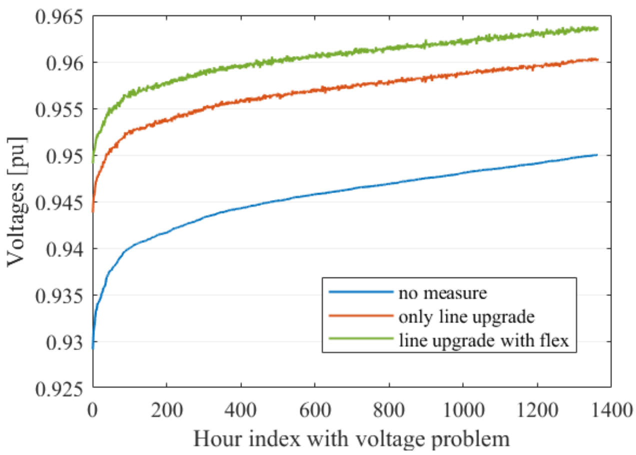

Figure 13: Voltages comparison without power line upgrade, with power line upgrade and with power line upgrade and flexibility from LECs.

The allocation of cost savings (of 0.72 MNOK) between the different LECs is shown in Figure 14. It may be noted that LEC 4 (Bus 89) received the highest incentive while LEC 1 (Bus 30) the least. This is because the fair allocation of cost saving incentives considers the contribution of individual LEC in improving the voltage at weakest bus (96). As LEC 4 (Bus 89) and LEC 5 (Bus 105) are closer in proximity to the weakest bus (96), 20% curtailment or time shifting their energy consumption provides more voltage improvement. Therefore, buses 4 and 5 receive the highest share of the overall cost savings of 0.72 MNOK. Whereas the farther away LEC 1 (Bus 30) and LEC 2 (Bus 38) receive a smaller payment as their contribution to voltage improvement is lower.

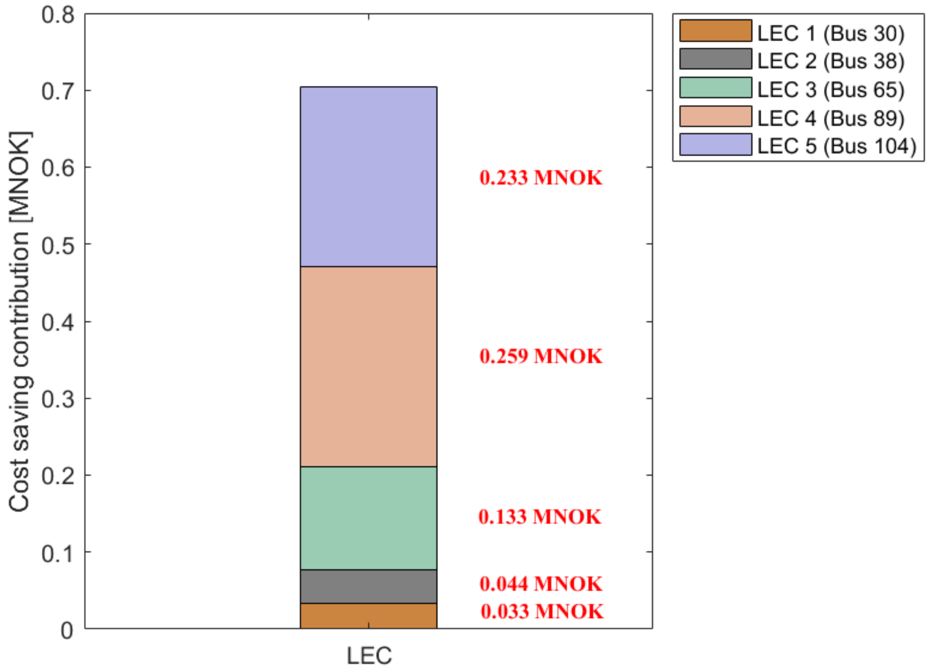

Figure 14: Cost savings distribution across LECs.

Table 11 illustrates the number of hours each LEC is required to provide flexibility, highlighting different requirements for each LEC. This is determined based on the LECs' locations within the grid and the consequent impacts on the grid. Moreover,

Figure 15 shows the level of flexibility needed from each LEC. The objective is to explore how the geographical positioning of LECs affects the calculated flexibility requirements needed to maintain the voltage level of the grid to 0.95 p.u. For instance, LEC 1, connected to bus 30, is situated distant from the most vulnerable bus. Consequently, its contribution is needed merely twice a year at most. This is because, for the remaining hours, the flexibility provided by other LECs is adequate to manage the system effectively. This also implies that these two specific hours are critically important, necessitating flexibility even from the LEC connected to bus that generally has the desired voltage level. It is to be noted that LEC-4 at bus 89 needs to activate the flexibility more times in a year compared to all other buses. This is due to its location within the grid and proximity to weakest bus. The total investment cost savings allocated to each LEC and each hour of activation is shown in Figure 16 for two of the LECs. The hourly cost allocation indicates a reasonable hourly incentive for activating flexibility from each LEC, assuming that the aggregated incentives to the LECs over the year should exactly cover the DSO's annualized investment cost savings.

Table 11: Hours of Required Flexibility Activation for Each LEC.

LEC	Number of hours flexibility is needed
1 (Bus 30)	2
2 (Bus 38)	5
3 (Bus 65)	10
4 (Bus 89)	38
5 (Bus 104)	20

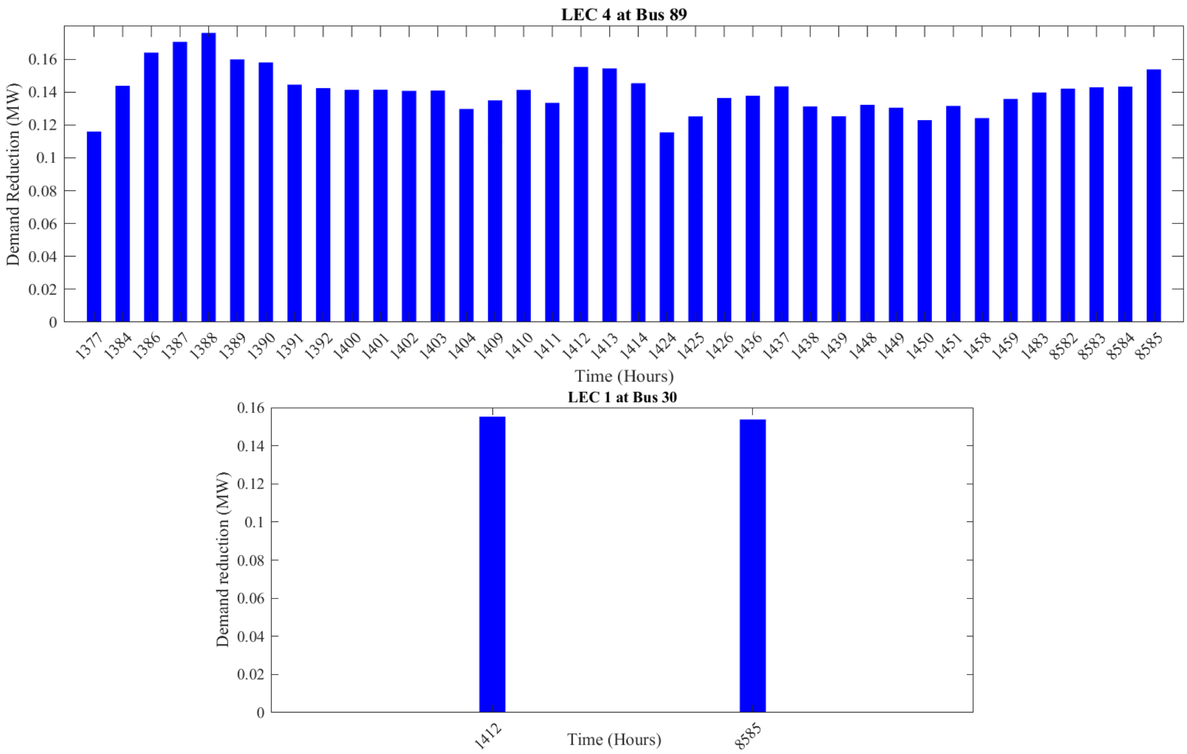

Figure 15: Flexibility provision required from each LEC (in form of demand reduction) at specific hours.

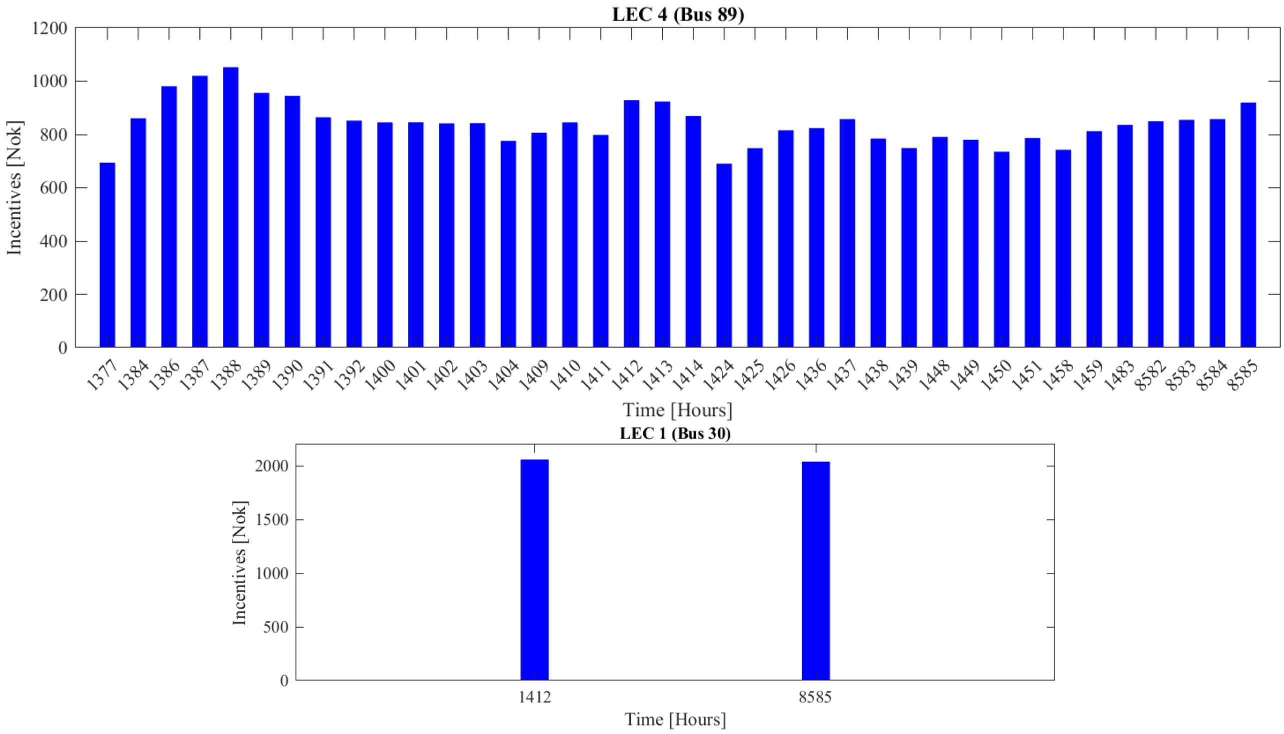

Figure 16: Hourly Incentives.

In Figure 17, a sensitivity analysis has been conducted. For this analysis, all loads were kept constant, and an additional load was introduced to each bus, one at a time. The analysis involved introducing an extra load to one bus at a time, across all 123 buses in the grid. For example, in the first simulation, the additional load was applied only to the first bus. We then investigated the necessary power line upgrade costs under two cases: one where the new load is flexible (can shift/reduce demand), and another where the new load is not flexible. This process was systematically repeated for each bus. On the x-axis of the figure, we have the bus numbers. The figure reveals that adding an additional load to buses closer to the substation is not cost-effective if this load becomes a part of a LEC in the future. This is indicated by the minimal difference in line upgrade costs between cases with the new load being flexible and not flexible.

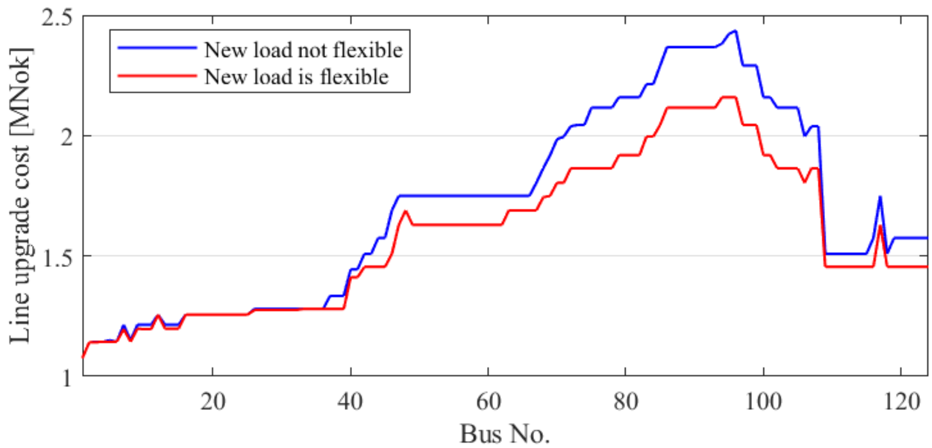

Figure 17: Comparison of Line upgrade costs with and without flexibility when additional load is placed on different buses.

4 LEC Integration in Distribution Grid for Overvoltage Management

4.1 Problem overview

In a radial distribution grid, integration of distributed energy resources (DER) can have a positive impact on the overloads and voltage conditions. The impact is most likely to be favourable for systems in which the installed DER capacities are on a similar level as the local power consumption. However, in a distribution system where the generation from DER exceeds the local load demand, reverse power flows occur toward upstream grid levels and are accompanied by voltage rises. These problems are compounded if DERs are solar photovoltaic (PV) or based on other variable renewable energy sources because of their intermittent nature.

To address grid problems arising from PV integration, conventional strategies include PV curtailment on the customer side, and power line upgrades on the DSO side. Implementing PV curtailment can stop the progress of renewable integration and result in economic losses for customers. A more ambitious and effective alternative for managing increased PV penetration would be availing flexibility from various collective assets. This includes utilising the potential of battery storage systems, electric vehicles (a non-critical, time-flexible load with high power consumption) and other flexible resources available within LECs. These resources can be employed to either shift or increase demand during periods of high PV generation.

Along these lines, this work investigates the following:

In Norway, there is a seasonal mismatch between PV generation and load demand, with higher PV generation in summer but lower load. The challenge lies in identifying an optimal demand-side management (DSM) strategy to manage this surplus production effectively. We want to investigate whether DSM strategy translate to self-consumption of PV energy increase, financial benefits increase for LECs, and power line upgrade reduction for the DSO.

4.2 Methodology

The proposed methodology is broadly divided into two parts: 1) DSM program for improving self-consumption of the LEC and, 2) Power line upgrade program.

For illustration purposes, the overarching idea behind the DSM program is shown in Figure 18, where the ‘Electricity Usage’ is assumed to be flexible (within a certain threshold).

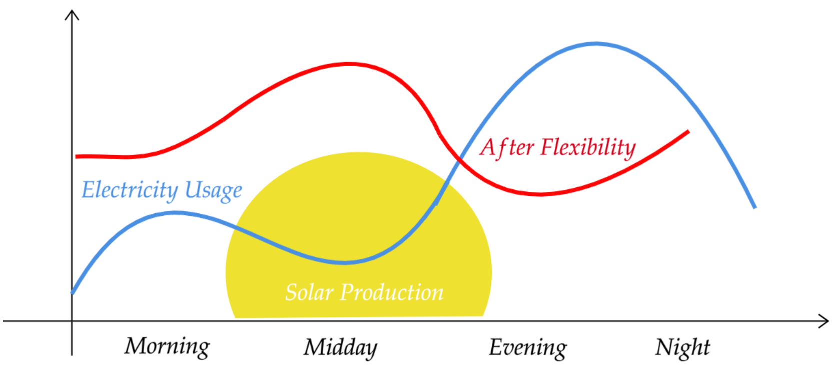

Figure 18: Using flexibility provisions to increase self-consumption of PV.

This allows us to shift some electricity demand from the evening time to the day-time with more of PV generation ('After-Flexibility'), in turn reducing the export of PV surplus to the grid. Therefore, this DSM strategy can indirectly help reduce the overvoltages in the grid.

Mathematically, it can be represented by minimising the difference between generation and load as follows:

$$\sum_{t=1}^{24}[P_{pv}(t) - P_{load}^{fixed}(t) - P_{load}^{flex}(t)]^2 \tag{11}$$

Where, $P_{pv}(t)$ is a PV generation time series for LEC, $P_{load}^{flex}(t)$ is the flexible load time series which is assumed to be 20% of the original load of LEC. $P_{load}^{fixed}(t)$ is the fixed load of LEC i.e., original load – $P_{load}^{flex}(t)$

In conjunction with the DSM strategy, the DSO would also be able to reduce the power line upgrade requirements through 'optimally' upgrading the power lines of the grid.

The objective of the investment model is the least-cost expansion of the distribution system under a strict voltage constraint at the weakest bus. It is assumed that power lines will be upgraded such that grid impedance reduces, thereby inducing reduced voltage increase at weak buses. The investment cost for power line upgrade can be minimized as follows:

$$Minimize\ C = \sum_{ij}(1 - \alpha_{ij}) * c_{ij} * L_{ij} \tag{12}$$

where c_{ij} denotes the cost per length of a new power line between bus i and j. Moreover, L_{ij} denotes the length of power line between bus i and j, and α_{ij} is an auxiliary binary variable denoting the choice of line reinforcement between two buses.

Moreover, the voltage rise $\mathrm{v}_{i,\mathrm{t_w}}$, $\mathrm{v}_{\mathrm{j},\mathrm{t_w}}$ between two subsequent buses i and j, can be computed for old $\mathrm{w}_{ij,\mathrm{t_w}}$ and new lines $\hat{\mathrm{w}}_{ij,\mathrm{t_w}}$ using a distribution grid load flow as in the forward-backward sweep method. Here, $\mathrm{t_w}$is the dimensioning hour (with the most severe voltage problems).

$$\mathrm{v}_{i,\mathrm{t_w}} - \mathrm{v}_{\mathrm{j},\mathrm{t_w}} = \mathrm{w}_{ij,\mathrm{t_w}}\ \forall\, ij \tag{13}$$

$$\hat{v}_{i,\mathrm{t_w}} - \hat{v}_{j,\mathrm{t_w}} = \hat{\mathrm{w}}_{ij,\mathrm{t_w}}\ \forall\, ij \tag{14}$$

$$\sum_{ij\ in\ l(i_w)} \alpha_{ij} * \hat{\mathrm{w}}_{i,\mathrm{t_w}} + \sum_{ij\ in\ l(i_w)} (1 - \alpha_{ij}) * \mathrm{w}_{ij,\mathrm{t_w}} \geq 1 - v_{i_w^{limit}} \tag{15}$$

where $v_{i_w^{limit}}$ is the voltage that we want to achieve for the weakest bus.

However, the power line upgrade should only be performed after analysing the voltage improvements from the DSM program. A flowchart given in Figure 22, highlights the flow of the proposed methodology.

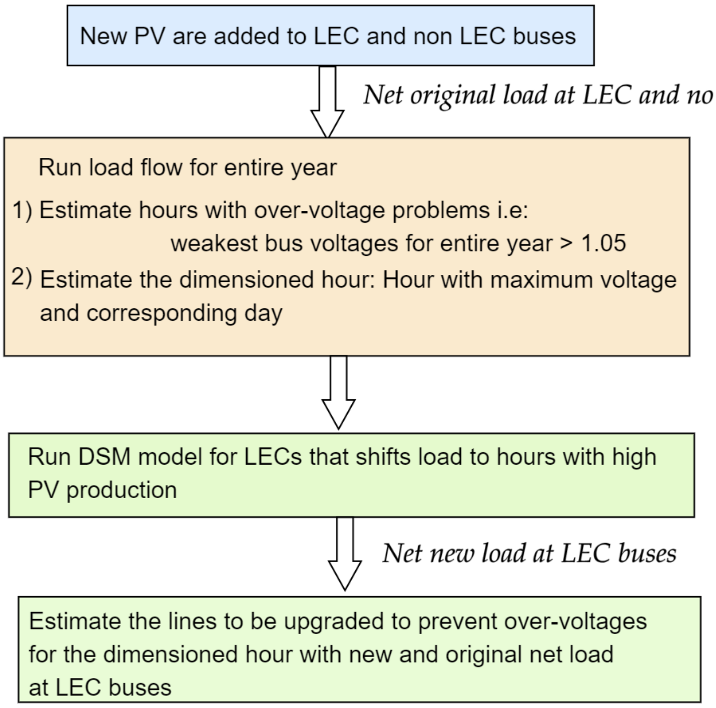

Figure 19: Flowchart of the methodology to handle over-voltages in distribution grid.

Remark: The objective of LEC (DSM strategy explained through Figure 18*) and the explained methodology do not demonstrate direct monetary rewards; however, they will increase self-consumption for LECs during the summer, which in turn reduces their total import from the grid. Therefore, this objective could offer substantial economic benefits to LECs, especially during periods of high load in the summer. Furthermore, this also indirectly benefits the DSO in terms of power line upgrade deferral. The DSO can pass on these benefits as incentives to the LECs, similar to what is seen in Chapter 3 with the undervoltage case. In this chapter, we do not explore the details of the incentives; nonetheless, this problem formulation and objective still represent a highly financially viable strategy for LECs.*

4.3 Case study

Photovoltaic systems (PVs) have been allocated to several buses within our grid model to simulate solar energy contributions. PVs are connected to the following buses: **84, 90, 91, 92, 96, 99, 101**. Additionally, PV installations are also connected to LEC buses. Specifically, **LEC 1** is connected to bus **30**, **LEC 2** to bus **38**, **LEC 3** to bus **65**, **LEC 4** to bus **89**, and **LEC 5** to bus **104**. Each of these PV systems has a capacity of **1 MW** and operates based on a solar profile representative of the Oslo region. For a summer day PV generation profile has been shown in Figure 21.

We used one year load profile and PV production profiles for the buses mentioned earlier, and then we conducted a load flow analysis on the net profile for the entire year. This analysis helped us identify the maximum voltage at the weakest bus, which is the farthest from the main feeder in the distribution grid and determine the specific hour and day when this maximum voltage occurs. Having identified a typical day with maximum voltages, we focused all our analyses on this day.

We studied four cases, two of which are based on the original load where the LEC has flexibility and the other without flexibility. The other two cases involve scaled loads of LEC on a summer day. This scaling was done to simulate a future scenario with a significant increase in electric vehicles, considering the current load data is from 2018. For our theoretical study, we doubled the load to reflect this anticipated future increase in EVs.

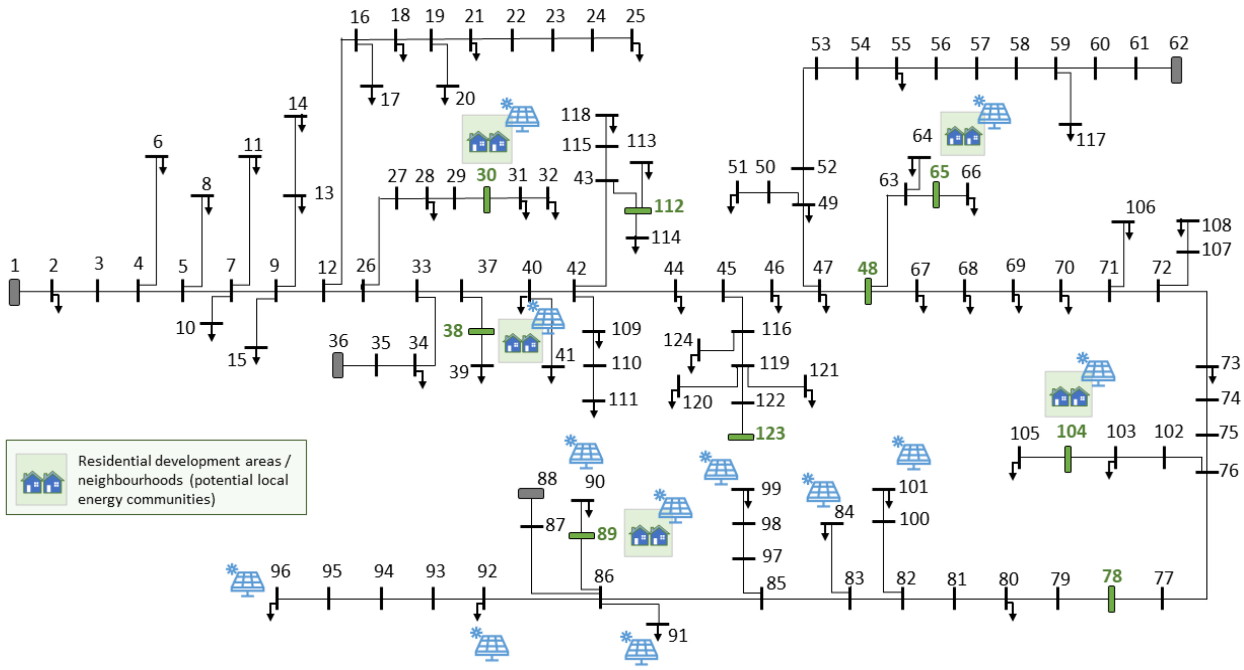

Figure 20: CINELDI MV reference grid with case for PV integration and overvoltage.

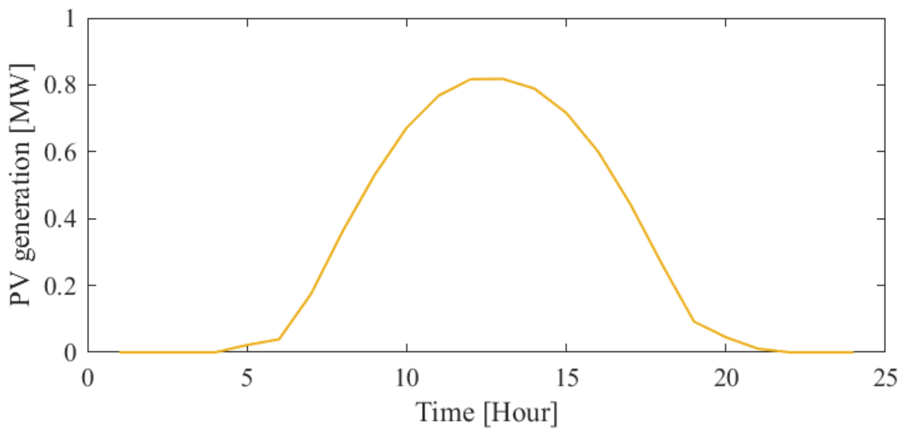

Figure 21: PV generation profile for a summer day (dimensioning day with maximum overvoltage problem).

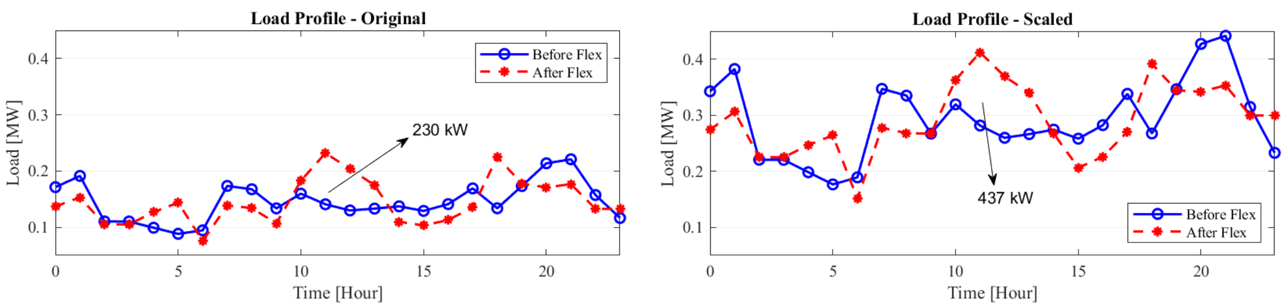

Figure 22: Illustration of how loads from LEC 1 (at Bus 30) are shifted in hours.

In Figure 22 we can see the impact of flexibility activation for LEC where the demand from evening and morning times is being shifted towards the daytime when solar production is the highest. In the unscaled original loads, the total demand for every hour and for the entire day was low so correspondingly the flexibility was also low (considering 20% load is flexible). Therefore, the time-shifting of energy consumption towards daytime was not significant and we see an increase of 230 kW demand at the noon when PV generation was the highest. However, when the load is scaled (twice from original load) flexibility get increased and hence we could see much more significant load shifting towards daytime of 437 kW. From this we can infer that if the loads are less in summer then this objective of increasing self-consumption through time shifting of loads is not fruitful.

The objective of our formulated optimization problem is to increase self-consumption by shifting loads to daytime hours. This approach is designed to deliver the most optimal solution in terms of DSM. From the DSO's perspective, our objective ensures maximum self-consumption, which is particularly critical in the summer when alternative solutions may not be as viable or effective. Thus, our targeted objective is viewed as the optimal approach by the DSO. In the Norwegian context, where electrical loads are low in summer, DSM strategies for overvoltage may not be beneficial.

As the original unscaled loads have low flexibility options, the corresponding improvements in voltages using flexibility are also minor. This is seen in Figure 23 where the decrease in voltage (from original loads no flex to original load flex) is only 0.0026 p.u. When we have scaled the loads then there was an obvious decrease in voltage as seen in red plot of no flex. However, after using the flexibility on the scaled loads, we see a drop in voltages of 0.0052 p.u.

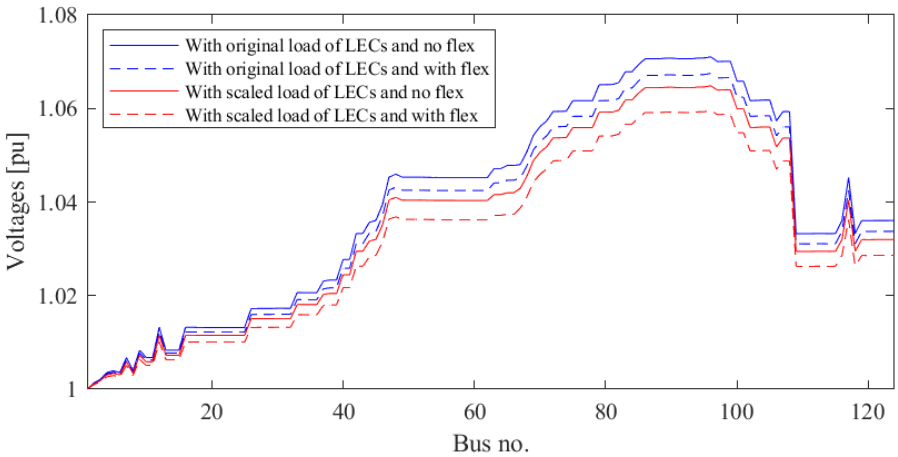

Figure 23: Voltages for dimensioning hour (12th hour).

In the four scenarios previously discussed, the different power line upgrade costs are presented in the Figure 24. It shows that the difference between the original load with no flexibility and the original load with flexibility is 0.41 MNOK. Meanwhile, the difference for the scaled load is 0.76 MNOK. This aligns with our intuitive understanding that flexibility should reduce power line upgrade costs. We observe this in the comparison of original loads and scaled loads, where using flexibility with scaled loads results in almost twice the reduction in power line upgrades compared to the original loads.

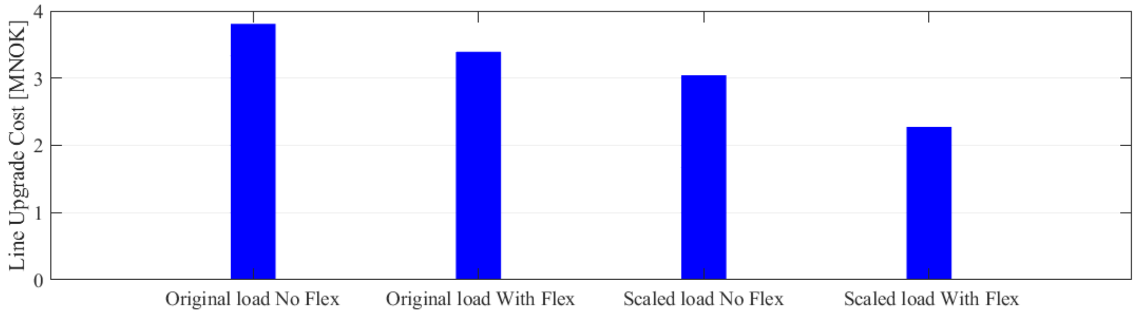

Figure 24: Line upgrade cost with and without flexibility in different load scenarios.

As previously mentioned, an increase in load flexibility within LECs can lead to a reduction in power line upgrade costs. Figure 25 below illustrates the extent of this cost reduction when the LEC's load is doubled on a summer day, resulting in an increased amount of flexible load. We varied the percentage of the flexible load from 0 to 80%. It's observed that the power line upgrade cost fluctuates between 3 MNOK and 1.5 MNOK. If extreme flexibility is available in the distribution grid, it can bring down the cost to almost half.

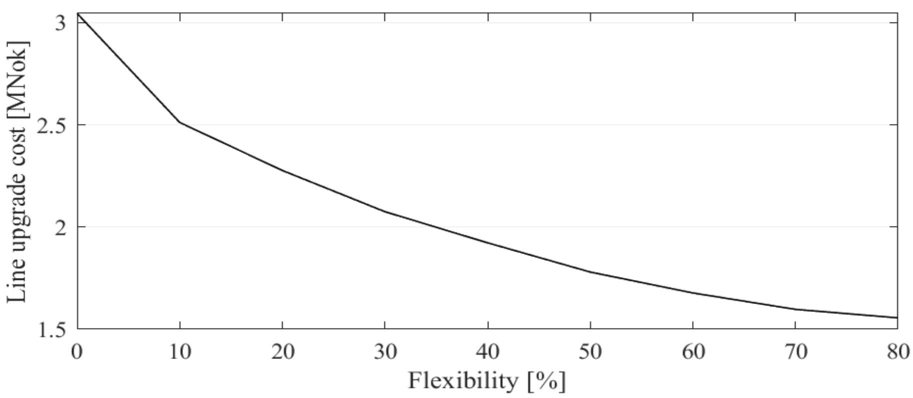

Figure 25: Impact of flexibility increase on powerline upgrade costs.

Table 12: Daily operational cost for LEC 4 (at Bus 89).

	Original load	Original load with flex	Scaled load	Scaled load with flex
Daily operational cost (NOK)	2986	2900	7076	6599
Daily revenue (NOK)	2409	2354	1118	840
Net operational cost (NOK)	577	546	5958	5759
PV exported (MWh)	3.97	3.89	1.84	1.38
PV self-consumption (MWh)	3.19	3.27	5.33	5.79

We are assessing our previous results on the impact of using flexibility on scaled loads from a financial viability perspective (Table 12), focusing on LEC4 at bus 89. When we increase the load, as we did by scaling it twice, the operational cost has increased tenfold. On scaled loads, we observe a significant increase in the customer's cost. Therefore, it's essential for the DSO to implement a proper incentive mechanism to keep customers financially viable and to reduce their financial burden.

5 Conclusion

We have explored grid challenges, including undervoltages, overvoltages with a particular emphasis on how demand-side management strategies from LECs can help in effective voltage regulation. Our investigation was not just limited to technical aspects; it also covered the financial implications of these strategies.
The following points are our key findings:

1. **Operational and Financial Benefits in Local Coordination Scenario**:
The local coordination scenario demonstrated operational benefits such as voltage regulation and peak reduction for the DSO, alongside reduced grid import costs for LECs. Financially, the DSO faces a reduction in revenue due to lower tariffs from LECs, which is not offset by savings in power line upgrades. The difference in present value of line upgrade costs (0.52 MNOK) and revenue reduction (2.62 MNOK) highlights a financial gap in this scenario. Importantly, this analysis did not include the costs LECs might incur to achieve flexibility, which could significantly affect the financial dynamics.

2. **Incentive Distribution and Flexibility in Efficient Market Scenario:**
This scenario underlined the importance of location of LECs in the grid. LECs closer to the weakest bus received higher incentives for reducing voltage issues, as demonstrated by the distribution of cost savings (0.72 MNOK) and specific flexibility requirements. This scenario emphasizes the need for a fair incentive mechanism and planned flexibility management.

3. **Overvoltage Management and Demand-Side Management Strategies:**
Addressing the seasonal mismatch in Norway, where high PV generation in summer contrasts with lower demand, the study highlighted the effectiveness of demand-side management strategies. Particularly for high loads in summer, the integration of LEC flexibility led to a notable reduction in power line upgrade costs from 3 MNOK to 1.5 MNOK. The findings suggest that shifting loads to daytime can increase self-consumption and financial benefits for LECs, but the effectiveness is conditional on the level of load flexibility.

4. **Strategic Implications for Line Upgrades and Voltage Regulation:**
Across the scenarios, the strategic integration of power line upgrades and LEC flexibility emerged as a key approach for enhancing voltage regulation. For instance, the study showed a significant reduction in voltage problems and operational costs when combining power line upgrades with LEC flexibility.