Sustainable Energy, Grids and Networks 35 (2023) 101083

Contents lists available at ScienceDirect

Sustainable Energy, Grids and Networks

journal homepage: www.elsevier.com/locate/segan

Economic assessment of integrating fast-charging stations and energy communities in grid planning

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ARTICLE INFO

Article history:
Received 1 February 2023
Received in revised form 12 April 2023
Accepted 29 May 2023
Available online 12 June 2023

Dataset link: https://doi.org/10.5281/zenodo.7703070

Keywords:
Local energy community
Fast-charging station
Active grid planning
Grid development plan

ABSTRACT

Distribution grid companies and distribution system operators (DSOs) still mostly follow a traditional framework for grid planning. Such frameworks have so far served DSOs well in the economic assessment and cost–benefit analysis of passive measures, such as grid reinforcement. However, the development towards active distribution grids requires DSOs to also be able to assess an extended set of *active* measures. To this aim, this paper extends and implements a general planning framework for active distribution grids that builds upon the well-proven traditional framework. The methodology integrated in the framework includes: (1) decoupled models for (i) operation with active measures and (ii) optimal grid investment, and (2) methods for economic assessment considering active measures from both (i) a DSO cost–benefit analysis perspective and (ii) a willingness-to-pay perspective. In this paper, operational models are integrated for two examples of active measures, namely the use of fast-charging stations (FCS) and local energy communities (LEC). The methodology is demonstrated in a long-term grid planning case study for a realistic Norwegian medium voltage distribution system. For this case, grid planning with FCS as an active measure reduces the present value of grid investment costs by 70% compared with a passive grid planning strategy. The results also demonstrate how the methodology can be used in negotiating the price of active measures between the DSO and distribution system actors such as LEC and FCS operators.

1. Introduction

Within a traditional, passive grid planning framework [1,2], new local energy communities (LECs) and fast-charging stations (FCSs) for electric vehicles (EVs) are seen as new loads that are potential sources of grid problems. These are examples of new types of entities in the distribution system that are owned and operated by other actors than the distribution system operator (DSO). From the perspective of a DSO, each of these entities can be viewed as a single, aggregated load located at the point of common coupling. If uncontrolled, load increase can cause undervoltage problems for both the new and existing loads and can drive the need for costly grid investments. 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 [3]. Norwegian DSOs therefore often use as a planning criterion that the voltage in the medium voltage (MV) distribution grid should exceed a higher limit value, such as 0.95 p.u.

Active distribution grids [1,4] imply more opportunities for grid planners in the form of new *active measures* to supplement traditional (passive) grid investment measures [5]. Active measures are here defined as involving active utilization of resources in the system during operation. That is, the DSO can activate and control the resource directly or indirectly by dynamically modifying its set-points. These resources may be flexibility resources [6] or other resources utilized in active grid operation (active management) [4,7]. In the example illustrated in Fig. 1, the DSO can interact with LEC and FCS operators to utilize these loads as flexibility resources in the operation of the distribution system. However, these opportunities related to active measures also introduce new challenges to grid planners since they need to account for the costs and benefits of these measures in their grid planning studies. For each type of active measure, their operational characteristics need to be represented in the planning studies in a way that strikes a reasonable compromise between accuracy and complexity for planning purposes.

Several investigations have been carried out to study the integration of EV charging stations into the distribution grid expansion planning problem. The authors of [8] propose a mixed integer linear programming (MILP) model to solve the robust multistage joint expansion planning of distribution systems and the allocation of EV charging stations. The authors of [9,10] determine the optimal construction or reinforcement of substations, feeders and EV charging stations, and the placement of

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https://doi.org/10.1016/j.segan.2023.101083

Nomenclature

Parameters

α_{ij}	Auxiliary binary variable denoting the choice of line reinforcement between bus i and j
t_w	Dimensioning hour (with the most severe voltage problems)
$\gamma_n^{\mathrm{su,max}}$, $\gamma_n^{\mathrm{sd,max}}$, $\gamma_n^{\mathrm{nce,max}}$	Percentage of load which is flexible in LEC model
ϕ_i	Power factor angle
c^{lr}	Cost of load reduction
c^{sd}	Cost of load shifting
c_{ij}	Cost per length of a new line between bus i and j
f_{d}	Annual discount rate
L_{ij}	Length of line between bus i and j
n_d	Number of days in representative period
P_i^{lim}	Load demand limit
$P_i^{\mathrm{ref,peak}}$	Baseline peak load demand during the period
$P_{i,t}^{\mathrm{ref}}$	Reference load demand
$p_{i,t}$	Active power load at bus i and hour t
$P_{i,t}^{\mathrm{fcs}}$	Active power consumption of FCS
$q_{i,t}$	Reactive power loads at bus i and hour t
$Q_{i,t}^{\mathrm{fcs}}$	Available reactive power of FCS
r_{flex}	Peak shaving ratio, level of flexibility utilization
r_{ij}	Resistance of the line connecting bus i and j
r_{ij}^{new}	Resistance of the new line connecting bus i and j
S_i^{fcs}	Apparent power rating of FCS
T_{life}	Economic lifetime of the investment
$v_{i_w}^{\mathrm{limit}}$	Voltage limit for the weakest bus
x_{ij}	Reactance of the line connecting bus i and j
x_{ij}^{new}	Reactance of the new line connecting bus i and j
y_{active}	The first year active measures are implemented
y_{end}	Length of the analysis horizon (years)
y_{t}	Length of the planning horizon (years)

Indices and Sets

$\Omega_{\mathrm{inv},y_{\mathrm{t}}}$	Set of reinforced lines for grid development plan at the end of planning horizon.
$\Omega_{\mathrm{lec},y}$	Set of LEC buses in year y
$\Omega_{\mathrm{plan},y_{\mathrm{t}}}$	Set of reinforced lines near the end of the planning horizon, taken from an investment optimization model
$\Omega_{\mathrm{plan},y}$	Set of reinforced lines for each year y from investment optimization model.
$\Omega_{\mathrm{reinf},y}$	Set of lines that is being reinforced for each year y in the planning horizon
d	Index of representative period within the year
i_w	Index of weakest bus
$l(i_w)$	Subset of lines along the path from the main feeder to the weakest bus
n	Bus index for LEC buses
t	Time index (hour)
y	Year index

Variables

$\hat{u}_{i,t_w}$	Voltage at bus i at t_w hour when considering new lines
$\hat{w}_{ij,t_w}$	Auxiliary variable to denote line-wise voltage drop in the grid without line reinforcement
u_{i,t_w}	Voltage at bus i at t_w hour when considering old lines
u_{j,t_w}	Voltage at bus j at t_w hour when considering old lines
$\hat{u}_{j,t_w}$	Voltage at bus j at t_w hour when considering new lines
$P_{i,t}^{\mathrm{net}}$	Net load after flexibility activation
$Q_{i,t}^{\mathrm{net}}$	Reactive power consumption of the LECs
w_{ij,t_w}	Auxiliary variable to denote line-wise voltage drop in the grid with line reinforcement
$E_{i,t}^{\mathrm{sd}}$	Intermediate variable to keep track of the accumulated amount of load shifted downwards
$E_{i,t}^{\mathrm{su}}$	Intermediate variable to keep track of the accumulated amount of load shifted upwards
$P_{i,t}^{\mathrm{lr}}$	Amount of load reduction at each time step
$P_{i,t}^{\mathrm{sd}}$	Amount of load that can be shifted down at each time step
$P_{i,t}^{\mathrm{su}}$	Amount of load that can be shifted up at each time step

distributed generation units. The results focused on investments in the distribution lines and substations to avoid possible overloads related to demand and EV growth. There is no consideration given to the flexibility that can be offered by EV charging stations. In [11–13], the cost–benefit analysis of integrating methods for charging and discharging of active power for EVs is taken into account as prospective measures for the distribution grid multi-year planning problem. In the context of multi-year and long-term grid planning, cost–benefit analysis of a reactive power and active power dispatch strategy from EVs is investigated in [14].

In addition to the flexibility of charging stations, flexibility can also be enabled from new neighbourhoods and residential development areas. One very topical opportunity is to incentivize them to form LECs that aggregate the flexibility potential from shiftable loads, energy storage devices etc. to modify the load profile as seen from the DSO's perspective. A review of energy communities modelling and simulation approaches is presented in [15], and a case study is presented in [16]. In [17], the authors presented a model to determine the joint expansion planning of distributed generation and the distribution grid considering the impact of energy storage systems and price-dependent demand response programmes. Moreover, the authors have formulated and solved the combined investment and operational problem as

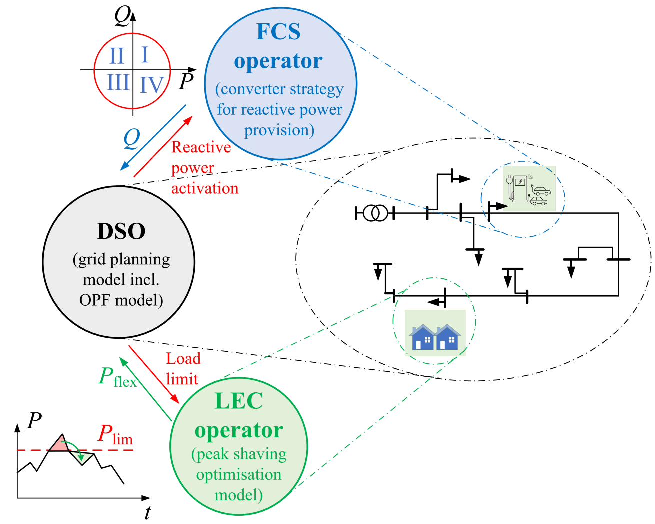


Fig. 1. Schematic of systems and actors (Distribution System Operator, Fast-Charging Station operator, Local Energy Community operator) and their interactions.

a single, large mixed integer optimization model. Due to the large number of continuous variables needed to model steady-state grid performance and the high number of binary variables used to represent the investment in new assets, the optimization problem for long term planning with active measures is extremely complicated. The size of practical distribution grid models may very well render state-of-the art optimization models computationally infeasible.

The authors of [18] formulated bi-level programming as a feasible solution methodology for the generation and distribution expansion planning problem, considering expansion planning in the upper level and decisions connected with the flexibility of the demand in the lower level. Similarly, in [19], the demand response resource is co-optimized with the configuration of lines and energy storage devices to achieve the economic trade-off between the investment cost and the operational cost. With feedback from planning problems, operational problems are resolved at a lower level to decrease daily operational costs. The methodologies described in [18,19] are bi-level detailed operational and investment models, where the upper level problem is constrained by the lower level.

In practice, different actors will have different information on and different levels of control of the distribution system and its subsystems (e.g., LECs and FCSs). Therefore, it is advantageous to decouple the problem into a detailed operational model and an investment model, unless one assumes a centralized decision maker with full information and full control of the entire system. This will help making active distribution grid planning of realistic distribution grids feasible in practice. Along this line, the authors in [20] implemented a bi-level decoupled planning approach. At the lower level, the energy hubs optimization problem is solved, and at the higher level, the expansion of the electricity and gas network is planned. The hub operator is responsible for decisions at the lower level, while the DSO is responsible for decisions at the higher level.

The majority of prior research has examined flexibility from local energy communities and fast-charging stations separately as measures in grid planning. In this paper, we explore high-level representations of two active measures, flexibility service provision from LECs and FCSs, that can be effectively integrated in a general grid planning framework. The aim is to make it possible for DSOs to assess if it is economically rational to implement active measures involving either LECs or FCSs or both.

Existing grid planning practices are to a very limited degree able to account for active measures, such as planning for utilizing flexibility resources [6]. The majority of grid companies lack the resources and knowledge to simultaneously solves the combined grid planning and operational planning optimization problem for actual (real-sized) grid models. The methodology presented in this paper is integrated in a framework for planning of active distribution grids first presented in [5]. An important reason for presenting the methodology within the context of the grid planning framework is to bridge the gap between existing grid planning practices and ideal grid planning methodologies documented in the scientific literature. The framework is based on a traditional planning framework utilized by Norwegian DSOs [2] and is therefore easily recognizable and suitable for incrementally enhancing current practices.

In addition, loosely coupled operational and investment planning models are considered, in contrast to a combined optimization model where models for the operational time horizon are embedded within a model for the long-term planning horizon. In this work, the objective of the operational models of LECs and FCSs is peak reduction and reactive power injection, respectively, which help in regulation of both voltage level and line congestion, and thereby do not cause new grid problems during operation. Consequently, as the operational strategies considered for LECs and FCSs have no adverse impact on the voltages and power flows in the grid, it becomes possible to work on planning and operational models individually.

In summary, the contributions of this work are as follows:

- It presents a methodology that can be used to study the implications of active measures on grid investment and grid development plans. The methodology integrates operational and investment planning models in a way that makes it practicable for DSOs to compare cost-effectiveness of different active measures (here exemplified by LEC and FCS).
- The non-linear reinforcement planning problem is linearized by decoupling planning stage variables from operation stage variables, thereby decreasing the computational complexity of the proposed methods. The methodology's tractability was demonstrated using a reference grid model consisting of 124 buses that is representative of real Norwegian MV grids [21].
- Finally, results from the operational and investment models are used as inputs to methods for economic assessment considering active measures from both (i) a DSO cost–benefit analysis perspective and (ii) a willingness-to-pay perspective. To the authors' knowledge, this is the first work considering economic assessment of active measures or flexibility from both perspectives, which allows a discussion of the business case for different actors (i.e., DSOs and flexibility providers).

The paper is organized in the following way: Section 2 summarizes the general framework for planning of active distribution grids and gives an overview of how the methodology proposed in this paper is integrated in this framework. Section 3 describes the proposed decoupled mathematical models for the investment and operational problems. Section 4 presents the mathematical formulation of the economic assessment. Section 5 presents the case study, with the results of the economic assessment presented in Section 6. Finally, the paper is concluded in Section 7.

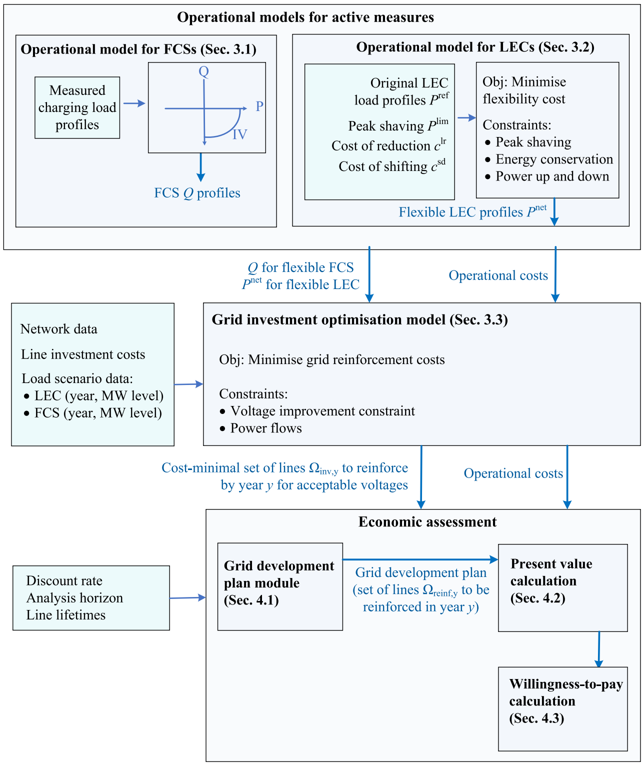


Fig. 2. The proposed DSO grid planning model that is an implementation of the general framework for active distribution grid planning [5] and that integrates the decoupled operational and investment models.

2. Framework implementation for planning of active distribution grids

This section briefly summarize the implementation steps of the framework [5] and the models and methods incorporated in each step. The starting point of the grid planning framework is some identified challenge or need in the grid - in the present grid or expected in the future - that triggers the grid planning process. The methodology proposed in this paper is targeting grid planning needs due to the integration of LECs and FCSs for EVs in MV distribution grids.

This paper focuses on modelling the long-term development of load demand in the system over the 10 year planning horizon. A set of scenarios describe the DSO's expectation for when new load points (potential LECs and FCSs) are integrated into the system and their annual peak load demand. Examples are given as part of the case study in Section 5. The variability over the year is modelled by individual load time series with hourly resolution for all load points. For the modelling of system operation described below, a reduced set of representative periods is selected.

In general, a relevant active measure is to enable the potential flexibility of the loads that are triggering the grid planning process. In this paper, we therefore focus on two active measures: Utilizing flexibility from LECs (for peak shaving) and FCSs (reactive power provision). Fig. 2 illustrates how operational models for these two active measures are integrated in the framework, and the models are described in more detail in Sections 3.1 and 3.2, respectively. These exemplary operational models are based in part on existing models in the literature, but their integration and application in this paper is novel and necessary to demonstrate the methodology for economic assessment of active measures.

The operational models will be loosely coupled to a novel investment model, presented in detail in Section 3, that suggests the necessary grid reinforcements considering different options for the use (or not) of active measures. Investment needs for different years are used to construct grid development plans (Section 4.1) that specify when in the planning horizon the different measures (passive or active) are applied.

Finally, a cost–benefit analysis model is used to (1) calculate the present value of the DSO's investment and operational costs the grid development plans entail (Section 4.2) and (2) estimate the DSO's willingness to pay for active measures to reduce or defer grid investments (Section 4.3). In the traditional grid planning framework, present value calculations should ideally consider the following socio-economic cost components: investment costs, operational and maintenance costs, costs of grid losses, costs of energy not supplied, and congestion costs [2,5]. In the framework for active distribution grid planning, the cost of utilizing flexibility as an active measure enters as a new operational cost. This paper therefore focuses on this operational cost in addition to grid investment costs.

3. Decoupled operational and investment models for grid planning

This section presents the operational and investment models illustrated in the two topmost blocks of Fig. 2: The operational model for FCSs and LECs are presented in Sections 3.1 and 3.2, respectively, while the investment model is presented in 3.3.

The operational models have to be able to capture the operational benefits of active measures, while the planning model needs to capture grid investment needs with an acceptable trade-off between computational efficiency and accuracy. In this paper, we propose a decoupled approach, where the model for the decision-making of the DSO assumes information about the distribution system but no detailed information about the LEC and FCS sub-systems. This corresponds to a decentralized and partially grid-unaware approach according to the classification in [22], in the sense that the operational models, which are high-level representations of the LEC and FCS actors' decision-making, assume no information about the distribution system. These subsystems, actors, and their interactions were illustrated in Fig. 1.

3.1. Operational model for FCS as an active measure

It is assumed that there are bidirectional off-board chargers installed at the FCS. The active and reactive power control of the charger is related to the capability curve of the converter. Bidirectional chargers can operate in any of the four quadrants, as shown in Fig. 1.

The goal of an FCS is to provide to as much active power as possible to charging EVs. However, reactive power can be controlled without interfering with EV charging [23]. In the previous studies [23,24], a DSO operational model was proposed for calculating the optimal reactive power Q for minimizing voltage deviations. However, in this work, a simpler representation of this active measure can be used instead of an optimization model that assumes information from both the FCS operator and the DSO for the operational planning. For long-term planning purposes, it will be assumed that the maximum reactive power injection ($Q_{i,t}^{\mathrm{fcs}}$) from FCS converters is utilized to attain acceptable voltages for the hours t where this is needed:

$$Q_{i,t}^{\mathrm{fcs}} = \sqrt{(S_i^{\mathrm{fcs}})^2 - (P_{i,t}^{\mathrm{fcs}})^2} \tag{1}$$

The reactive power available $Q_{i,t}^{\mathrm{fcs}}$ for voltage support from FCSs is limited by the apparent power rating of the FCSs S_i^{fcs}, as well as the power consumption of the EVs, $P_{i,t}^{\mathrm{fcs}}$. Since the majority of the lines in the longest lateral of the grid under study have an R/X ratio of less than 5, the maximum reactive injection of FCS converters may be sufficient for voltage improvement. This means that FCSs indirectly contribute to grid support without any signals from DSOs unlike in [23,24]. In this work, it is assumed that information about expected aggregated charging load profiles and the aggregated FCS converter capability curve is provided to the DSO's investment model. Additionally, the reactive power provision is assumed to not incur any costs for the DSO, but the value of the FCS flexibility is quantified in Section 4.3.

3.2. Operational model for LECs as an active measure

The high-level representation of LEC flexibility chosen for this paper is adapted from the generic model of aggregated demand flexibility proposed in [25–27]. Here, $P_{i,t}^{\mathrm{ref}}$ is the reference load demand and the variables $P_{i,t}^{\mathrm{sd}}$ and $P_{i,t}^{\mathrm{su}}$ represent upwards and downwards load shifting, respectively. The variable $P_{i,t}^{\mathrm{lr}}$ represents load reduction that is not recovered by a corresponding load increase. The net LEC load after flexibility activation is defined as

$$P_{i,t}^{\mathrm{net}} = P_{i,t}^{\mathrm{ref}} + P_{i,t}^{\mathrm{su}} - P_{i,t}^{\mathrm{sd}} - P_{i,t}^{\mathrm{lr}} \tag{2}$$

The objective of the LEC operational model is to minimize the socio-economic costs due to flexibility activation:

$$\min \sum_{t\in\Omega_T} \sum_{i\in\Omega_{lec,y}} \left(c^{\mathrm{sd}} P_{i,t}^{\mathrm{sd}} + c^{\mathrm{lr}} P_{i,t}^{\mathrm{lr}}\right) \tag{3}$$

Here, c^{sd} is the cost of load shifting and c^{lr} is the cost of load reduction. (How the costs due to flexibility activation can be interpreted from the perspectives of the LEC operator and the DSO is further discussed in Section 6.3.) Since load reduction is not recovered by a corresponding load increase, c^{lr} is typically much higher than c^{sd}. Note that the objective function only includes a term for downward load shifting; a separate term for the upward demand shifting is redundant because the total amounts of downward and upward demand shifting over Ω_T will be identical due to the constraints introduced below.

The flexibility mechanism assumed for LECs in this paper is a decentralized scheme where the DSO gives the LEC operator a load demand limit P_i^{lim} that the aggregated net power consumption should not exceed during a given period:

$$P_{i,t}^{\mathrm{net}} \le P_i^{\mathrm{lim}} \tag{4}$$

This mechanism resembles the operating envelope concept [22] and is a customer-oriented rather than system-oriented approach that does not assume the LEC operator to have any information about the grid model. It is then the responsibility of the LEC operator to coordinate the loads within the community, and the community is compensated by the amount of load that is shifted and/or reduced compared to the baseline load profile. In the high-level representation used in this paper, the load demand limit in (4) that is received by the LEC operator from the DSO is expressed through the relationship

$$P_i^{\mathrm{lim}} = (1 - r_{\mathrm{flex}}) P_i^{\mathrm{ref,peak}} \tag{5}$$

Here, $P_i^{\mathrm{ref,peak}}$ is the baseline peak load demand during the period and $r_{\mathrm{flex}} \in [0, 1]$ is a peak shaving ratio that is introduced as a convenient single-parameter measure of the DSO's utilization level of flexibility from the LECs. It is assumed that both the LEC operator and the DSO have information on the baseline day-ahead load forecast $P_{i,t}^{\mathrm{ref}}$. As an alternative to the hard limit P_i^{lim} considered in this operational model, one could also represent other mechanisms for LEC flexibility activation, such as models for capacity-based grid tariffs combined with local markets, as e.g. proposed in [28]. Incorporating such models in the long term grid planning framework in Fig. 2 will be considered in future work.

Load shifting implies that the energy consumption over the time horizon is conserved, so that the total amount of load shifted upwards has to be equal to the total amount of load shifted downward at the end of the operational time horizon. This is captured by Eqs. (5a) to (5c), which introduces variables $E_{i,t}^{\mathrm{sd}}$ and down $E_{i,t}^{\mathrm{su}}$ for keeping track of the accumulated amount of load shifted downwards and upwards, respectively, until time step t.

$$E_{i,T}^{\mathrm{su}} = E_{i,T}^{\mathrm{sd}} \forall n \in \mathcal{N} \tag{5a}$$

$$E_{i,t}^{\mathrm{su}} - E_{i,(t-1)}^{\mathrm{su}} = \Delta T \cdot P_{i,t}^{\mathrm{su}} \quad \forall \;\; i \in \mathcal{N}, \forall t \in \{\mathcal{T} \setminus \{1\}\} \tag{5b}$$

$$E_{i,t}^{\mathrm{sd}} - E_{i,(t-1)}^{\mathrm{sd}} = \Delta T \cdot P_{i,t}^{\mathrm{sd}} \quad \forall n \in \mathcal{N}, \forall t \in \{\mathcal{T} \setminus \{1\}\} \tag{5c}$$

Moreover, the amount of load that can be shifted down and up at each time step is also limited to a certain share of the reference load demand using Eqs. (6a), (6b).

$$P_{i,t}^{\mathrm{su}} \le \gamma_n^{\mathrm{su,max}} P_{i,t}^{\mathrm{ref}} \forall n \in \mathcal{N}, \quad \forall t \in \mathcal{T} \tag{6a}$$

$$P_{i,t}^{\mathrm{sd}} \le \gamma_n^{\mathrm{sd,max}} P_{i,t}^{\mathrm{ref}} \quad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{6b}$$

Similarly, the amount of load reduction at each time step is limited to a share of the reference demand:

$$0 \le P_{i,t}^{\mathrm{lr}} \le \gamma_n^{\mathrm{nce,max}} P_{i,t}^{\mathrm{ref}} \qquad \forall n \in \mathcal{N}, \forall t \in \mathcal{T} \tag{7}$$

Reactive power consumption $Q_{i,t}^{\mathrm{net}}$ of the LECs is assumed to vary proportionally with the active power, making the power factor angle $\phi_{i,t}$ constant:

$$Q_{i,t}^{\mathrm{net}} = P_{i,t}^{\mathrm{net}} \tan\phi_i \tag{8}$$

3.3. Investment model

This section presents the DSO investment model. It is designed for a distribution system that is primarily a voltage-constrained system in the sense that, as load demand increases, under-voltage issues for buses manifest in the grid before overloading issues for lines. As mentioned in earlier sections, residential load points and fast-charging stations (FCSs) will be added to the grid during the next few years, resulting in unacceptable low bus voltages during specific hours of system operation. This motivates the proposed "voltage-oriented" investment model.

The objective of the investment model is least-cost expansion of the distribution system under a strict voltage constraint at the weakest bus. That is, by limiting the voltage drop at any particular bus to a specified value, we reduce the required cost of line upgrades under predicted FCS power consumption. It is assumed that power lines will be upgraded such that grid impedance reduces, thereby inducing reduced voltage drop at weak buses. The investment cost for line upgrade can be minimized as follows,

$$\min \quad C'_y = \sum_{ij \quad \mathrm{lines}} (1 - \alpha_{ij}) c_{ij} L_{ij} \tag{9}$$

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

To ascertain the line upgrade between any two buses, we first compute the voltage drop with the existing line in the hour t_w that is dimensioning for the system. The dimensioning hour is defined as the hour with the weakest bus voltage value. The active and reactive power flow in the grid can be calculated using *LinDistFlow* [29] equations as follows,

$$P_{ij,t_w} = \sum_{k:j\to k} P_{jk,t_w} - p_{i,t_w} - P^{\text{fcs}}_{i,t_w} - P^{\text{net}}_{i,t_w} \quad (10a)$$

$$Q_{ij,t_w} = \sum_{k:j\to k} Q_{jk,t_w} - q_{i,t_w} - Q^{\text{fcs}}_{i,t_w} - Q^{\text{net}}_{i,t_w} \quad (10b)$$

where, P_{ij,t_w} and Q_{ij,t_w} are the active and reactive power flows in line (i to j). Active and reactive power loads at bus i are p_{i,t_w} and q_{i,t_w}, respectively. The impedance of the line connecting bus i and j is $r_{ij} + jx_{ij}$.

Moreover, the voltage drop between two subsequent buses i and j, can be computed for old and new lines using Eqs. (11a) and (11b) respectively,

$$u_{i,t_w} - u_{j,t_w} = 2(r_{ij}P_{ij,t_w} + x_{ij}Q_{ij,t_w}) \;\; \forall\, ij \;\; \text{lines} \quad (11a)$$

$$\hat{u}_{i,t_w} - \hat{u}_{j,t_w} = 2(r^{new}_{ij}P_{ij,t_w} + x^{new}_{ij}Q_{ij,t_w}) \;\; \forall\, ij \;\; \text{lines} \quad (11b)$$

Using Eqs. (11a)–(11b), the voltage drops to the weakest bus (i_w) can be constrained to be less than a specified value $v^{\text{limit}}_{i_w}$, as mentioned in (12).

$$\sum_{ij\in l(i_w)} \alpha_{ij}(u_{i,t_w} - u_{j,t_w}) + \sum_{ij\in l(i_w)} (1-\alpha_{ij})(\hat{u}_{i,t_w} - \hat{u}_{j,t_w}) \le 1 - v^{\text{limit}}_{i_w} \quad (12)$$

where, the first and second term in Eq. (12) denote the cumulative voltage drop due to old and upgraded lines respectively. The use of the binary variable α_{ij} in the algorithm would only allow line-upgrade between bus i and j if the old line is removed. Thus, the new lines cannot be placed in parallel to the old ones, keeping the distribution grid topology purely radial. In addition, $l(i_w)$ is the subset of lines along the path from the main feeder (bus 1) to the weakest bus. This subset will assist the model in eliminating all unnecessary lines that should not be considered if voltage problems exist at some specific buses.

It may be noted that Eq. (12) is a mixed-integer nonlinear (MINLP) non-convex constraint, in part due to having a product of u with the integer variable α. This optimization model is challenging to solve with most commercial and open-source solvers, as shown in Table 1.

To reframe the corresponding MINLP as a linear (i.e., MILP) problem, we create auxiliary variables w_{ij,t_w} and $\hat{w}_{ij,t_w}$ to denote the line-wise voltage drop in the grid, with and without line reinforcement, as follows,

$$u_{i,t_w} - u_{j,t_w} = w_{ij,t_w} \;\; \forall\, ij \;\; \text{lines} \quad (13a)$$

$$\hat{u}_{i,t_w} - \hat{u}_{j,t_w} = \hat{w}_{ij,t_w} \;\; \forall\, ij \;\; \text{lines} \quad (13b)$$

If the values of w_{ij,t_w} and $\hat{w}_{ij,t_w}$ are found a priori, in particular using distribution level power flow as in forward/backward sweep, Eq. (12) can be reformulated as follows,

$$\sum_{ij\in l(i_w)} \alpha_{ij}\hat{w}_{ij,t_w} + \sum_{ij\in l(i_w)} (1-\alpha_{ij})w_{ij,t_w} \le 1 - v^{\text{limit}}_{i_w} \quad (14)$$

which simplifies the non-linear optimization programme to linear, thereby making the expansion planning more tractable. In addition, a linear optimization model aids in the solution of investment problems even for grid models larger than the one under consideration and can be solved using all the solvers listed in Table 1.

By controlling the voltage drop at buses in the system, the DSO will be able to set voltage limitation for the entire system. Thus, for any pre-chosen value of acceptable $v^{\text{limit}}_{i_w}$, the objective Eq. (9) minimizes the cost of line upgrades while assuring that the voltage drop will be limited by Eq. (14).

Algorithm 1: Grid investment planning problem considering active measures

Input: Load data for representative periods, grid data for old lines and new lines, y_t
1) Identify the dimensioning hour t_w using power flow calculations
while $y < y_t$ **do**
- 2) Run the power flow with old lines and new lines and store w_{ij,t_w} and $\hat{w}_{ij,t_w}$ as in Eqs. (13a, 13b)
- 3) Run the investment optimization model (Eq. 9 and Eq. 14)
- 4) **if *Active measure with LECs:* then**
  - a): Run a 24-hour operational flexibility cost minimization model from LECs (Eqs 2-8)
  - b): Update the load profiles of LECs with the profiles obtained from operational model ($P^{\text{net}}_{i,t}$, $Q^{\text{net}}_{i,t}$)
  - c): Go to steps 2 and 3
- **end**
- 5) **if *Active measure with FCSs:* then**
  - a): Calculate the available reactive power of FCSs $-Q^{\text{fcs}}_{i,t}$ using Eq (1)
  - b): Go to steps 2 and 3
- **end**
- $y \leftarrow y + 1$

end

3.4. Integration of operational and investment planning models

Algorithm 1 explains the steps of the method for solving the grid investment planning problem when active measures are considered. Initially, the forward/reverse sweep power flow is utilized to identify the hour during the representative periods with the most critical voltage problems (t_w) caused by FCS and LEC loads. For this dimensioning hour, the investment model is used to calculate the lines that must be upgraded to increase the voltage magnitude in the grid voltage in the case of passive measures [Steps 2 and 3 in Algorithm 1]. In case of active measure from LECs, the 24-hour operational flexibility cost minimization model for LECs is run for the day containing the dimensioning hour. The reference load profiles for LECs without flexibility activation are inputs to the operational model, and adjusted load profiles due to flexibility activation are obtained as outputs. The modified loads for LEC buses for hour t_w are utilized first in running power flow, and then the outputs of power flow, i.e., w_{ij,t_w} and $\hat{w}_{ij,t_w}$, are used in the investment model. Similarly, when active measure from FCSs is included in the grid planning, the updated reactive power for the dimensioning hour is utilized in steps 2 and 3 as mentioned in Algorithm 1.

4. Economic assessment for active distribution grid planning

The investment model presented in Section 3.3 gives as output the optimal (least-cost) grid investments for ensuring acceptable voltage limits for a given set of years and a given strategy for the use of active measures. This section presents methods for economic assessment based on these grid investment costs: Section 4.2 presents a method for cost–benefit analysis from the DSO's perspective based on present value calculations. In Section 4.3, a valuation method for active measures from a complementary willingness-to-pay perspective is presented. First, Section 4.1 describes how the grid development plans are generated to define which investments are made in which year.

Table 1
Tractability of the original (MINLP) optimization model and the linearized optimization model for different solvers. The "Solution" columns indicates whether a solution is guaranteed for the optimization model using the given solver.

Solver type	Solver	Platform	Solution (Non convex-MINLP)	Solution (linearized)
Commercial	CPLEX	Pyomo (Python)	×	✓
Commercial	Gurobi (older version)	Pyomo (Python)	×	✓
Commercial	Gurobi (9.0 and above)	Pyomo (Python)	✓	✓
Open source	Bonmin	Pyomo (Python)	×	✓
Open source	Couenne	Pyomo (Python)	×	✓
Open source	GLPK	Pyomo (Python)	×	✓
Open source	Bmibnb	Yalmip (MATLAB)	✓	✓

4.1. Generation of grid development plans

Grid development plans are generated based on the investment model outputs: The cost-minimal set of reinforced lines $\Omega_{\text{inv},y}$ that are needed to ensure acceptable voltage quality for each year $y \leq y_{\text{t}}$, together with the associated investment costs C'_y that are required.

A grid development plan is defined by the set of lines $\Omega_{\text{reinf},y}$ that is being reinforced for each y in the planning horizon. It describes how the system transitions from the existing grid at $y = 0$ to a "target grid" at the end of the planning horizon $y = y_{\text{t}}$, via potential intermediate system solutions. (A concrete example of a grid development plan is illustrated in Section 6.1 as part of the case study.) The generation of grid development plans starts by taking $\Omega_{\text{inv},y_{\text{t}}}$ from the investment model as the "target grid" and then moving backwards through the planning horizon towards $y = 0$. Let $\Omega_{\text{plan},y}$ be the set of reinforced lines up to and including year y. Then, $\Omega_{\text{plan},\, y_{\text{t}}} = \Omega_{\text{inv},\, y_{\text{t}}}$ describes the target grid, and $\Omega_{\text{plan},\, 0} = \emptyset$ describes the existing grid, and $\Omega_{\text{plan},y}$ for the intermediate years describe intermediate system solutions. For each year $y < y_{\text{t}}$, as one moves backwards through the planning horizon, a subset of lines $\Omega_{\text{reinf},\, y_{\text{t}}} \subset \Omega_{\text{plan},y}$ is removed from $\Omega_{\text{plan},y}$ so that $\Omega_{\text{plan},\, y-1} = \Omega_{\text{plan},y} \setminus \Omega_{\text{reinf},y}$. This is the set of lines that is newly reinforced from year $y-1$ to year y. (To use the example illustrated in Section 6.1: If the target grid is $\Omega_{\text{plan},9} = \{5-7,\ 9-12\}$ and line 5–7 is reinforced from year 8 to year 9, then $\Omega_{\text{reinf},9} = \{5-7\}$ and $\Omega_{\text{plan},8} = \{9-12\}$ describes the system solution in year 8. If no lines are reinforced from year 7 to year 8, then $\Omega_{\text{reinf},8} = \emptyset$, and $\Omega_{\text{plan},7} = \{9-12\}$. Note that in general, the system solutions can also include active measures, but for simplicity we in this section only include the grid reinforcement measures in the sets $\Omega_{\text{plan},y}$.) The set of lines $\Omega_{\text{reinf},y}$ newly reinforced each year is determined by minimizing the difference between the cost of reinforced lines up to year y, according to the grid development plan, and the minimal required investment costs C'_y according to the investment model:

$$\min(C'_y - \sum_{ij \in \Omega_{\text{plan},y}} c_{ij} L_{ij}). \tag{15}$$

This procedure is then repeated for year $y \leftarrow y-1$ until reaching the beginning of the planning horizon.

The total cost of investments made in year y according to the grid development plan will be denoted

$$C_y = \sum_{ij \in \Omega_{\text{reinf},y}} c_{ij} L_{ij} = \sum_k C_{k,y}, \tag{16}$$

where k is used to index investments within the same year. The values of $C_{k,y}$ will be used further in the economic assessment methodology.

4.2. Present value calculation

Assessment of grid development plans involves calculating the present value (referred to year $y = 0$) of investment costs and operational costs incurred in future years $y > 0$. The basic concepts of the present value calculations are illustrated in Fig. 3.

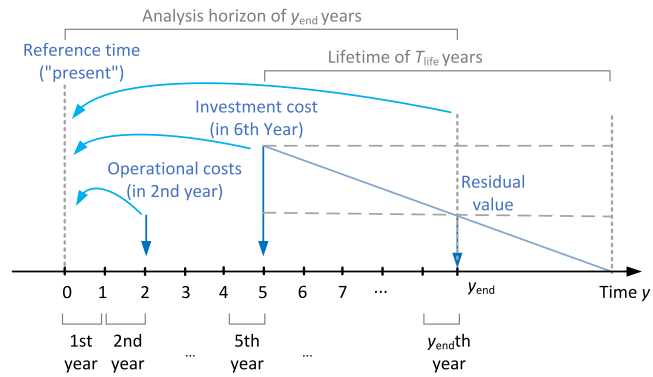


Fig. 3. Present value calculation.

The present value of the operational costs due to load shifting and load reduction (flexibility activation) from LECs is calculated according to

$$\text{PV}_{\text{flex},y} = \frac{\sum_d n_d \sum_{i \in \Omega_{lec,y}} \left(c^{\text{sd}} E^{\text{sd}}_{d,i,T} + c^{\text{lr}} E^{\text{lr}}_{d,i,T}\right)}{(1+f_{\text{d}})^y}, \tag{17}$$

where f_{d} is the annual discount rate. The sum goes over a set of representative periods indexed by d that each represent n_d days of the full year. The calculation of flexibility activation costs for each of the representative periods is explained in more detail in Section 3.2. In the example in Fig. 3, it is illustrated how the present value of these operational costs incurred during the second year are discounted back to the reference time $y = 0$.

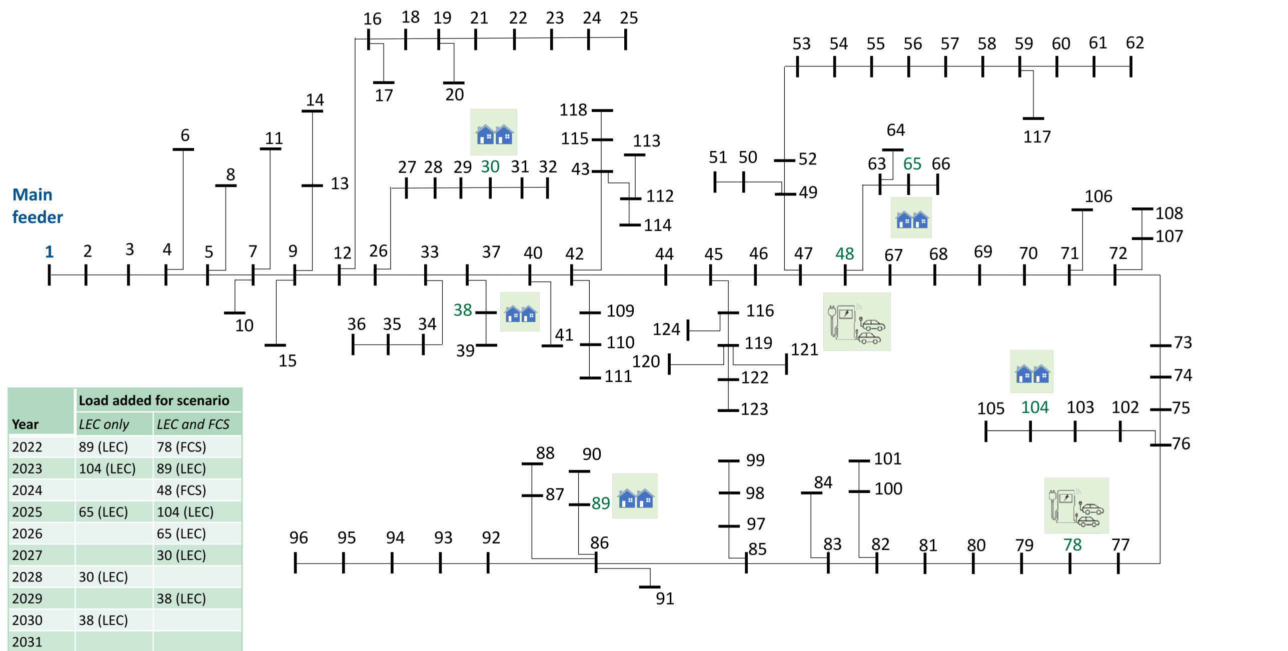
The present value of an investment cost $C_{k,y}$ in year y, corrected for the residual value of the investment left at the end of the analysis horizon, is calculated according to

$$\text{PV}_{\text{inv},k,y} = \frac{C_{k,y}}{(1+f_{\text{d}})^y} - \frac{C_{k,y}\left[1 - (y_{\text{end}} - y)/T_{\text{life}}\right]}{(1+f_{\text{d}})^{y_{\text{end}}}}. \tag{18}$$

Here, the residual value is calculated by linear depreciation, where T_{life} is the economic lifetime of the investment, and y_{end} is the time at the end of the analysis horizon. In the example in Fig. 3, an investment is made at $y = 5$ with a lifetime that exceeds the analysis horizon. The figure illustrates how the present value of the investment therefore needs to be corrected by also discounting the residual value left at the end of the analysis horizon.

The total present value for the grid development plan is found through

$$\text{PV} = \sum_{y=1}^{y_{\text{end}}} \left(\sum_k \text{PV}_{\text{inv},k,y} + \text{PV}_{\text{flex},y} \right). \tag{19}$$



Year	Load added for scenario LEC only	Load added for scenario LEC and FCS
2022	89 (LEC)	78 (FCS)
2023	104 (LEC)	89 (LEC)
2024		48 (FCS)
2025	65 (LEC)	104 (LEC)
2026		65 (LEC)
2027		30 (LEC)
2028	30 (LEC)	
2029		38 (LEC)
2030	38 (LEC)	
2031		

Fig. 4. Reference system representative for a Norwegian radial, MV distribution systems (the CINELDI MV reference system) [21], including two scenarios for when and where new loads are added to the system.

4.3. Valuation of active measures

The approach to economic assessment in the previous subsection was to estimate the DSO's costs and benefits of active measures by assuming the unit cost (in NOK/MWh) of load shifting compensation as an input parameter. An alternative approach is to estimate the DSO's willingness to pay for the flexibility as the competitive or break-even unit cost of using active measures [30,31]:

$$\mathrm{PV}_{\mathrm{sd}} + \Delta\mathrm{PV}_{\mathrm{op}} + \mathrm{PV}_{\mathrm{inv,active}} = \mathrm{PV}_{\mathrm{inv,passive}} \tag{20}$$

Solving the equation gives the competitive unit cost of load shifting (flexibility):

$$c^{\mathrm{sd}} = \frac{\left(\mathrm{PV}_{\mathrm{inv,passive}} - \mathrm{PV}_{\mathrm{inv,active}} - \Delta\mathrm{PV}_{\mathrm{op}}\right)}{\sum_{y=1}^{y_{end}}(1+f_{\mathrm{d}})^{-y}\sum_{d} n_{d}\sum_{i\in\Omega_{lec,y}} E^{\mathrm{sd}}_{d,T,y}} \tag{21}$$

For generality, $\Delta\mathrm{PV}_{\mathrm{op}}$ is introduced for the total present value of other operational costs than the load shifting cost, and it is assumed that the dependence of $\Delta\mathrm{PV}_{\mathrm{op}}$ on c^{sd} can be neglected. This equation is valid also for other mechanisms for demand flexibility activation than the specific mechanism considered in this paper.

Active measures can also be valuated as the willingness to pay for operation of the active measure per year it is in operation. We denote this valuation metric $C^{op,a}$, and the first year it would be incurred is denoted y_{active}.

$$C^{op,a} = \frac{\left(\mathrm{PV}_{\mathrm{inv,passive}} - \mathrm{PV}_{\mathrm{inv,active}} - \Delta\mathrm{PV}_{\mathrm{op}}\right)}{\sum_{y=y_{\mathrm{active}}}^{y_{end}}(1+f_{\mathrm{d}})^{-y}} \tag{22}$$

This can be used to calculate the competitive annual cost of FCS reactive power provision in such a way that it can be compared with the annual cost of LEC flexibility activation.

5. Case study description

5.1. Reference system

We consider a long-term power system planning case for a distribution system shown in Fig. 4: 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. In this paper all loads are scaled by a factor 1/1.4, and the annual peak load demand in this base system is thus 5.231/1.4 = 3.736 MW. The full grid and load data set is available at [32] and described in detail in [21].

Table 2
Planning parameters.

Parameter	Value
y_{t} (years)	10
y_{end} (years)	20
T_{life} (years)	40
r	4%
$v^{\mathrm{limit}}_{i_w}$ (pu)	0.95

5.2. Technical and economic data for planning measures

The operational model and investment model require cost data assumptions for grid reinforcement (passive measures) and flexibility activation (active measures). For simplicity, it is assumed in this case study that grid reinforcement always entails replacing existing lines with new underground cables. Typical cable installation costs, including excavation work, are obtained from [32]. Other planning parameters are summarized in Table 2, and Table 3 summarizes parameter values used in this study for the LEC operational model.

For flexibility activation from residential LECs, an estimated average load shifting cost is chosen based on other publications and recent Norwegian flexibility market price data, and the assumption that average prices for residential LECs over the 10-year planning horizon may be lower than historic prices. The load shifting limits $\gamma^{\mathrm{sd,max}}$ and $\gamma^{\mathrm{su,max}}$ are based on the values

Table 3
LEC flexibility parameters.

Parameter	Value	Parameter	Value (NOK/MWh)
$\gamma^{\mathrm{sd,max}}$ and $\gamma^{\mathrm{su,max}}$	0.2	c^{sd}	1000
$\gamma^{\mathrm{lr,max}}$	1	c^{lr}	10 000
n_1	20		

Table 4
Cases for different levels of flexibility utilization from LECs.

Peak shaving ratio r_{flex}	P_i^{lim} values for five LECs (MW)
0.05	[0.78, 0.54, 0.79, 0.74, 0.83]
0.1	[0.74, 0.51, 0.75, 0.7, 0.78]
0.15	[0.66, 0.45, 0.67, 0.62, 0.70]

found in [27] but are for simplicity approximated to be equal for downward and upward load shifting. The cost of load reduction c^{sd} is chosen to be comparable to, but somewhat lower than, the cost of energy not supplied for the residential sector in Norway.

5.3. Long-term load development scenarios

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. To demonstrate the methodology for considering implications of LECs and FCSs as active measures in grid planning, this case study considers the two scenarios [21]. The first scenario is selected to isolate and study in detail the implications of one type of active measure (LECs), while the second is designed to study the combination and comparison of two active measures (LECs and FCSs). Each LEC is assumed to have an annual peak load value of 0.88 MW, and each FCS is assumed to have an installed capacity of 2 MW. An overview of when and where these new loads are added to the system is shown in Fig. 4.

- *LEC only*: Five new residential development areas that are either proposed, planned or under construction.
- *LEC and FCS*: Five new residential development areas that are either proposed, planned or under construction, and two new fast-charging stations.

These scenarios are designed to trigger enough grid investment needs to make the methodology relevant, and there are up to five LECs but only two FCSs because the load demand of FCSs typically is larger than that of residential LECs supplied through a single distribution substation.

5.4. Load profiles for operational models

To keep the case study simple and allow for a transparent illustration of key principles, only two representative periods are considered: One period that represents dimensioning loading conditions for the system, and one period representing the rest of the year. The same representative periods are assumed for all years in the planning horizon. The value $n_1 = 20$ is chosen as the base case value, subject to a sensitivity analysis in Section 6.1. This means that it is estimated that period 1 covers 20 days of the year, and the day with the highest load demand value for the sum of the existing loads in the grid is selected to represent this period of the year. The corresponding baseline load profiles are shown in Fig. 5(a) for the new residential loads that constitute the five LECs [21] and in Fig. 5(b) for the new FCSs loads. It is assumed that for period 2, which covers $n_2 = 365 - n_1 = 345$ days of the year, the load demand is so low that flexibility activation will not be needed to maintain acceptable voltage quality.

5.5. Active measures

As discussed in earlier sections, the two active measures in the case study are flexibility from LECs based on P_i^{lim} and reactive power provision from FCS. The specifics of each measure, in addition to the baseline profiles, have been discussed in this subsection. For the first measure, the cases for different flexibility utilization from LECs are given in Table 4. In addition to this, Table 4 gives the P_i^{lim} values used in the optimization model. P_i^{lim} values have been calculated based on the peak value of baseline LEC profiles given in Fig. 5(a) and the peak shaving ratio r_{flex}. For example, the peak load of the LEC profile at bus 89 is 0.822 MW. Thus, with a peak shaving ratio of 0.05, P_i^{lim} comes out to be 0.78 MW ($= 0.822 - 0.05 \cdot 0.822$).

For the second measure, active power profiles are shown in Fig. 5(b), which is then used to calculate available reactive power using Eq. (1). Preliminary testing showed that reactive power provision from the FCS at bus 48 alone was not effective in mitigating voltage problems. Therefore, only the FCS at bus 78 was involved in active measures in the results presented below.

6. Results of economic assessment

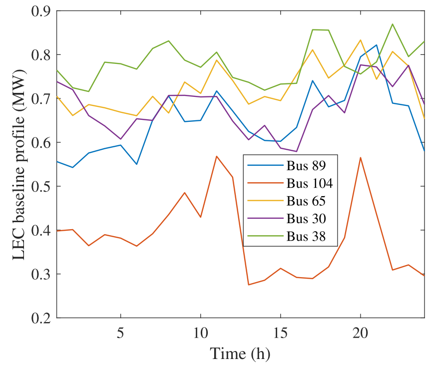
To give a clear illustration of the results from the main parts of the methodology, we first consider a simpler case only considering LECs in Section 6.1, before we assess and compare cases including both LECs and FCSs in Section 6.2.

6.1. Economic assessment: Scenario with only LEC

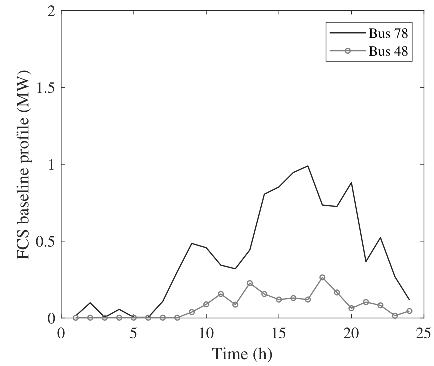
For simplicity of presentation, we first consider the load development scenario *LEC only* where it is assumed that no FCS will be integrated in the system over the planning horizon. The DSO grid planning model is run for the passive grid planning option and for the cases described in Table 4 with LEC flexibility utilization as an active measure. Fig. 6 shows the resulting grid development plan that is returned by the grid planning module, as explained in Section 4.1. It describes how the system is developed over the planning horizon to make the transition from the existing grid (in the reference year 2021) to the target grid (in 2030). Throughout the transition it visits a set of intermediate system solutions, and each system solution (sometimes also called an alternative [5]) is defined by a set of measures that have been implemented in the system. The figure illustrates how active measures will be implemented from 2025 ($y_{\mathrm{active}} = 4$) and how in addition more lines are being reinforced from 2028 onwards.

Fig. 7 compares accumulated costs over the 10-year planning horizon with (b) and without (a) the use of active measures in the grid planning. For this case, utilization of flexibility from LECs leads to a deferral of investments from year 4 to year 7, as well as a decrease in the accumulated grid investment costs over the planning horizon. The use of active measures results in an increase in operational costs, but the total accumulated costs at the end of the planning horizon are still lower with active measures.

Fig. 8 shows the present value of the total costs (investment costs and flexibility costs) for passive grid planning and active grid planning with varying degree of utilization of LEC flexibility. If the DSO plans for a higher utilization of flexibility, this will lower the future grid investment cost, but this comes at the expense of an increase in operational costs due to flexibility activation. For this case, the lowest total cost is achieved by a relatively modest utilization of flexibility (with a $r_{\mathrm{flex}} = 0.05$). The modest estimated benefit of LEC flexibility is partly due to an operational model that does not assume advanced and centralized



(a) Baseline profiles for new residential LEC loads to be added to the system.

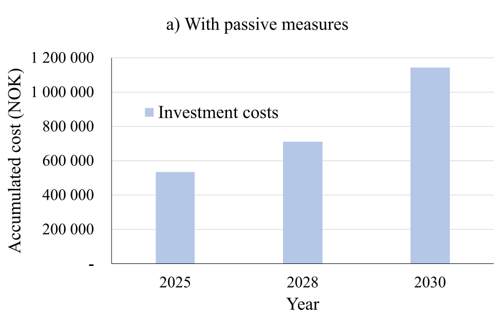


(b) Baseline profiles for new FCS loads to be added to the system.

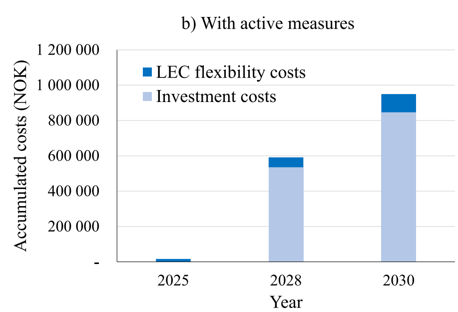
Fig. 5. Baseline profiles for new loads.

	Year									
System solution	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reinforced lines 5-7, 9-12										
Reinforced line 9-12										
Existing grid with active measure (LEC)										
Existing grid										
Accumulated investment costs (kNOK)	-	-	-	-	-	-	-	*535*	*535*	*846*

Fig. 6. Grid development plan for scenario with LECs only and active grid planning ($r_{flex} = 0.1$).



(a) Accumulated costs up to each year when grid investment are made according to the grid development plan for active measures



(b) compared with corresponding costs when including LEC flexibility utilization ($r_{flex} = 0.1$) as an active measure

Fig. 7. Accumulated costs up to each year.

optimization of the operation of the distribution system [28]. The DSO has, however, a potential to increase the operational benefits of the active measure if it is able to realize a smarter and more differentiated and dynamic activation of LEC flexibility.

What degree of utilization of LEC flexibility that gives the lowest present value of the total costs will depend on the value of several case-dependent and uncertain parameters. In Fig. 9, we illustrate the sensitivity of the total cost to the number of days per year that flexibility needs to be activated. This sensitivity can in this case study be investigated in a simple manner by varying the parameter n_1. It is seen that the level of flexibility use that minimizes total cost over the planning horizon relies on how often flexibility activation will be needed. In other words, this assumption will affect the DSO's decision on the extent to which it should plan for this active measure. If a significant amount of peak shaving is needed for more than around 45 days per year, planning with only passive measures ($r_{flex} = 0$) will give the lowest total costs. In Fig. 9, a dashed line is added to see

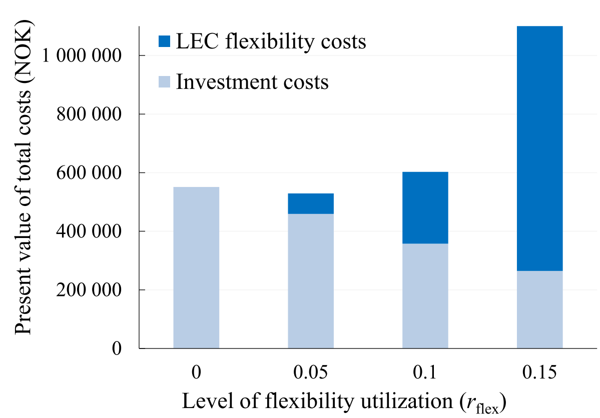


Fig. 8. Present value of total costs for the grid development plan with only passive measures (left) and increasing use of active measures (towards the right).

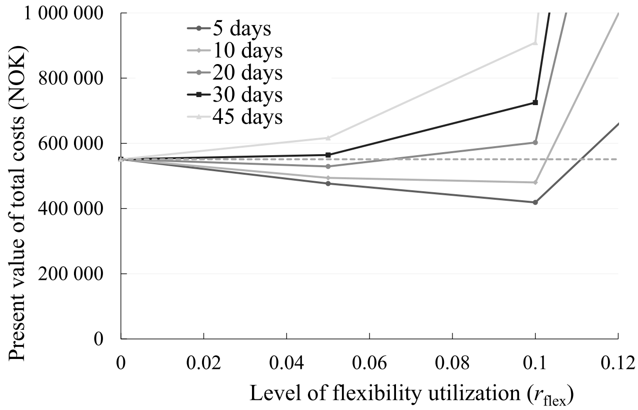


Fig. 9. Sensitivity of the total cost (present value of investment costs and operational costs) based on number of days per year that flexibility needs to be activated (n_1). The dashed line indicates the total cost with only passive measures ($r_{\text{flex}} = 0$). For points above the dashed line, use of LEC flexibility is not a cost-effective solution for the DSO.

which region of the (r_{flex}, n_1) parameter space where use of LEC flexibility will be cost-effective for the DSO compared to only using passive measures. For instance, if planning for a flexibility utilization level $r_{\text{flex}} = 0.1$, this will only be cost-effective if flexibility activation turns out to be needed less than around $n_1 = 20$ days per year. Based on how likely the DSO believes different values of n_1 are, it can use this analysis to estimate the likelihood that use of flexibility turns out to be cost-effective.

In the grid planning phase, other parameters such as the flexibility activation cost will also be uncertain. The sensitivity to this parameter will be investigated indirectly in Section 6.3.

6.2. Economic assessment: Considering both LEC and FCS as active measures

For demonstrating the methodology for a case with multiple active measures as part of the same grid development plan, we consider a second load development scenario *LEC and FCS*, where new FCSs as well as LECs are assumed to be added to the system during the planning horizon. FCSs requesting connection to the MV distribution grid is currently a challenge for Norwegian DSOs and is anticipated to be a rising challenge internationally for distribution grid planning. This section will explore the interactions between the FCSs and LECs as active measures and compare their benefits in the context of grid planning.

Fig. 10 compares the present value of grid development plans with different combinations of active measures (LEC and/or FCS) and passive measures (grid reinforcement). Here, $r_{\text{flex}} = 0.05$ is used for the level of flexibility utilization, as well as the default parameter values in Table 3. Without any use of active measures (case *Passive*), the grid investment costs are substantially higher than for the load development scenario without any FCS (Section 6.1). Utilizing only the potential flexibility of the LECs (case *Active: LEC*) can reduce the investment costs, but in this case the reduction is relatively modest and is offset by the increase in operational costs due to flexibility activation. Enabling flexibility of the FCS (case *Active: FCS*), on the other hand, reduces the present value of the investment costs by almost 70%. The significant benefit of utilizing FCS as an active measure in this case is due to the large reactive power capacity available at the converters interfacing the FCS loads with the grid. We have verified that the greatest operational benefits of FCSs for this case is obtained for the maximum reactive power injection allowed by the converter. The way this case was defined, reactive power provision as a

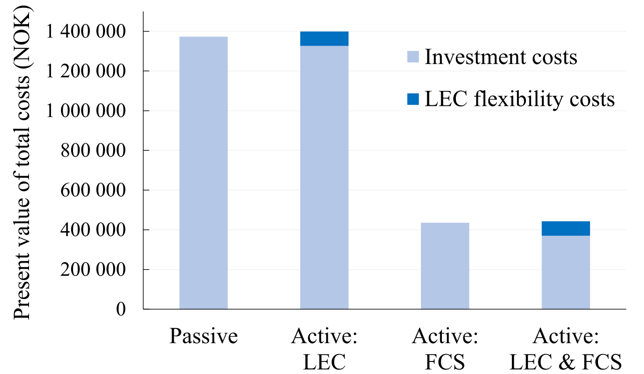


Fig. 10. Comparison of present value for grid planning with different combinations of active and passive measures. (Scenario: *LEC and FCS*.).

flexibility service comes at no cost to the DSO. As investigated in Section 6.3, any additional operational costs due to this active measures would need to be very large to offset the reduction in investment costs. Enabling utilization of LEC flexibility in addition (case *Active: LEC & FCS*) results in further reductions in the grid investment costs, but also in this case, these are modest and offset by increased operational costs.

To test the robustness of the conclusion from Fig. 10 that reactive power provision from FCS has great potential as an active measure, a simple sensitivity analysis is carried out. It tests the sensitivity to the assumption that the utilization of the FCSs remains constant over the planning horizon. In practice, the FCSs are likely to become more utilized year by year as a larger share of vehicles become electric, and the consequent increase in real power consumption will reduce the reactive power capacity available at the converters. For simplicity, the FCS load profiles are therefore scaled by a factor $(1+0.08 \cdot y)$ so that the FCS at bus 78 has a utilization of up to 50% in the peak load day of the system (as in Fig. 5(b)) but reaches a utilization of almost 100% in 2031. For this sensitivity case, the required grid investments become significantly higher than for the corresponding results shown in Fig. 10: Without active measures (corresponding to case *Passive* in Fig. 10) the present value increases from around 1.4 MNOK to around 3.7 MNOK; the present value with reactive power provision from FCS (corresponding to case *Active: FCS* in Fig. 10) increases from around 0.4 to around 1.0 MNOK. This means that for more conservative assumptions about the available reactive power capacity, using FCS as an active measures still reduces the present value of the investment costs by around 70% in this system.

6.3. Implications for the actors in the distribution system

It is assumed that the DSO is minimizing the total socio-economic cost in the system as a planning criterion. Therefore, the result of the economic assessment presented in the previous subsections illustrates the benefits for society as a whole of utilizing active measures. In this section, the results of the valuation methodology in Section 4.3 will be used to explore the implications (potential costs and benefits) for other actors, namely the LEC operator and the FCS operator.

From a socio-economic perspective, for a system with both LECs and FCSs within the system boundaries, the costs incurred by LECs for providing flexibility to the DSO can be seen as socio-economic losses. If these losses are compensated exactly by the DSO's payment for flexibility services, the economic assessment will be the same from the DSO's perspective as from the socio-economic perspective.

Table 5
Valuation of active measures.

Valuation metric	LEC only Active: LEC	LEC and FCS Active: LEC	LEC and FCS Active: FCS
c^{sd} (NOK/MWh)	1314	640	–
C^{op} (NOK/a)	7006	3542	71 367

In a business or market perspective, on the other hand, the LEC operator and DSO can negotiate a price for flexibility activation that may be higher than the costs incurred by the LEC. The business case of LEC flexibility provision can be investigated using a LEC perspective cost minimization model. This is outside of the scope of this work, but such a model can be integrated in the framework in future work. In negotiating a flexibility price, the LEC operator can justify a price that corresponds to the DSO's savings in terms of reduced investment costs, or in other words the DSO's willingness to pay for flexibility, considering the alternative cost of grid investments. The willingness to pay for shifting one MWh is calculated using Eq. (21) and shown in Table 5. Note that this value is an assumed average price throughout the analysis horizon, in real terms referred to 2021 cost level.

For the *LEC only* scenario, the societal value of the flexibility service is higher than the baseline flexibility price assumed in previous section (i.e., $c^{sd} = 1000$). This competitive cost of flexibility can be explained as the break-even load-shifting price that would make the two leftmost bars of the barplot in Fig. 8 have the same height. In the *LEC and FCS* scenario, on the other hand, use of LEC flexibility is not a cost-effective solution in the above economic assessment, which means that the DSO's willingness to pay is lower than the assumed baseline flexibility price.

For the economic assessment of the use of the FCS as an active measure, it was assumed that FCS reactive power can be controlled without interfering with EV charging and that the FCS operator incurs no costs in providing reactive power. This assumption is in line with the regulatory frameworks currently in place in most countries. One could however consider possible future frameworks where FCS operators could be remunerated for reactive power provision. Then, similarly as for LECs, the valuation methodology in Section 4.3 can be used to investigate the business case of a voltage support service from the FCS operator perspective. To be able to compare LEC and FCS, the willingness to pay for flexibility services (providing modification of active and reactive power, respectively) is quantified in terms of average annual competitive operational costs in the second row of Table 5. The results show that, at least for this particular case, the value of FCS flexibility services is much higher than for LEC flexibility services. For the FCS operator, the willingness to pay can also be analysed for different FCS converter sizes to consider the option of investing in oversizing the converter to increase the revenue from voltage support services.

7. Conclusion and further work

This paper has demonstrated the integration of active measures involving LECs and FCSs in a general framework for planning of active distribution grids. Active measures are also considered as temporary measures to defer grid investments and reduce the present value of the socio-economic costs of the grid development plan.

The framework and methodology allow different types of active measures to be valuated and compared. The results showed how the methodology can be used (1) in negotiating the price of active measures between the DSO and other actors (e.g., LEC and FCS operators) and (2) by the DSO in the selection of active measures in the planning phase (e.g., whether to utilize LEC and/or FCS flexibility).

In the case study, only two relatively simple and moderate load development scenarios were considered. For future work, the methodology can be applied to investigate more extreme cases, e.g. to represent the rapid electrification of transport on land and sea (with more FCSs and other charging infrastructure). It would also be interesting to explore the implications of a scenario where a majority of the existing loads are forming LECs. In addition to this, relatively high-level, exemplary operational models of active measures were used to demonstrate the methodology, their operational benefits were likely underestimated in the case study, and future work could investigate how the value of active measures could be increased through more optimized activation of flexibility.

The case study presented in this paper did not investigate the risks associated with the uncertainties in the long-term load development scenarios. In future work, the framework implementation will therefore be extended by complementing the optimization models presented here with simulations for quantifying the economic risks (e.g. overinvestment) and technical risks (e.g. undervoltage problems) for different scenarios and grid development solutions. The sensitivity analysis can also be extended to analyse the risk that flexibility may need to be activated so often that active measures will not be cost-effective compared to only grid investments.

CRediT authorship contribution statement

Rubi Rana: Conceptualization, Formal analysis, Investigation, Methodology, Software, Validation, Visualization, Writing – original draft. **Iver Bakken Sperstad:** Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Software, Validation, Visualization, Writing – original draft. **Bendik Nybakk Torsæter:** Conceptualization, Funding acquisition, Project administration, Writing – review & editing. **Henning Taxt:** Conceptualization, Funding acquisition, Project administration, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Datasets related to this article can be found at https://doi.org/10.5281/zenodo.7703070, hosted at Zenodo (Sperstad et al., 2023).

Acknowledgements

This work was supported by the project consortiums of the research projects Fine ("Flexible Integration of Local Energy Communities into the Norwegian Electricity Distribution System") and FuChar ("Grid and Charging Infrastructure of the Future") funded by the Research Council of Norway under Grant 308833 and Grant 295133, respectively. The work has also been funded by CINELDI - Centre for intelligent electricity distribution, an 8-year Research Centre under the FME-scheme (Centre for Environment-friendly Energy Research, 257626/E20). The authors would also like to thank Oddbjørn Gjerde, Merkebu Zenebe Degefa, Espen Flo Bødal, Susanne Sandell, and Olav Bjarte Fosso for their inputs to the work and useful discussions.

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