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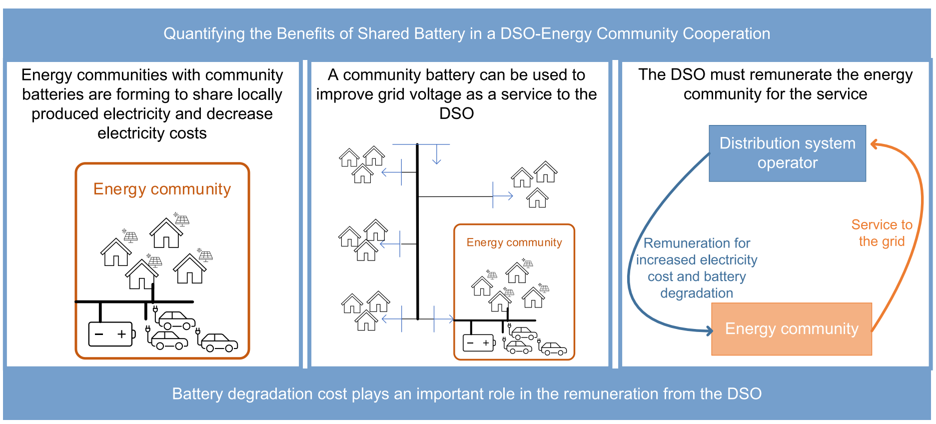
Quantifying the benefits of shared battery in a DSO-energy community cooperation

Kjersti Berg [a,*], Rubi Rana [b], Hossein Farahmand [a]

[a] Department of Electric Power Engineering, Norwegian University of Science and Technology (NTNU), O. S. Bragstads plass 2E, 7034 Trondheim, Norway

[b] Department of Energy Systems, SINTEF Energy Research, Sem Sælands vei 11, 7034 Trondheim, Norway

GRAPHICAL ABSTRACT



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ABSTRACT

Local energy communities are forming as a way for prosumers and consumers to invest in distributed renewable energy sources, community storage and share electricity. Meanwhile, several distribution grids have voltage problems at certain hours of the year. Local energy communities consisting of generation and storage units might be valuable flexible assets that the distribution system operator (DSO) can make use of. This article aims to study how a battery in an energy community can provide services to the distribution grid, by creating a linear optimisation model which includes power flow constraints and a battery degradation model. First, we investigate how the battery operation of an energy community impacts the voltage in the nearby buses. We find that when including the degradation model, the voltage limits are violated much less than when not including the degradation model. Next, we investigate how the battery operation differs when the energy community cooperates with an active DSO to share the battery use, and quantify how much the DSO should remunerate the energy community. We find that the energy community should get 15 € per year due to an increase in electricity and degradation costs, which equals an increase of 0.12%, compared to when the community is not providing a service. Finally, a sensitivity analysis is performed to determine which parameters are more important to consider. We find that voltage violations in the grid are sensitive to the battery replacement cost, electric vehicle charging peak and the average spot price, while the remuneration from the DSO is sensitive to the battery replacement cost. For small battery sizes and a low power-to-energy ratio, the community is not able to improve the voltage at all hours of the year.

* Corresponding author.
E-mail address: kjersti.berg@ntnu.no (K. Berg).

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Nomenclature

Parameters

δ	Cycle depth [%]
η	Battery charge and discharge efficiency [–]
$\Phi(\delta)$	Cycle depth stress function of battery [%]
$C^{B,rep}$	Replacement cost of battery [€/kWh]
C_t^{spot}	Electricity spot price in hour t [€/kWh]
C^{tar}	Volumetric grid tariff [€/kWh]
E^B	Energy capacity of battery [kWh]
$P_{j,t}^D$	Active power demand at bus j in hour t [kWh/h]
$P_{j,t}^{PV}$	PV production at bus j in hour t [kWh/h]
$Q_{j,t}^D$	Reactive power demand at bus j in hour t [kVArh/h]
R^{PE}	Power-to-energy ratio of battery [–]
R_{ij}	Resistance of line between bus i and j [Ω]
X_{ij}	Reactance of line between bus i and j [Ω]

Indices and sets

B	Set of buses where voltage constraint should be enforced
i,j	bus
S	Number of segments
s	degradation segment
T	Last hour of year
t	hour

Variables

C_s^{deg}	Battery degradation cost for segment s [€]
$p_{s,t}^{ch,seg}$	Battery charging for segment s in hour t [kWh/h]
p_t^{ch}	Battery charging in hour t [kWh/h]
$p_{s,t}^{disch,seg}$	Battery discharging for segment s in hour t [kWh/h]
p_t^{disch}	Battery discharging in hour t [kWh/h]
p_t^{exp}	Export to grid from EC bus in hour t [kWh/h]
$p_{ij,t}$	Active power flow between bus i and bus j in hour t [kWh/h]
$q_{ij,t}$	Reactive power flow between bus i and bus j in hour t [kVArh/h]
$soc_{s,t}^{seg}$	Battery state of charge for segment s in hour t [kWh]
soc_t	Battery state of charge in hour t [kWh]
$v_{i,t}$	Voltage at bus i in hour t [pu]

1. Introduction

The electricity distribution grid is changing as distributed energy resources are increasing in popularity and households are becoming active prosumers. A way for prosumers to organise and share electricity is by forming energy communities. As described in EU directives regarding Citizen and Renewable energy communities [1,2], the members of an energy community should be active, and the main objective of the community should not be to make profit, but rather to provide environmental, economic or social benefits for its members. A primary aspect of energy communities is collective assets such as storage systems, which the literature has demonstrated are more cost-effective than individual storage units [3,4].

Studies on energy communities have shown that photovoltaic (PV) panels and batteries are popular technologies in energy communities [5,6], as installation costs continue to decline. An increasing number of households in Norway are currently investing in PV panels owing to the increase in electricity prices over the previous year, as the electricity costs in Norway have historically been relatively low. Furthermore, the Norwegian Energy Regulatory Authority (NVE-RME) has proposed to change the regulation regarding sharing of electricity within properties [7], enabling houses and apartments located at the same property to share electricity generation up to 500 kW. With this proposition, sharing of electricity will also be possible in Norway, potentially leading to the formation of more energy communities. Additionally, since 2022, housing cooperatives in Norway are obliged to install electric vehicle (EV) chargers if requested by the residents [8].

The Norwegian distribution grid has many rural areas and long distances due to sparsely populated areas (Norway has a population density of 14 inhabitants/km^2). Rural feeders tend to have a high resistive characteristic, and in some cases, problems with over- or under-voltages breaching the limits of +/- 10% of nominal voltage (EN50160 standard) [9]. In some cases, the voltage is violated even though the households connected to the feeder are not exceeding their allowed import or export. In these cases, the distribution system operator (DSO) is responsible for improving the voltage quality, traditionally by upgrading lines and/or transformers. Furthermore, since the majority of household electricity use in Norway is due to electric heating [10], voltage limits are usually violated in only a few hours of the year when the outdoor temperature is especially low. In these hours, an active DSO could acquire flexibility services from households instead of reinforcing the grid, or at least to defer the grid reinforcement. Studies have investigated how grid-connected batteries operated by a DSO can improve the voltage [11–13]. However, EU legislation states that “Distribution system operators shall not own, develop, manage or operate energy storage facilities” [2]. Moreover, it would require the DSO to invest in an asset which is utilised only for some hours of the year. In this article, we investigate how an existing battery system owned by an energy community can improve the distribution grid voltage by providing a service to the DSO.

Energy communities can be an effective way for the DSO to acquire flexibility in hours where there are voltage problems. Flexible resources in energy communities can be manifold, from energy storage systems like hot water tanks to demand side responses such as shiftable loads or EV charging [14]. Both hot water tanks and shiftable loads are dependent on household demand, while EVs are stochastic in nature due to their mobility. Hence, their flexibility potential in a given hour is uncertain. Therefore, in this study, we focus on stationary battery storage, which has the advantage of being available at all hours.

Recently, power systems research has shown an increased interest in battery degradation due to the increased deployment of lithium-ion batteries [15–17]. Cyclic battery degradation depends on multiple factors, such as C-rate, temperature, depth-of-discharge, and average state-of-charge (SOC) [18]. Detailed degradation models are often non-linear and lead to a high computational burden when combined with optimisation models [19]. Therefore, many optimisation studies in power systems neglect battery degradation [5] or use linear power-energy models [19]. Such models often use a constraint-based approach where for instance, power, number of cycles per day, depth of discharge, and/or maximum and minimum SOC are constrained, leading to non-optimal solutions [20]. In the context of energy communities, examples of studies which include such constraints are [21–23]. If cyclic degradation is disregarded in optimisation models that minimise cost, the battery often charges and discharges heavily to perform energy arbitrage, which in practise would lead to a much lower lifetime [24,25]. One way to account for the cyclic degradation, while keeping the optimisation model linear, is to add a degradation cost in the objective function [19]. In this article, we investigate how an energy community and a DSO can cooperate to improve the voltage profile of a distribution

Table 1
Relevant literature on distribution grid impact from energy communities.

Ref.	Grid impact	Service to DSO	Battery	Battery degradation model	Power flow analysis
[4]	✓	✓	community	✓	✓
[40]	✓	✓	community	✓	X
[39]	✓	✓	community	X	X
[38]	✓	✓	community	X	✓
[21]	✓	X	community	X[a]	X
[32]	✓	X	X	X	X
[22]	✓	X	individual	X[a]	✓
[23]	✓	X[b]	individual	X[a]	✓
[31]	✓	✓[c]	X	X	✓

[a]has limits on SOC.
[b]service to reserve market.
[c]includes network constraints in market clearing.

grid - and how much the DSO should remunerate the energy community for this service. If the change in battery operation contributes to battery degradation, it should be accounted for when calculating how much the DSO should remunerate the energy community for providing the grid service.

1.1. Related literature

According to [5,26], there is limited literature focusing on how energy communities and PV-battery systems affect the distribution grid. Until now, most studies on energy communities have primarily focused on the sizing and siting of PV and battery systems [21,27–29], market designs [22,30,31], or the difference between individual and shared assets [3,32–37]. Few of these studies [21,22,32] have investigated how energy communities impact the grid, but not specifically focused on how the energy community operation can be changed to provide a grid service. One exception is [31], where a peer-to-peer market is cleared with grid constraints. Other studies, such as [23], do not investigate how the community can provide a local service, but rather services to the balancing reserve markets while considering congestions in the distribution grid.

A limited number of studies [4,38–40] have investigated how an energy community can improve the distribution grid voltage in cooperation with the DSO. Two ownership models of a community battery were compared in [40], where they found that the economic and environmental performance was slightly worse when there was a shared ownership of the battery between an aggregator and a DSO, compared to single ownership by the aggregator, but the differences were small. This study included a degradation model for the battery but did not consider power flow equations. Ref. [38] found that a community performing peak shaving helped reduce grid loading by up to 58%, compared to when the community was minimising its costs. The costs increased by only 0.3%. The battery model did not, however, include degradation.

Ref. [39] investigated the operation of flexible assets in energy communities and found that a grid-friendly strategy achieved a peak-power reduction of up to 55%. They also found that the cost difference between maximising economic benefits and the grid-friendly strategy was very low and therefore concluded that energy communities might be a cost-effective way to defer future grid reinforcements. They neglected both a degradation model for the battery and power flow equations. Ref. [4] studied how an energy community of 200 households could improve the voltage in the distribution grid, including degradation modelling. The battery operation was heuristic-based for self-consumption maximisation, and the main aim of the article was to investigate how to distribute energy use of shared assets among the community members. When comparing the annual bills of the community with and without grid constraints, they found an increase of 1874 £.

1.2. Contributions

To summarise the relevant literature and compare it to this article, Table 1 presents whether the references consider grid impact, service to the DSO, community battery, battery degradation model or power flow constraints. The primary objective of this article is to quantify the benefits of using community-owned battery storage for an energy community and a DSO. The electricity and degradation costs for the energy community are estimated by running an optimisation model with and without voltage constraints. This study examines a whole year, allowing a broader spectrum of analysis due to seasonal variations of load and PV in weeks, days and hours. Hence, the approach described here can give insights to both operation and planning of energy communities. A sensitivity analysis is performed to identify which parameters have the prominent impact on the remuneration from the DSO. In summary, the main contributions of this paper include:

- The paper presents a linear optimisation model which minimises the electricity and degradation costs for an energy community. The optimisation model includes linear battery degradation equations, which ensures that degradation costs are accounted for while maintaining a low complexity of the optimisation problem. The case studies show how the community-owned battery is used differently when voltage constraints are considered.
- The proposed model provides new insights for quantifying how much the DSO should remunerate the energy community for the voltage service.

1.3. Outline of article

The outline of this article is as follows: First, Section 2 explains the linear optimisation model created for this work. Section 3 explains the various input of the Norwegian case study used to showcase the model. Section 4 shows and discusses the main results from the case study, highlighting the impact of the degradation model and the service to the DSO. Finally, Section 5 concludes the article.

2. Method

Fig. 1 shows an overview of the input to and output from the optimisation model. The model takes the following input: hourly active and reactive load for each bus, hourly normalised PV production in each bus and the size of the PV system, and the hourly electricity spot price. Furthermore, the size and the power-to-energy (P2E) ratio of the community battery system must be specified, along with the grid tariff for the energy community. The battery degradation cost and the number of degradation segments are also given as an input as further explained in Section 2.3. Finally, the grid topology and resistance (R) and reactance (X) of the grid must be specified. The optimisation model then minimises the costs of the energy community, due to power flow and battery constraints. The model also includes optional constraints

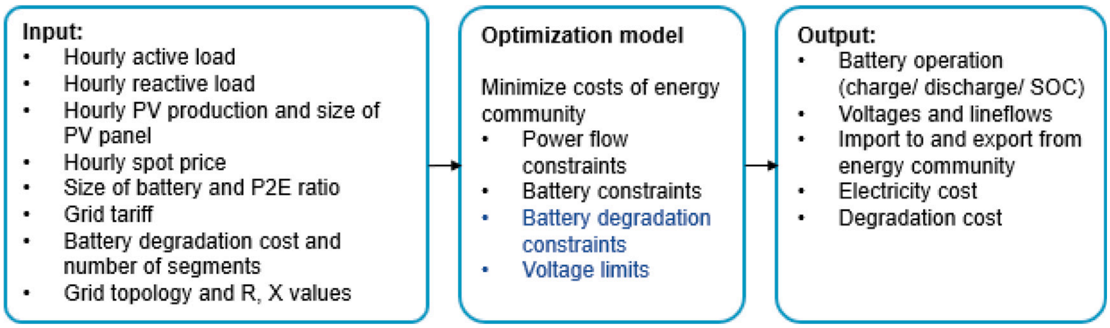


Fig. 1. Overview of input to and output from the optimisation model. The battery degradation and voltage constraints are marked in blue as they are not included in some of the cases.

for battery degradation and voltage limits, depending on the case, which will be further explained in Section 3. The model outputs the battery operation, the voltage and line flow of the grid, the import to and export from the energy community, the electricity costs of the community and the degradation cost of the battery.

2.1. Optimisation model

The optimisation model is shown in (1a)–(1t), see the nomenclature for an explanation of the variables and parameters. Perfect foresight is assumed, and the model is deterministic. (1a) is the objective of the model, which is to minimise operational costs related to electricity for the energy community and degradation cost of the battery. Import of electricity has a spot price, value-added tax (VAT) and a grid tariff, while it is assumed that the community can sell electricity for the spot price (as is the regulation in Norway).

Since the original AC power flow equations result in non-convex optimisation problems, the equations are often linearised or relaxed (through for instance semidefinite or second-order-cone programming) [41,42]. One common way to linearise is using the linear DistFlow (LinDistFlow) equations made for radial distribution grids [43]. The LinDistFlow equations assume that the line losses are negligible and have been shown to model power networks with satisfactory accuracy [44,45]. Constraints (1b)–(1g) cover the LinDistFlow constraints. (1b) describes the electricity produced and consumed in the bus of the energy community, while (1c) describes the same, but for the remaining buses. Note that since the objective requires separate variables for import and export, the line connected to the energy community (EC) is split into an import variable, $p_{ij,t}$ for j=EC bus, and an export variable, p_t^{exp}. This also requires a separate constraint depending on if the line in question is connected to the energy community (1d). (1e) describes the reactive power produced and consumed in each bus. (1f) describes the voltage dependence on the line resistance and reactance, where (1g) covers the EC bus.

Constraints (1h)–(1l) are constraints for the battery operation. (1h)–(1j) relate the SOC with the previous hour and the amount of electricity charged and discharged. The SOC of the final hour is set equal to the first hour. (1k)–(1l) restrict the charge and discharge to be lower than the battery inverter capacity, which is determined by the P2E ratio of the battery system, R^{PE}.

Constraints (1m)–(1q) for cyclic battery degradation are added as described in [46]. Each battery segment, s, has a cost which makes it more expensive the more segments the battery discharges through. This cost is added to the objective function to penalise heavy use of the battery. It ensures that the battery does not do arbitrage on very small price variations or discharge with high power, which would cause more harm to the battery in terms of a lower lifetime than benefit in terms of electricity cost savings. This model is chosen since it is piecewise linear.

Finally, (1r)–(1t) show the non-negativity constraints (see Box I).

Table 2
Case overview.

Case	Battery degradation cost included in objective function?	Voltage requirement included?
No battery	X	X
EC	✓	X
EC no deg.	X	X
EC+DSO	✓	✓
EC+DSO no deg.	X	✓

2.2. Energy community providing service to DSO

For cases where the battery is also utilised to provide a service to the DSO, the following constraint is included:

$$\underline{V}_i^2 \leq v_{i,t} \leq \overline{V}_i^2 \qquad i \in B, \forall t \tag{2}$$

where B is the set of buses where this voltage requirement must be fulfilled.

2.3. Battery degradation model

The battery degradation cost is found from [46]:

$$C_s^{deg} = \frac{C^{B,rep}}{\eta}(\Delta\Phi(\delta_s)) \tag{3}$$

where $C^{B,rep}$ is the replacement cost of the battery in €/kWh and $\Delta\Phi(\delta_s)$ is the stress due to the cycle depth δ_s of segment s in %.

3. Case

This section explains the Norwegian case study used to showcase the optimisation model. Four cases are run, as shown in Table 2. Case No battery is used as a reference case where the battery size is set to 0. In case EC (energy community), the battery is used to minimise the energy community's costs without enforcing constraint (2). Case EC no deg. is similar to case EC, however the degradation cost, $\sum_s C_s^{deg} p_{s,t}^{disch}$, is removed from the objective function. In case EC+DSO, the battery is now used to minimise costs for the energy community and to improve the voltage, hence constraint (2) is now included. Case EC+DSO no deg. is similar to case EC+DSO, however, the degradation cost is not considered in the objective function.

3.1. Input

Table 3 shows the input parameters. The following subsections describe the grid, household demand, PV production, spot prices and degradation cost input.

Objective:

$$\min \quad \sum_t \left[(C_t^{spot} + C^{tar}) p_{ECline,t}^{imp} - C_t^{spot} p_t^{exp} + \sum_s C_s^{deg} p_{s,t}^{disch,seg} \right] \quad (1a)$$

Power flow constraints:

$$p_{ij,t} - p_t^{exp} = \sum_{k:j\to k} p_{jk,t} + P_{j,t}^D - P_{j,t}^{PV} + p_t^{ch} - p_t^{disch} \qquad j = \text{EC bus}, \forall t \quad (1b)$$

$$p_{ij,t} = \sum_{k:j\to k} p_{jk,t} + P_{j,t}^D \qquad \forall j \neq \text{EC bus}, t \quad (1c)$$

$$p_{ij,t} = \sum_{k:j\to k} p_{jk,t} - p_t^{exp} + P_{j,t}^D \qquad \forall k = \text{EC bus}, t \quad (1d)$$

$$q_{ij,t} = \sum_{k:j\to k} q_{jk,t} + Q_{j,t}^D \qquad \forall j, t \quad (1e)$$

$$v_{j,t} = v_{i,t} - 2(R_{ij} p_{ij,t} + X_{ij} q_{ij,t}) \qquad \forall j \neq \text{EC bus}, t \quad (1f)$$

$$v_{j,t} = v_{i,t} - 2\left[R_{ij}(p_{ij,t} - p_t^{exp}) + X_{ij} q_{ij,t} \right] \qquad j = \text{EC bus}, \forall t \quad (1g)$$

Battery constraints:

$$soc_t = soc_{t-1} + \eta p_t^{ch} - \frac{1}{\eta} p_t^{disch} \qquad \forall t > 0 \quad (1h)$$

$$soc_t = soc_T + \eta p_t^{ch} - \frac{1}{\eta} p_t^{disch} \qquad \forall t = 0 \quad (1i)$$

$$soc_t \leq E^B \qquad \forall t \quad (1j)$$

$$p_t^{ch} \leq E^B R^{PE} \qquad \forall t \quad (1k)$$

$$p_t^{disch} \leq E^B R^{PE} \qquad \forall t \quad (1l)$$

Battery degradation constraints:

$$p_t^{ch} = \sum_s p_{s,t}^{ch,seg} \qquad \forall t \quad (1m)$$

$$p_t^{disch} = \sum_s p_{s,t}^{disch,seg} \qquad \forall t \quad (1n)$$

$$soc_{s,t}^{seg} \leq E^B / S \qquad \forall s, t \quad (1o)$$

$$soc_{s,t}^{seg} = soc_{s,t-1}^{seg} + \eta p_{s,t}^{ch,seg} - \frac{1}{\eta} p_{s,t}^{disch,seg} \qquad \forall s, t > 0 \quad (1p)$$

$$soc_{s,t}^{seg} = soc_{s,T}^{seg} + \eta p_{s,t}^{ch,seg} - \frac{1}{\eta} p_{s,t}^{disch,seg} \qquad \forall s, t = 0 \quad (1q)$$

Non-negativity constraints:

$$p_t^{exp}, p_{ECline,t}, p_t^{ch}, p_t^{disch}, soc_t \geq 0 \qquad \forall t \quad (1r)$$

$$v_{i,t} \geq 0 \qquad \forall i, t \quad (1s)$$

$$p_{s,t}^{ch,seg}, p_{s,t}^{disch,seg}, soc_{s,t}^{seg} \geq 0 \qquad \forall s, t \quad (1t)$$

Box I.

Table 3
Input parameters.

Parameter	Value	Unit
Battery efficiency, η	0.95	–
Battery replacement cost, $C^{B,rep}$	200	€/kWh
Battery size, e^B	120	kWh
PV size	8	kWp
No. degradation segments	8	–
Cosphi	0.99	–
EC bus	16	–
Grid tariff, C^{tar}	0.041	€/kWh
Value added tax (VAT)	0.25	–
P2E ratio, R^{PE}	0.5	–
Average spot price	0.05	€/kWh
Voltage limits, $\underline{V}_b$, $\overline{V}_b$	0.92, 1.08	pu
Buses where voltage limit is enforced, B	16, 17	–

3.1.1. Modified CIGRE LV distribution network with energy community

A modified version of the residential part of the CIGRE European LV distribution network [47] is shown in Fig. 2. There are loads connected to buses 0, 10, 14, 15, 16 and 17. The energy community is connected to bus 16, with household load, PV production, shared EV chargers and a shared community battery. The R/X values and length of lines can be found in [47]. To make the case study more similar to the Norwegian rural distribution grids, the length of all the lines has been multiplied with a factor of 1.9.

In cases EC+DSO and EC+DSO no deg., lower and upper voltage limits of 0.92 pu and 1.08 pu are used for buses 16 and 17 in (2).

3.1.2. Household demand, EV charging demand and PV production

Household demand of all load buses is based on hourly normalised data from 100 Norwegian households in 2015 [48]. Loads of the CIGRE grid are populated by adding random profiles to each load bus, before scaling them up to meet loads of the CIGRE European LV distribution

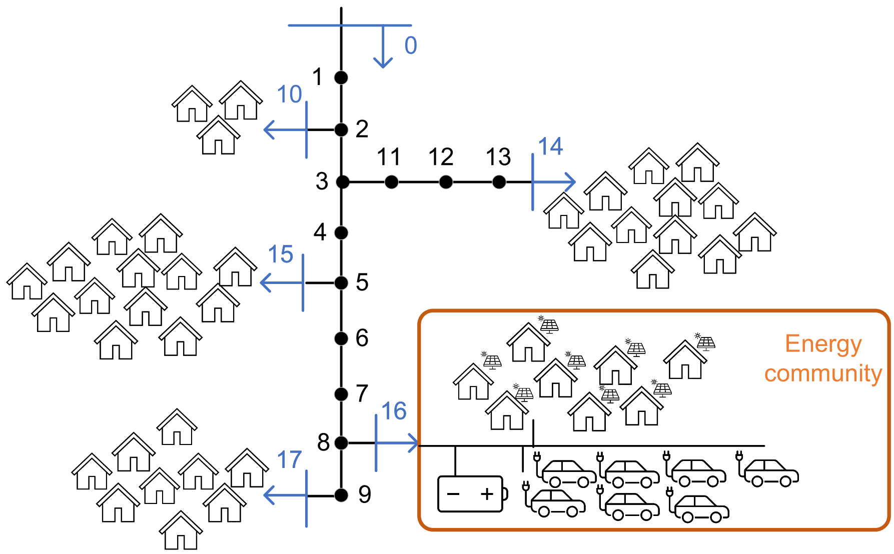


Fig. 2. Modified residential CIGRE European LV distribution network.

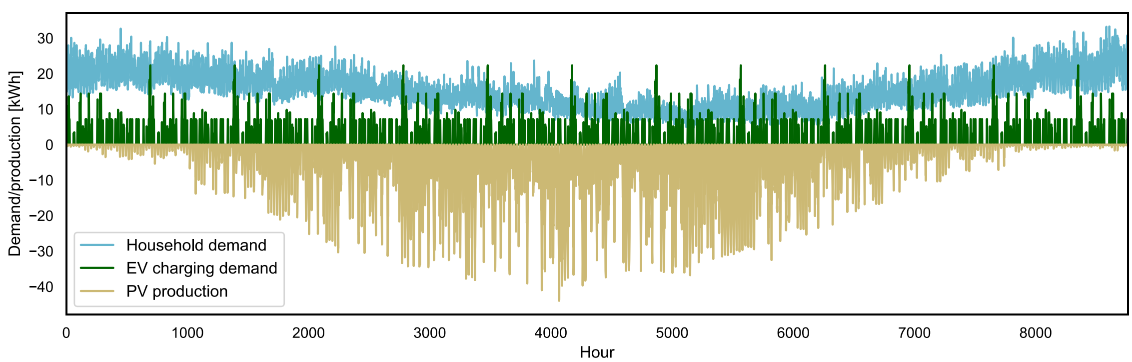


Fig. 3. Demand and production at EC bus.

Table 4
Max. load and no. of households at buses.

Bus	10	14	15	16	17
Max. load [kWh/h]	14.25	49.4	52.25	33.25	44.65
No. of households	3	12	13	8	10

network. Maximum load and number of households per load bus can be seen in Table 4. The aggregated load for each bus is shown in Fig. A.11.

The EV charging data is taken from a dataset on residential electric vehicle chargers for Norwegian apartment buildings [49]. The data used is the synthetic load profile of 7.2 kW common chargers from *Dataset 3b_Hourly EV loads - Aggregated shared*. Since the dataset starts 10 January 2019 and the number of shared chargers increased throughout the year, two modifications have been made to the dataset so that it is consistent with the other data in the case study: only data for seven and eight chargers are used, and the weekdays are shifted to correspond to the weekdays of 2015. Hence, the days in the dataset between 30 May and 24 June 2019 are used and repeated throughout the year.

The PV panels have the specifications from [50], and an assumed efficiency of 0.95. The power output from the PV system is calculated from measured irradiance and temperature data for Mære, Norway, as explained in more detail in [48]. The household demand, EV charging demand and PV production at the EC bus (16) can be seen in Fig. 3.

3.1.3. Spot price and grid tariff

The spot price from price zone NO3 for 2015 is used and scaled to match the predicted average spot price for Norway 2030 of 0.050 €/kWh [51]. The resulting spot price can be seen in Fig. 4 (excluding VAT). The energy-based grid tariff, C^{tar}, is set to 0.04126 €/kWh from the historical tariff of the Norwegian DSO Tensio TN [52].

3.1.4. Degradation cost

The cycle depth stress function of a lithium-ion nickel manganese cobalt (NMC) battery is used to calculate the degradation cost [46,53]:

$$\Phi(\delta) = (5.24 \cdot 10^{-4})\delta^{2.03} \tag{4}$$

Using (3) along with a battery replacement cost of 200 €/kWh [54] and eight segments, the degradation cost segments are calculated to be between 0.013 and 0.2095 €/kWh as shown in Table 5.

3.2. Loss calculation

Since the LinDistFlow equations do not account for losses, a load flow analysis is done in pandapower post-optimisation. The hourly values for demand, generation, battery charge and discharge are given as input for all cases, and the resulting line losses are reported.

3.3. Sensitivity

To analyse the impact of different parameters on the results, the optimisation is run for different inputs of PV size, battery size, P2E ratio, max. EV charging, the average spot price level and the battery replacement cost. The input is shown in Table 6.

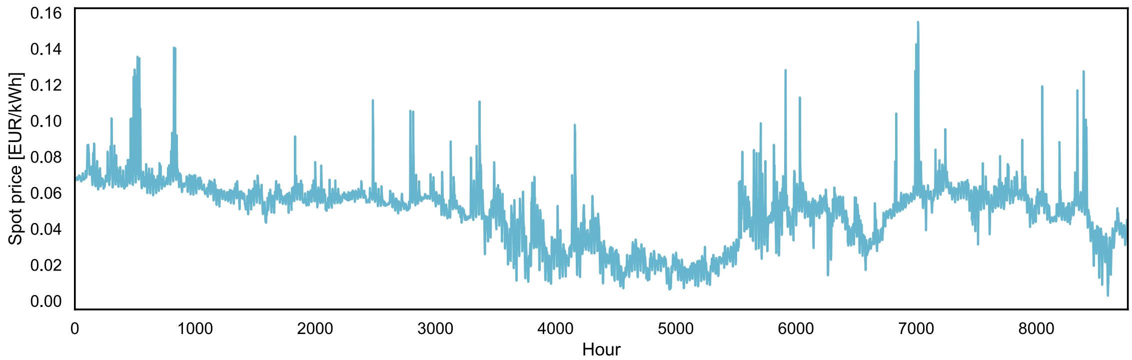


Fig. 4. Electricity spot price for NO3 from 2015, scaled to an average level of 0.050 €/kWh [51].

Table 5
Degradation cost segments.

Segment, s	1	2	3	4	5	6	7	8
C_s^{deg} [€/kWh]	0.0130	0.0400	0.0676	0.0956	0.1238	0.1522	0.1808	0.2095

Table 6
Sensitivity input.

PV size [kWp]	Battery size [kWh]	P2E ratio	EV max. charging [kWh/h]	Average spot price [€/kWh]	Battery replacement cost [€/kWh]
6.48	96	0.1	17.9	0.040	100
7.2	108	0.3	20.1	0.045	150
8	120	0.5	22.3	0.050	200
8.8	132	0.7	24.6	0.055	250
9.68	144	0.9	26.8	0.060	300

4. Results and discussion

The optimisation model is run for the given case study for 8760 h. In this section, we first illustrate how the degradation model affects the battery operation and voltage violations. Second, we illustrate how the battery operation changes when the community coordinates with the DSO to keep within voltage limits. Third, we summarise the results for the whole year and show how this service impacts the costs and battery use for the community. Finally, we investigate how sensitive the results are with respect to the input parameters before limitations of the study are addressed.

4.1. Degradation model effect on battery operation

Fig. 5 shows the results for one week in January for cases EC and EC no deg. The top graph shows the residual demand for the EC bus, with and without the battery. The middle graph shows the battery charge, discharge and SOC, while the lower graph shows the voltage at buses 16 and 17, which are the two buses where the voltage requirement must be fulfilled. In Fig. 5(a), it can be seen that the battery is used in five of the seven days even though there is no surplus energy due to low irradiance in winter. Hence, the battery is doing arbitrage on the spot price without considering the stress on the battery, and this leads to several drops in voltage below the voltage limit. When the degradation model is included, in Fig. 5(b), the battery is used a lot less, since the variation in spot price is not high enough compared to the degradation cost.

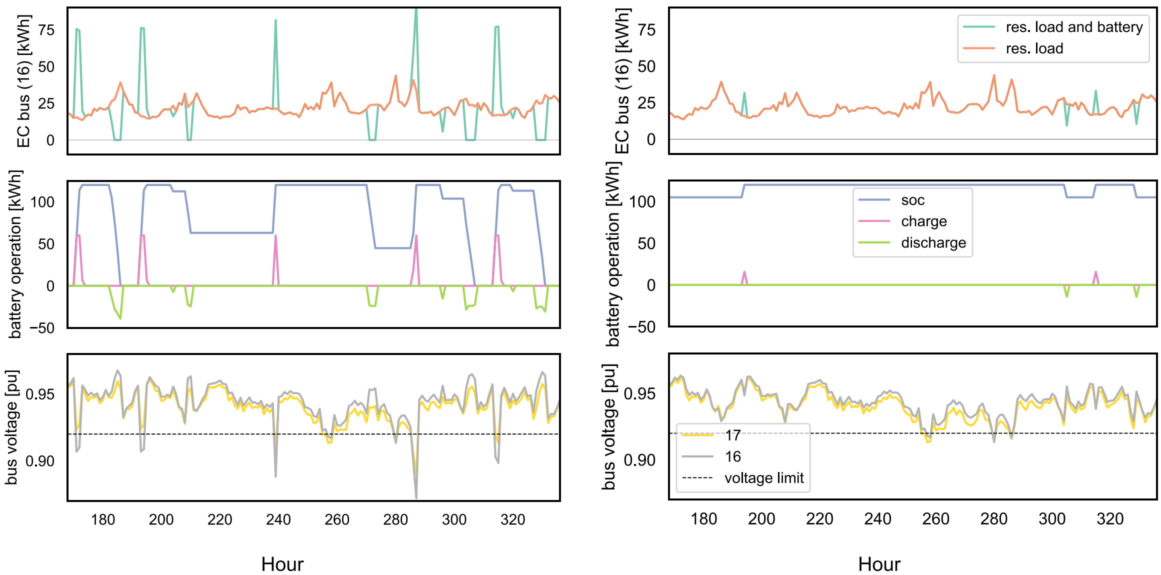
Fig. 6 shows the results for one week in June for cases EC and EC no deg. In Fig. 6(a) it can be seen that the battery is charged to 100% almost every day of the week due to a surplus of PV production. As a result, the voltage is quite stable except for two-three hours where the battery suddenly discharges or charges a lot, causing a spike in the voltage. In Fig. 6(b), when the degradation model is included, a lot of the self-produced energy from the PV generation is actually exported because it is more profitable to spare the battery than to charge from PV generation due to low spot price. Due to the lower usage of the battery, the voltage varies more throughout the week but avoids the sudden drops and spikes in voltage. Note also that the voltage is nowhere near the maximum voltage limit of 1.08 pu, due to a high load in the grid also in summer (ref. Fig. A.11).

4.2. Energy community coordinating with DSO

Fig. 7 illustrates the difference between cases EC (a) and EC+DSO (b), for the last three weeks in December. Note that these two cases both include the degradation model. From Fig. 7(a), we observe that the voltage is below the limit for several hours and that the battery is being used for energy arbitrage since there is no surplus energy from the PV. In case EC+DSO, the battery keeps the voltage at buses 16 and 17 above the voltage limit at all hours, which requires only a slightly different battery operation. Interestingly, one of the voltage drops that should be avoided in Fig. 7(a) (at approx. hour 8600) is created by the battery, because it is charging at maximum capacity (60 kWh/h). In Fig. 7(b), we observe that the battery limits the charging to avoid the voltage from dropping below 0.92 pu. In other words, the battery does not only remove voltage problems which occur due to high load, but it also avoids *causing* a voltage problem in the grid.

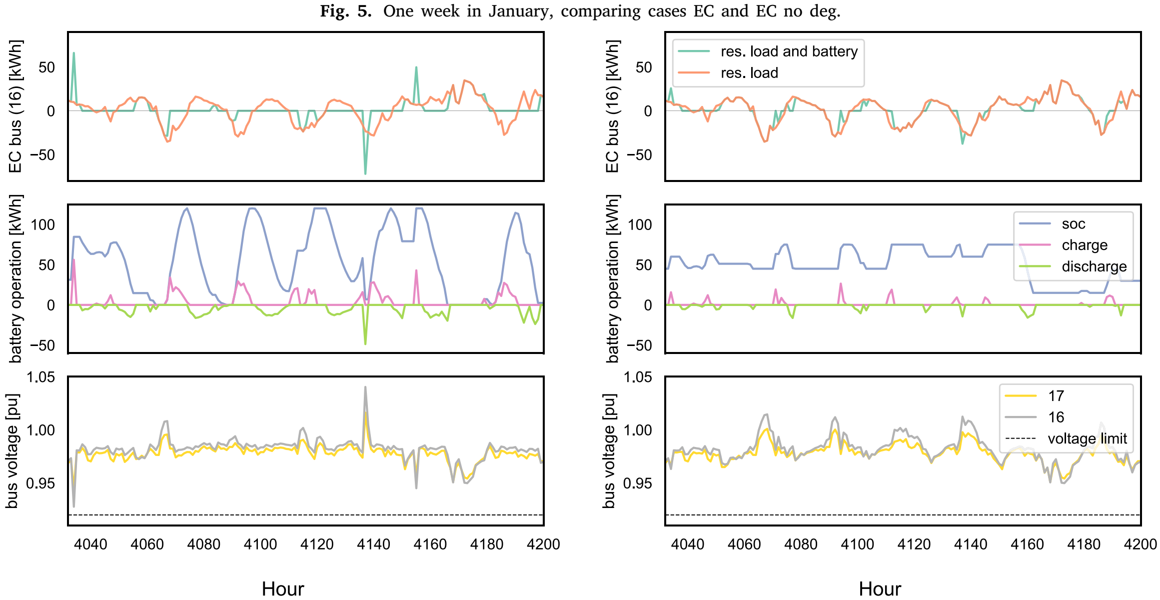
4.3. Yearly results of cases

Fig. 8 shows the voltages at buses 16 and 17 for cases EC no deg., EC and EC+DSO. Here we can observe that when not including the degradation model (upper graph), the battery is often charging at the same time as the voltage is below the limit. This occurs less when the degradation model is included (middle graph), indicating that many of the voltage problems in the upper graph are caused by the battery. There are, however, also many hours where the voltage is below 0.92 pu and the battery is not charging. Finally, the lower graph shows how the battery operation is changed to keep the voltages within the voltage limit.



(a) EC no deg. (b) EC

Fig. 5. One week in January, comparing cases EC and EC no deg.



(a) EC no deg (b) EC

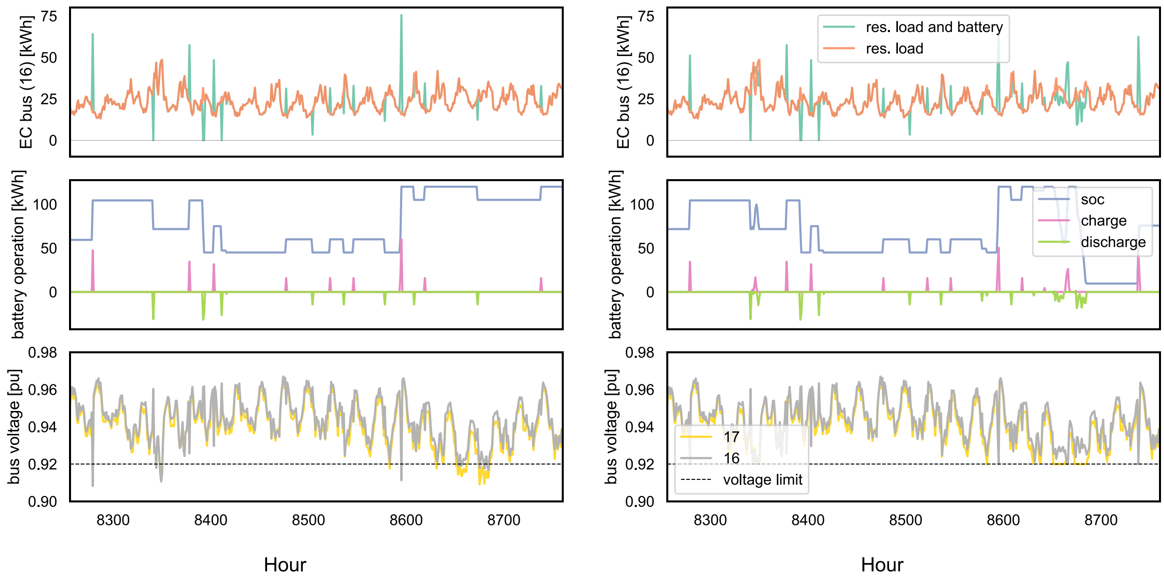
Fig. 6. One week in June, comparing cases EC and EC no deg.

Table 7 compares the electricity and degradation costs for all cases, both with and without the degradation model. Note that cases EC no deg. and EC+DSO no deg. correspond to the column named no degradation. Comparing the reference case with case EC, the electricity cost decreases by 267 € due to battery use, while the degradation cost increases by 121 €. Comparing cases EC and EC+DSO, the electricity cost increases by 5 €, and the degradation cost increases by 10 €. In other words, the total remuneration needed from the DSO to cover the additional costs for the energy community is 15 € per year. From the technical results in Table 8, we observe that the voltage violations at bus 17 is 38 h both in the reference case and in case EC. At bus 16, however, the voltage violations increase due to the battery operation, in addition to a lower minimum voltage.

Comparing cases EC and EC no deg., the electricity cost reduces by 343 €, but the degradation cost increases by 2299 €. This is connected to the battery usage shown in Table 8, where we observe that the battery is used substantially more in case EC no deg. (3371 vs 1370 h). Not considering degradation also leads to a lower minimum voltage of 0.872 pu due to the battery operation. Also, the voltage is violated 184 h at bus 16, compared to 25 h when degradation is considered. At bus 17, the voltage is violated 76 h, compared to 38 h. This increase in voltage violations is created solely from the battery operation, as we can compare with the reference case. All voltage violations occur in winter (November-February) in case EC, and the maximum voltage limit of 1.08 pu is not violated in any of the cases. Finally, we can observe from Table 7 that case EC+DSO no deg. has a lower degradation cost compared to case EC no deg. The reason for this is that the battery must limit its charging and discharging when the voltage restriction is included, which also leads to a lower degradation.

4.4. Impact on distribution grid losses

Since the LinDistFlow equations neglect line losses, a power flow has been run in pandapower post-optimisation to determine the losses in the distribution grid. From Table 9 we can see that the battery decreases the losses in the grid by 51 kWh, when comparing case EC



(a) EC (b) EC+DSO

Fig. 7. Last three weeks in December, comparing cases EC and EC+DSO.

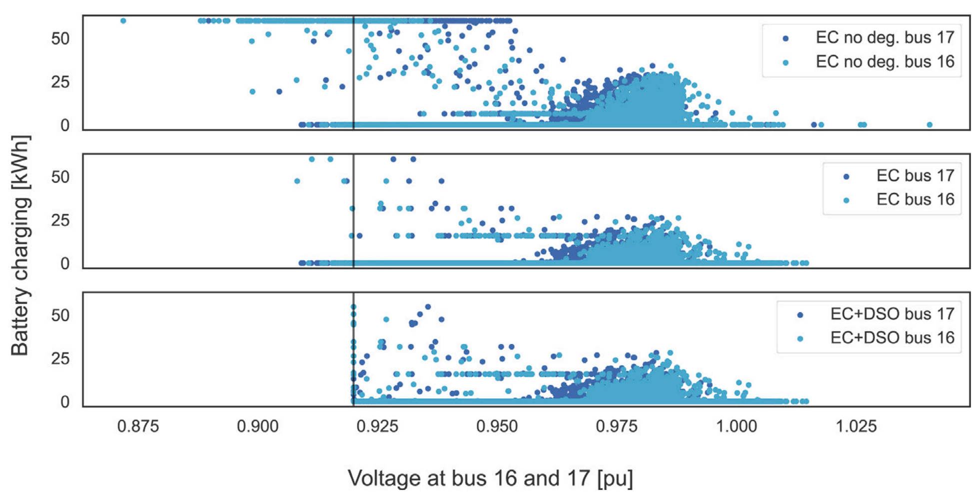


Fig. 8. Battery charging vs. voltages for cases EC no deg., EC and EC+DSO.

with case no battery. In case EC+DSO, when the energy community is providing a service to the DSO, the losses are further decreased by 8 kWh. Comparing cases EC and EC no deg., we see that the losses increase by 859 kWh when not accounting for degradation. Hence, including degradation does not only contribute to an improved voltage profile but also reduces losses in the grid.

4.5. Sensitivity analysis

In this section, we demonstrate the sensitivity of the results to varying input data. The reader is referred back to Table 6 to see the different sensitivity inputs, and all sensitivity results can be found in Tables B.10 and B.11.

4.5.1. Voltage violations

Fig. 9 shows the hours of voltage violation at buses 16 and 17 together with the lowest voltage for the different sensitivity input. Compared to bus 16, the voltage violations are always higher at bus 17, with 35 h as the lowest and 42 h as the highest. The most sensitive parameter is the EV charging peak, where the number of voltage violations ranges from 35 to 41 at bus 17. A higher EV charging peak leads to more voltage violations, and the charging profile of the EV is responsible for the majority of the voltage violations. The minimum voltage is, however, quite stable at 0.908 pu.

The average spot price of 0.06 €/kWh leads to a higher number of voltage violations compared to lower spot prices, due to more arbitrage from the battery. However, as the graph shows, it is not necessarily true that a lower average spot price will result in fewer voltage violations. Similarly, a higher battery replacement cost does not necessarily lead to a decrease in voltage violations, although that is the trend. The lowest battery replacement cost leads to the highest number of voltage violations and the voltage violations decrease until a cost of 250 €/kWh. The lowest voltage decreases for higher average spot prices but is quite stable around 0.909 pu. A battery replacement cost of 100 €/kWh gives the lowest voltage reported, at 0.894 pu.

Furthermore, the PV size has no impact on the voltage violations or the lowest voltage. This result is case-specific and is due to the fact that household demand in Norway is high in winter, while the solar irradiance is low (see Fig. 3). When the size of the battery is increased, there is a higher charging capacity, which results in an increase in the number of voltage violations (the P2E ratio is fixed at 0.5 when varying

Table 7
Yearly costs for energy community [€].

Case	With degradation		No degradation	
	Electricity cost	Degradation cost	Electricity cost	Degradation cost
No battery (ref.)	12 801	0		
EC	12 534	121	12 191	2420
EC+DSO	12 539	131	12 195	2401
Difference EC and EC+DSO	5	10	4	−19

Table 8
Yearly technical results for battery and network.

Case	With degradation			No degradation		
	Battery hours	Hours of voltage violation at bus 16, 17	Lowest voltage [pu][a]	Battery hours	Hours of voltage violation at bus 16, 17	Lowest voltage [pu][a]
No battery (ref.)	0	19, 38	0.909			
EC	1370	25, 38	0.908	3371	184, 76	0.872
EC+DSO	1432	0, 0	0.92	3441	0, 0	0.92

[a]Lowest voltage means the minimum voltage at bus 16 or 17.

Table 9
Yearly total losses for the CIGRE LV grid obtained post-optimisation [kWh].

Case	With degradation	No degradation
No battery (ref.)	32,128	
EC	32,077	32,936
EC+DSO	32,069	32,725
Difference EC and EC+DSO	−8	−211

the battery size, so the charging capacity increases with the battery size). Consequently, the lowest voltage drops to 0.90 pu for the largest battery. The same logic follows when looking at the P2E ratio: a higher ratio gives more voltage violations since the battery can charge with a higher power, and the voltage drops here are as severe as for the lowest battery replacement cost.

4.5.2. Remuneration from DSO

Fig. 10 shows the difference in cost between cases EC and EC+DSO, which can be interpreted as the remuneration that the DSO must pay to the community for providing this service.

The most sensitive parameter is the battery replacement cost, ranging from 9 to 21 €. We also observe that the ratio between the electricity and degradation cost is changing for the different replacement costs. A higher EV charging peak also gives a higher remuneration, which is solely due to an increase in degradation cost. A larger battery gives a lower remuneration, but it differs whether it is due to lower degradation cost or electricity cost. In general, a larger battery gives lower electricity cost, both for case EC and EC+DSO.

The average spot price always gives a remuneration of approx. 14 €, but it can be seen that the ratio between degradation and electricity cost changes for the different spot prices. This is due to the trade-off in the optimisation model: energy arbitrage or degradation of the battery. When the spot price is high, the battery is willing to accept a higher degradation cost due to higher savings in electricity cost.

For battery sizes of 96 and 108 kWh, and a P2E ratio of 0.1, the battery system is not able to provide the service to the DSO at all hours, and the optimisation model gives no solution. Input parameters of PV size and P2E ratio (except for a ratio of 0.1) have a very small impact on remuneration.

4.6. Limitations of study

In this study, we only consider a volumetric tariff, not demand charges or other tariffs that give incentives to lower the peak demand. This would have added an additional term in the objective function, which would lower the peak consumption and probably lead to fewer voltage violations.

A time resolution of one hour averages the PV production, household demand and EV charging, and therefore probably understates the charging and discharging capacity needed from the battery system. We expect that a higher resolution for PV production, household demand and EV charging demand would give more voltage violations due to

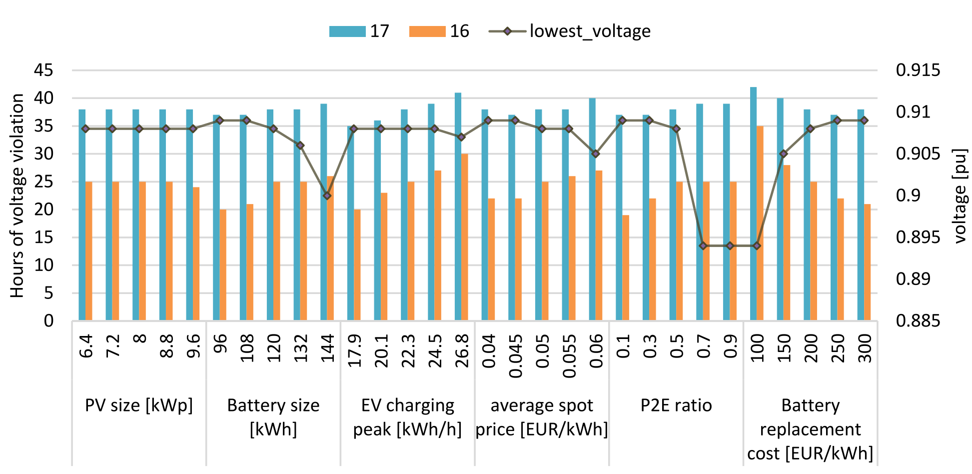


Fig. 9. Number of hours where the voltage limit is violated and minimum voltage for sensitivity analysis in case EC.

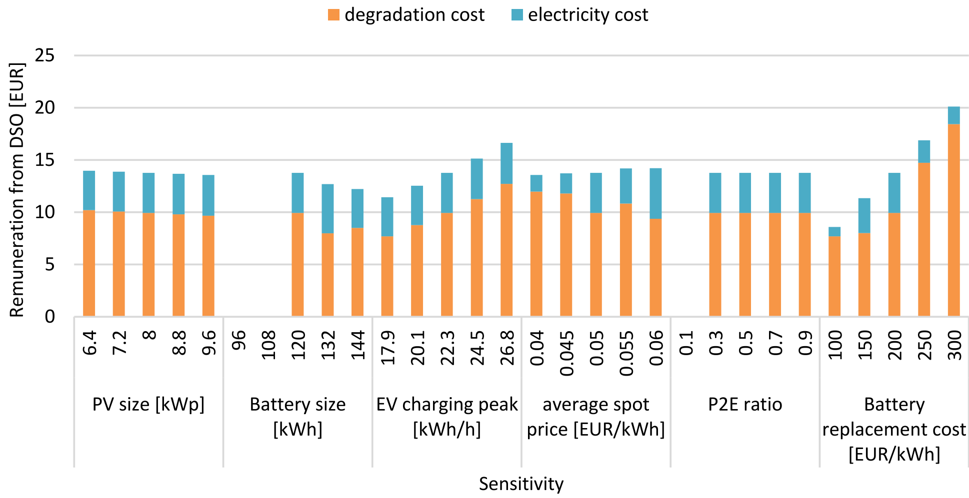


Fig. 10. Difference in yearly costs for cases EC and EC+DSO (in other words, the remuneration needed from the DSO to cover the costs for the community).

higher peaks in import and export. This would again lead to the need for a higher P2E ratio, and perhaps energy capacity, of the battery system to resolve the voltage problems in the grid in case EC+DSO. Higher and more frequent peaks would lead to more charging and discharging from the battery, which again would give a higher battery degradation cost.

Furthermore, we have assumed a perfect foresight model, which lets the battery operate with perfect information about the consumption, production and, thereby, the voltage in the grid. The sensitivity analysis compensates for the lack of uncertainty in our model, which has captured the effects of different levels of spot prices, EV charging peaks and PV size. However, the sensitivity analysis uses the same profiles/trends and only changes the level of the profile. The future spot price is expected to be more variable than the historical records, affecting our results. A more variable spot price could lead to a more significant difference in electricity costs for cases EC and EC+DSO, meaning that the remuneration from the DSO would increase.

Finally, an energy community can consist of flexibility assets other than battery energy storage, such as hot water tanks or load shifting, which could impact the voltage violations and the remuneration from the DSO. This kind of flexibility would also be less costly than a stationary battery but has the limitation of not always being available, as mentioned in Section 1.

5. Conclusion

The primary objective of this article was to study how an energy community and a DSO can coordinate to improve the voltage profile in the distribution grid. This was done by using a realistic model of community battery operation, taking into account battery degradation.

From our results and the sensitivity analysis performed, we observed that battery operation does affect both the voltage of the bus where it is connected and neighbouring buses. For the case study we investigated, the battery did actually cause some voltage problems due to arbitrage, mostly in the bus where the energy community was connected. This result is of importance for customers who are connected to the same bus as an energy community, as the community might actually create voltage problems for itself and other customers connected to the same bus. From Table 8, we see that the degradation model has a great impact on the voltage violations. When the battery is more restrictive on charging and discharging to diminish the battery degradation, it also leads to fewer spikes in voltage. Additionally, the losses in the grid are reduced when the battery provides the grid service. In other words: a battery-friendly operation is also a grid-friendly operation. The number of hours of voltage violations increased by 636% at the community bus and 100% at the neighbouring bus (17) when degradation was not considered, compared to when it was considered.

Moreover, our results show that the cost difference for the community, and thereby the remuneration needed from the DSO, was very low. It amounted to 15 € per year, which equals 0.12%. This result is similar to those reported by [4,38–40]. Ref. [38] reported a cost increase of 0.3% when doing peak shaving (note battery degradation was not considered), and [4] reported a cost increase of 1.6% when including grid constraints. The sensitivity analysis showed a range of 9–21 € in remuneration per year, which equals 0.07–0.17%, where the battery replacement cost was the most sensitive parameter.

The sensitivity analysis also showed that for some energy community configurations, the battery size or the inverter capacity was too low to perform the service throughout the whole year. Another interesting finding is that the battery is not always solving a voltage problem, it is sometimes merely avoiding creating a voltage problem. As shown in Fig. 10, the degradation cost had the major part in the remuneration from the DSO. If degradation cost would not be considered, the energy community would be remunerated less than their real cost of providing this service.

The case studied in this article was made with Norwegian data, and the results must be interpreted with this in mind. Since Norwegian households use electricity for space and water heating, their peak electricity consumption is in winter, which is also when the irradiance is the lowest. In summer, when the irradiance is the highest, the consumption is much lower. This stands in contrast to Southern European countries where households use more electricity in summer due to cooling [55]. The sensitivity analysis showed that increasing the PV size did not reduce voltage violations and that it had little impact on the remuneration from the DSO. Also, there were no over-voltage challenges, most likely due to the low share of PV in the grid. These results could be very different for countries with different profiles for household electricity demand and PV generation.

The practical agreement between the DSO and the energy community has not been addressed in this study. However, a more practical interpretation of our results is that an energy community with a stationary battery can coordinate with the DSO to improve the distribution grid voltage, without the need for a very large remuneration. Moreover, if this were put into effect, we would suggest that the community and DSO collaborate together to ensure that the battery characteristics (its energy and power capacity) would be sufficient to address the voltage problems in the grid.

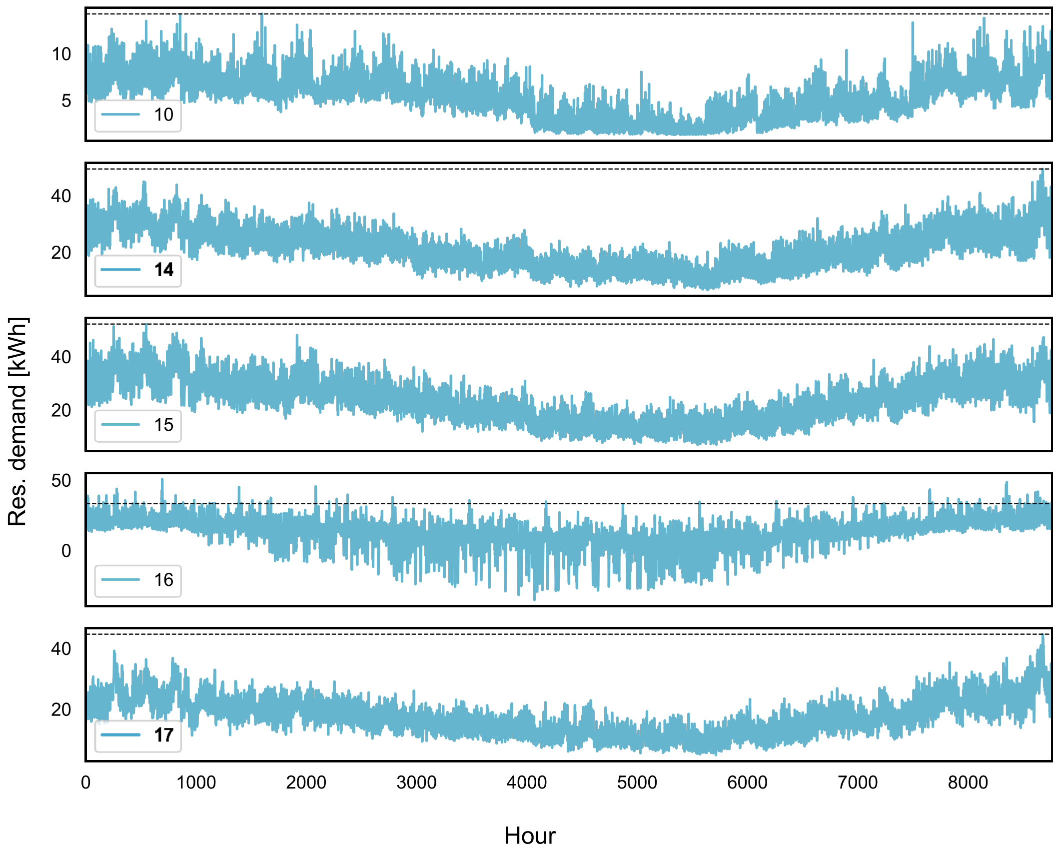


Fig. A.11. Demand per bus. Stippled line shows the load specified by the CIGRE European LV distribution network [47].

Table B.10
Sensitivity analysis costs [€].

Case		EC		EC+DSO	
		electricity cost	deg. cost	electricity cost	deg. cost
PV size [kWp]	6.4	13 082	101	13 086	111
	7.2	12 802	112	12 807	122
	8	12 534	121	12 539	131
	8.8	12 278	130	12 283	140
	9.6	12 032	137	12 037	147
Battery size [kWh]	96	12 569	108		
	108	12 552	114		
	120	12 534	121	12 539	131
	132	12 519	127	12 524	135
	144	12 504	132	12 509	141
EV charging peak [kWh/h]	17.9	12 255	121	12 260	129
	20.1	12 394	121	12 399	130
	22.3	12 534	121	12 539	131
	24.5	12 674	121	12 679	132
	26.8	12 814	121	12 819	134
Average spot price [€/kWh]	0.04	11 014	105	11 016	117
	0.045	11 778	110	11 780	122
	0.05	12 534	121	12 539	131
	0.055	13 296	127	13 300	138
	0.06	14 051	137	14 057	146
P2E ratio	0.1	12 551	110		
	0.3	12 534	121	12 539	131
	0.5	12 534	121	12 539	131
	0.7	12 534	121	12 539	131
	0.9	12 534	121	12 539	131
Battery replacement cost [€/kWh]	100	12 430	138	12 431	146
	150	12 502	119	12 506	127
	200	12 534	121	12 539	131
	250	12 585	94	12 588	109
	300	12 612	84	12 614	102

Table B.11
Sensitivity analysis technical results case EC.

		Battery hours	Voltage violation hours at bus 16, 17	Lowest voltage [pu]
PV size [kWp]	6.4	1217	25, 38	0.908
	7.2	1326	25, 38	0.908
	8	1370	25, 38	0.908
	8.8	1449	25, 38	0.908
	9.6	1482	24, 38	0.908
Battery size [kWh]	96	1271	20, 37	0.909
	108	1327	21, 37	0.909
	120	1370	25, 38	0.908
	132	1411	25, 38	0.906
	144	1458	26, 39	0.9
EV charging peak [kWh/h]	17.9	1385	20, 35	0.908
	20.1	1378	23, 36	0.908
	22.3	1370	25, 38	0.908
	24.5	1363	27, 39	0.908
	26.8	1359	30, 41	0.907
Average spot price [€/kWh]	0.04	1296	22, 38	0.909
	0.045	1327	22, 37	0.909
	0.05	1370	25, 38	0.908
	0.055	1396	26, 38	0.908
	0.06	1436	27, 40	0.905
P2E ratio	0.1	1541	19, 37	0.909
	0.3	1374	22, 37	0.909
	0.5	1370	25, 38	0.908
	0.7	1367	25, 39	0.894
	0.9	1367	25, 39	0.894
Battery replacement cost [€/kWh]	100	1797	35, 42	0.894
	150	1509	28, 40	0.905
	200	1370	25, 38	0.908
	250	1163	22, 37	0.909
	300	1065	21, 38	0.909

CRediT authorship contribution statement

Kjersti Berg: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Writing – original draft, Visualization. **Rubi Rana:** Methodology, Software, Validation, Writing – review & editing. **Hossein Farahmand:** Conceptualization, Writing – review & editing, Supervision.

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

The data used in the article is published in Data in Brief.

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Appendix A. Input data

See Fig. A.11.

Appendix B. Sensitivity analysis results

See Tables B.10 and B.11.

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