# The impact of degradation on the investment and operation of a community battery for multiple services

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***Abstract*—The emergence of local energy communities (LECs) introduces new concepts and dynamics to the operations of distribution grids. An important part of LECs is the shared ownership or control of assets such as photovoltaic systems and batteries. The aim of this article is to investigate how degradation impacts the investment and operation of a community battery which performs multiple services in a LEC. Two different grid tariffs are investigated: energy-based and demand charges. The case study set in Norway 2030 shows that the lifetime of the battery is significantly shortened when not considering degradation, highlighting the need to include cyclic degradation in models that investigates the profitability in investment and operational problems with batteries. In the case of a demand charge grid tariff, the expected lifetime was shortened by 6 years.**

***Index Terms*—Local energy community, Energy management system, Battery degradation, Grid tariffs**

## I. Introduction

Local energy communities (LECs) are emerging as a way for prosumers and consumers to be actively engaged in using locally produced energy sources, while being connected to the distribution network. The members of a LEC often have shared ownership and control of assets such as community photovoltaics (PV) and community batteries [1]. Studies such as [1], [2] have shown that community-owned batteries are better for relieving the grid through peak shaving or self-consumption, compared to individually owned batteries.

Although there is no fuel cost related to batteries, there is still a cost of using them as the lifetime is limited. However, this is often ignored in literature, resulting in sub-optimal operation of batteries which in reality has high, non-counted costs. When included, optimal operation of batteries participating in day-head and reserve markets changes significantly [3]. The need for proper degradation modeling when participating in electricity markets with batteries has resulted in new methods to consider the cycle ageing mechanisms of lithium-ion (Li-ion) batteries, mostly based on factoring the cycle ageing [4], [5]. This type of approach has been suggested in multi-market optimisation [6], which are also relevant for LECs as the battery is meant to provide multiple services, such as arbitrage, self-consumption and reducing peak imports. A shared community battery for reducing costs while providing ancillary services was proposed in [7], but focuses more on participation in balancing markets. Ref. [8] studies how to maximise investment returns of a battery while considering a cyclic degradation cost, but the battery is grid-connected and not in a LEC. Ref. [9] presents a techno-economic optimisation model to analyse the economic viability of a PV-battery system for different residential customer groups. However, cyclic degradation of the battery is not considered, only calendaric degradation. Our hypothesis is that cyclic degradation of the battery must be included in an investment and operational problem because it will affect the investment decisions and the expected lifetime of the battery.

The aim of this article is to investigate how battery degradation impacts the investment and operation of a community battery which performs multiple services in a LEC (reduce peak import, arbitrage, peak shaving, self-consumption). The main contributions of the work presented in this article are:

- Optimisation models for investment and operation of shared PV and battery system in a LEC, including cyclic degradation cost.
- Evaluation of how two different grid tariff schemes impact battery operation and degradation.
- Evaluation of how the battery performs multiple services for the LEC when degradation cost is included.

## II. Method

This section describes the optimisation models developed. The objective is to minimise both the investment costs of a shared PV system and battery, as well as operational costs related to electricity for the LEC, as illustrated in Fig. 1. It is assumed that the LEC shares the investment costs and the electricity costs.

### A. Optimisation models

There are four cases as shown in Fig. 2, where each case refers to an optimisation model. In the energy tariff (ET) cases, the LEC has an energy-based grid tariff, where the LEC pays a grid tariff only based on the energy imported. In the demand charges (DC) cases, the LEC has a demand charge grid tariff which is often used for commercial buildings in Norway. The

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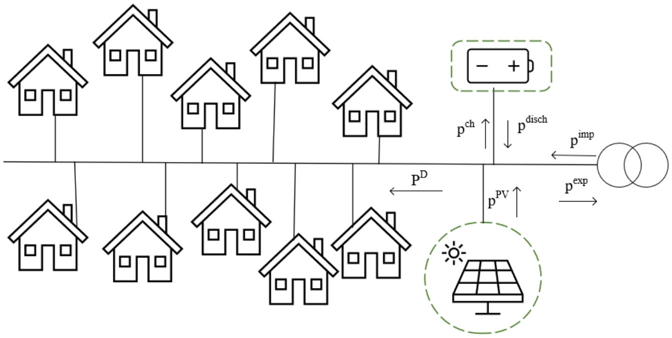


Fig. 1. Overview of LEC with shared PV and battery system

cost each month is decided from the monthly peak power, see [10] for more details.

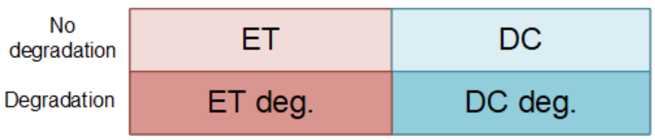


Fig. 2. Overview of cases

*1) ET case:* The ET case does not consider degradation. The model is shown in (1a)-(1l), see the nomenclature for an explanation of the variables and parameters. Eq. (1a) is the objective of the model, which minimises investment and operational costs. Eq. (1b) is the power balance, (1c) restrict the installed PV power, while (1d) and (1e) restrict the import from the grid. The power balance includes a curtailment variable to ensure feasibility in cases where the excess PV power exceeds the export limit. Eqs. (1f)-(1h) are state-of-charge (SOC) constraints for the battery. Eqs. (1i)-(1j) restrict the charge and discharge to be lower than available energy in the battery, and it is assumed that the power rating of the battery is equal to the battery capacity rating (C-rate of 1).

$$\min \quad C^B CRF^B e^B + C^{PV} CRF^{PV} p^{PV} + \sum_t \left[(C_t^{spot} + C^{tar,e}) p_t^{imp} - C_t^{spot} p_t^{exp}\right] \tag{1a}$$

$$P_t^D - p^{PV} P_t^{PV} + p_t^{exp} - p_t^{imp} + p_t^{ch} - p_t^{disch} + p_t^{PV,c} = 0 \quad \forall t \tag{1b}$$

$$p^{PV} \leq P^{PV,max} \tag{1c}$$

$$p_t^{imp} \leq P^{imp,max} \quad \forall t \tag{1d}$$

$$p_t^{exp} \leq P^{exp,max} \quad \forall t \tag{1e}$$

$$soc_t = soc_{t-1} + \eta p_t^{ch} - \frac{1}{\eta} p_t^{disch} \quad \forall t > 0 \tag{1f}$$

$$soc_t = soc_T + \eta p_t^{ch} - \frac{1}{\eta} p_t^{disch} \quad \forall t = 0 \tag{1g}$$

$$soc_t \leq e^B \quad \forall t \tag{1h}$$

$$p_t^{ch} \leq e^B \quad \forall t \tag{1i}$$

$$p_t^{disch} \leq e^B \quad \forall t \tag{1j}$$

$$e^B, p^{PV} \geq 0 \tag{1k}$$

$$p_t^{imp}, p_t^{exp}, p_t^{ch}, p_t^{disch}, soc_t, p_t^{PV,c} \geq 0 \quad \forall t \tag{1l}$$

*2) ET deg. case:* The ET deg. case considers degradation. Here, the model from the ET case is modified by adding a degradation cost to the objective function as shown in (2).

$$\min \quad C^B CRF^B e^B + C^{PV} CRF^{PV} p^{PV} + \sum_t \left[(C_t^{spot} + C^{tar,e}) p_t^{imp} - C_t^{spot} p_t^{exp}\right] + \sum_t \beta_t^{deg} \tag{2}$$

Constraints (3a)-(3g) for battery degradation and non-negativity are added as described in [5], [11].

$$\beta_t^{deg} = \sum_j C_j^{deg} p_{jt}^{disch,seg} \quad \forall t \tag{3a}$$

$$p_{,t}^{ch} = \sum_j p_{jt}^{ch,seg} \quad \forall t \tag{3b}$$

$$p_t^{disch} = \sum_j p_{jt}^{disch,seg} \quad \forall t \tag{3c}$$

$$soc_{jt}^{seg} \leq \frac{e^B}{J} \quad \forall j, t \tag{3d}$$

$$soc_{jt}^{seg} = soc_{jt-1}^{seg} + \eta p_{jt}^{ch,seg} - \frac{1}{\eta} p_{jt}^{disch,seg} \quad \forall j, t > 0 \tag{3e}$$

$$soc_{jt}^{seg} = soc_{jT}^{seg} + \eta p_{jt}^{ch,seg} - \frac{1}{\eta} p_{jt}^{disch,seg} \quad \forall j, t = 0 \tag{3f}$$

$$p_{jt}^{ch,seg}, p_{jt}^{disch,seg}, soc_{jt}^{seg} \geq 0 \quad \forall j, t \tag{3g}$$

*3) DC case:* In the DC case, degradation is not considered. The model from the ET case is modified by adding a monthly demand charge to the objective function as shown in (4a). Also, constraints (4b)-(4c) are added.

$$\min \quad C^B CRF^B e^B + C^{PV} CRF^{PV} p^{PV} + \sum_t \left[(C_t^{spot} + C^{tar,e}) p_t^{imp} - C_t^{spot} p_t^{exp}\right] + \sum_m p_m^{max} C_m^{tar,d} \tag{4a}$$

$$p_t^{imp} \leq p_m^{max} \quad \forall t \tag{4b}$$

$$p_m^{max} \geq 0 \quad \forall m \tag{4c}$$

*4) DC deg. case:* In the DC deg. case, degradation is considered. The model is equal to the DC case, except the objective function is replaced with (5).

$$\min \quad C^B CRF^B e^B + C^{PV} CRF^{PV} p^{PV} + \sum_t \left[(C_t^{spot} + C^{tar,e}) p_t^{imp} - C_t^{spot} p_t^{exp}\right] + \sum_t \beta_t^{deg} + \sum_m p_m^{max} C_m^{tar,d} \tag{5}$$

### *B. Battery specifications and degradation*

The battery system is assumed to be a Li-ion nickel manganese cobalt (NMC) battery which follows the following cycle depth stress function [5], [12]:

$$\Phi(\delta) = (5.24 \cdot 10^{-4}) \delta^{2.03} \tag{6}$$

where $\Phi$ is the cycle depth stress and $\delta$ is the cycle depth. The degradation cost is then found from [5]:

$$C_j^{deg} = \frac{C^{B,rep}}{\eta} (\Delta\Phi(\delta_j)) \tag{7}$$

where $C^{B,rep}$ is the replacement cost of the battery in NOK/kWh and $\Delta\Phi(\delta_j)$ is the size of the cycle depth of segment $j$ in %.

### C. Annualised investment costs

Since the cases are run for one year, the investment costs for the battery system is annualised by a capital recovery factor:

$$CRF^B = \frac{i(1+i)^{n^B}}{(1+i)^{n^B} - 1} \tag{8}$$

where $n^B$ is the lifetime of the battery in years, and $i$ is the interest rate. The investment cost for the PV system is annualised in the same manner.

## III. Case study

The case study is set to Norway in 2030. Demand and PV production data are based on hourly data from 2015 while the spot price level and installation costs for PV and battery are based on cost projections for 2030. Total demand for the ten households in the LEC is shown in Fig. 3, based on the normalised household data described in [13] multiplied with a peak load of 6 kWh/h. It is assumed that there is a restriction on the distribution grid where the LEC is connected, leading to an import limit of 35 kWh/h as indicated in the figure. Without the battery, this limit would be violated in ten hours of the year.

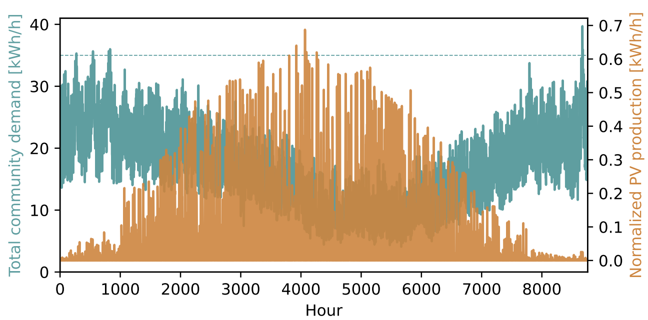


Fig. 3. Total demand of households in LEC and normalized PV production. Dashed line shows import limit of 35 kWh/h.

TABLE I
Input (same for all cases)

| Parameter | Value | Unit |
|---|---|---|
| $P^{imp,max}$, $P^{exp,max}$ | 35 | kWh/h |
| $\eta$ | 0.95 | - |
| $i$ | 0.051 | % |
| $C^B$ | 2000 [14][a] | NOK/kWh |
| $C^{PV}$ | 8000 [15][b] | NOK/kWp |
| $C^{B,rep}$ | $CRF^B C^B$ | NOK/kWh |
| $n^{PV}$ | 30 | years |
| $n^B$ | 10 | years |

[a] IRENA projections for Li-ion NMC batteries in 2030 are approx. 200 USD/kWh, which corresponds to 1975 NOK/kWh
[b] IRENA projections for PV system costs in 2030 are in the range of 340-834 USD/kW, which corresponds to 3358-8200 NOK/kW

Tab. I summarises the input which is the same for all cases. The PV panels have the specifications from [16], and an assumed efficiency of 0.95. The power output from the PV system is calculated from irradiance and temperature data for Maere, Norway, as explained in more detail in [13]. The replacement cost for the battery, used to find the degradation cost in (7), is assumed to be the annualised investment cost of the battery since the analysis is carried out over one year. Fig. 4 illustrates the idea behind this assumption. For this case study, the battery degradation cycle depth stress function is linearised by four segments.

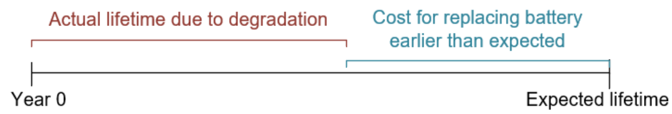


Fig. 4. Replacement cost as degradation cost

It is assumed that the spot prices in 2030 will be higher than the prices for 2015. The average spot price in 2015 was 0.19 NOK/kWh, while the future scenarios for spot prices in Norway are assumed to have an average of 0.52 NOK/kWh [17]. Therefore, the spot prices for NO3 prize zone in Norway for 2015 were multiplied with 2.75. The resulting electricity spot price used in the case studies, including VAT (25 %), is shown in Fig. 5.

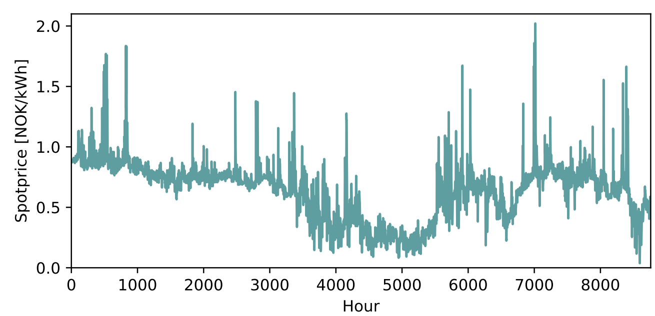


Fig. 5. Projected spot price for 2030 including VAT (25 %)

The grid tariffs are based on tariffs from the Norwegian DSO Tensio TN [18]: The ET case has an energy tariff, $C^{tar,e}$, of 0.4126 NOK/kWh and no demand charge. The DC case has an energy tariff, $C^{tar,e}$, of 0.2564 NOK/kWh and a demand charge, $C^{tar,D}$, of 89 NOK/kW-peak in winter months (Nov.-Feb.) and 13 NOK/kW-peak in summer months (May-Oct.). These numbers include consumption tax and VAT (25%).

## IV. Results and discussion

This section shows the results for the four cases when run for one year with hourly time-resolution.

### A. Battery operation and degradation

Fig. 6 shows the battery operation in January for ET deg. and DC deg. cases. Due to the demand charges grid tariff, the battery peak shaves demand above 31.4 kWh/h, indicated by the dashed line. The plots for SOC and degradation cost indicate that the battery finds profitability in peak shaving in the DC deg. case, even though this amounts to a higher degradation cost.

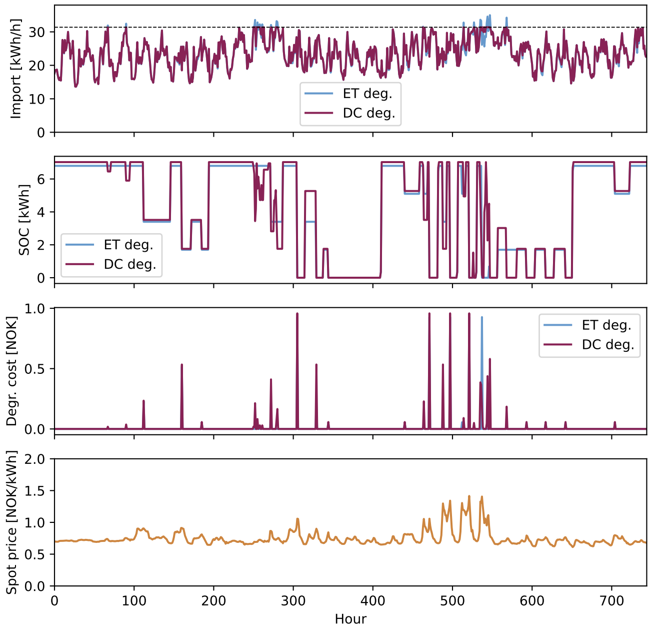


Fig. 6. ET deg. and DC deg. cases in January

Fig. 7 shows the battery operation in October for cases DC and DC deg. The battery peak shaves demand above 22.7 kWh/h, indicated by the dashed line. In the DC case, the battery is doing arbitrage on the spot price in almost all hours where there is a variation in the price. In the DC deg. case, the battery is more restrictive to when it responds to price variations, because it does not find it profitable to do arbitrage on small price variations when it leads to a high degradation cost.

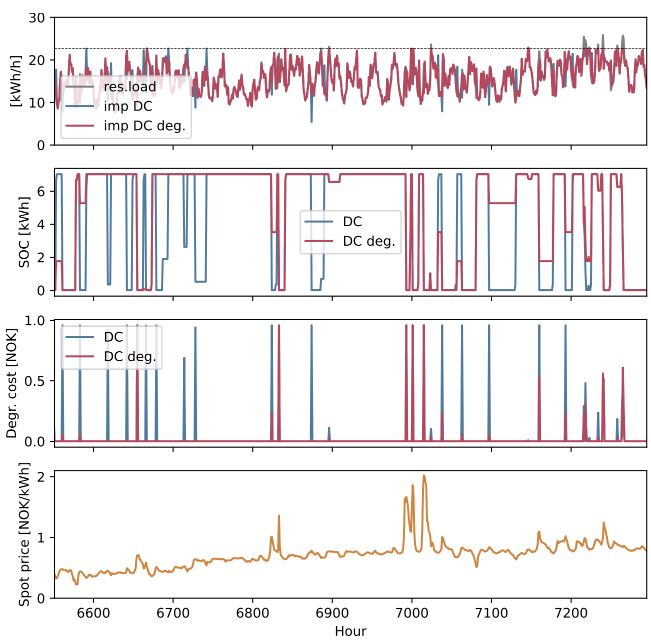


Fig. 7. DC and DC deg. case for October

Fig. 8 shows the battery operation for ET and ET deg. cases for one week in June. In the ET deg. case, the battery does not prioritise to charge all of the excess PV power and therefore exports some energy during the first day. When looking closely at the hours of export, we see that the battery balances some of the PV production but not all. This is due to the non-linear degradation cost of using the battery. Essentially, the battery ”fuel cost” is low enough for balancing using shallow cycles, but only using the cheapest segments of the battery. This preservation of battery lifetime is not captured in the ET case, which is an important feature of the degradation model.

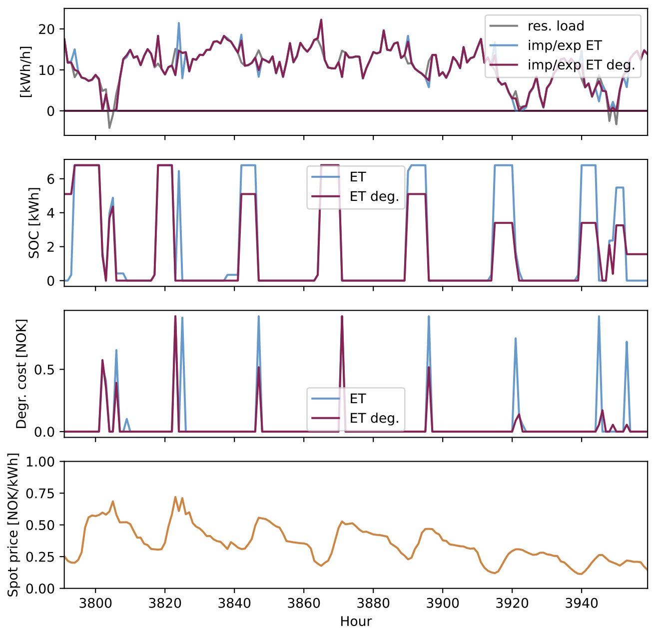


Fig. 8. ET and ET deg. cases for 8.-14. June

Fig. 9 shows the battery operation in December for ET and ET deg. case. The battery peak shaves the demand to meet the import limit of 35 kWh/h. It can also be seen that the battery operation of ET and ET deg. agree when there is very little spot price variation from hour 8100-8190.

Fig. 10 shows the accumulated degradation costs for all cases. As expected, the degradation cost is increasing much faster when degradation is not considered. Cases ET and DC show a clear distinction between the two grid tariffs. After approx. hour 500, the utilisation of the battery in the DC case is higher compared to the ET case. This is caused by the difference in grid tariffs along with the fact that the ET case has PV production. After approx. hour 3400, the degradation cost for the ET case is increasing faster than for the DC case, due to self-consumption of PV power and the fact that demand charges are lower in the summer months. At approx. 5800 hours the two cases are almost at the same level, until the DC case again increases faster due to higher demand charges in the winter months, in addition to almost no excess power from the PV system in the ET case. When looking at the cases ET deg. and DC deg. (dashed lines), they follow the same trend as the cases without degradation, except for one thing: they actually cross at hour 5300. This is because the ET deg. case is

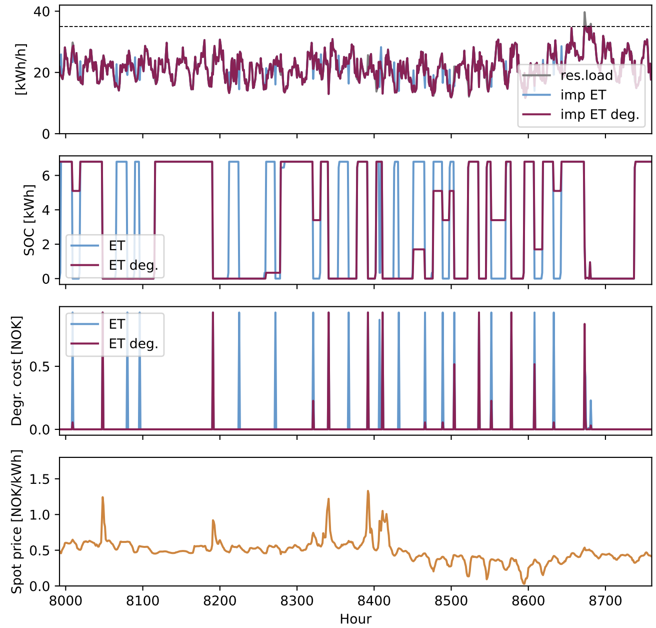


Fig. 9. ET and ET deg. cases for December

maximising self-consumption of PV power and doing arbitrage while the spot price is around 1.0 and 1.5 NOK/kWh (see Fig. 5).

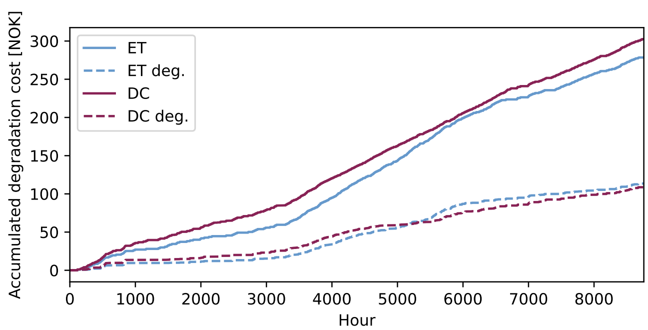


Fig. 10. Accumulated degradation costs for each case, with and without degradation

## B. Yearly summary

Tab. II shows the results for all cases. The battery size is approx. equal, 6.8 and 7.0 kWh, and for this case study the main reason for installing a battery is to meet the restriction on grid import. The model did not find it profitable to invest in a PV system for the cases DC and DC deg. This difference in PV investment reflects on the results for grid exchange, where there is approx. 14,000 kWh more import from the grid in the DC case compared to ET case. A significant reason for the lack of PV investments under demand charges, is that self-consumption saves less in terms of grid tariffs, as the energy term is much lower. Although the number of cycles are relatively similar between cases ET deg. and DC deg., the reasons are different. Under demand charges, it is profitable to avoid peak loads to save on the costly peak import hours, whereas energy-based tariffs has little incentive for peak shaving, but rather benefits from self-consumption of PV production. Essentially, the grid tariff structure impacts heavily which services the battery finds profitable.

The number of full cycles in the ET case is 1.9 times higher than the ET deg. case. Subsequently, if we assume that the battery lifetime is 2,000 cycles at full discharge cycles, the lifetime of the battery is almost halved. The other cases show the same result, with slightly different numbers. In any case, it is an understatement to say that the degradation heavily affects the lifetime of the battery.

TABLE II
COMPARING CASES

| Cost | ET | ET deg. | DC | DC deg. |
|---|---|---|---|---|
| $e^B$ | 6.8 | 6.8 | 7.0 | 7.0 |
| $p^{PV}$ | 25.4 | 24.9 | 0 | 0 |
| $\sum p^{imp}$ | 131,853 | 131,994 | 145,986 | 145,869 |
| $\sum p^{exp}$ | 402 | 358 | 0 | 0 |
| max. $p^{imp}$ | 35 | 35 | 35 | 35 |
| max. $p^{exp}$ | 10.0 | 8.0 | 0 | 0 |
| $\sum p^{ch}$ | 2,152 | 1,124 | 2,348 | 1,152 |
| $\sum p^{disch}$ | 1,942 | 1,014 | 2,119 | 1,040 |
| no. of cycles[a] | 317 | 165 | 334 | 164 |
| lifetime [y][b] | 6.3 | 12.1 | 6.0 | 12.2 |

[a]no. of cycles is here calculated in a simplified manner, by $\frac{\sum p^{disch}}{e^B}$
[b]lifetime is here calculated from the cycle lifetime of the battery, which is 2000 cycles at full discharge [5]

## V. Conclusion

The aim of this article was to investigate how battery degradation impacts the investment and operation of a community battery which performs multiple services. Optimisation models have been developed for energy-based and demand charge grid tariffs, with and without considering battery degradation.

When including degradation cost, the battery assesses whether or not the revenues from the service outweighs the degradation cost of the battery cycle. Under demand charges, the battery finds it profitable to do peak shaving. In the energy-based tariff cases, the battery gains value mainly through self-consumption and spot price arbitrage when the price is high, despite the degradation costs.

The lifetime of the battery is significantly shortened when not considering degradation, highlighting the need to include cyclic degradation in models that investigate the profitability in investment and operational problems with batteries. For both grid tariffs, the expected lifetime was shortened by approx. 6 years when not considering degradation.

Future work includes further development of the degradation model, case studies on LECs with different types of load profiles, and investigation of how the battery operation affects the distribution grid voltage.

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## NOMENCLATURE

**Parameters**

$\delta$ Cycle depth [%]
$\Delta\Phi(\delta_j)$ Size of cycle depth of segment j [%]
$\eta$ Battery efficiency
$C^B$ Investment cost of battery [NOK/kWh]
$C^{B,rep}$ Replacement cost of battery [NOK/kWh]
$C_j^{deg}$ Degradation cost for segment j
$C^{PV}$ Investment cost of PV [NOK/kWp]
$C_t^{spot}$ Electricity spot price in hour t [NOK/kWh]
$C_m^{tar,d}$ Demand charge grid tariff for month m [NOK/kW]
$C^{tar,e}$ Energy based grid tariff [NOK/kWh]
$CRF^B$ Capacity recovery factor battery
$CRF^{PV}$ Capacity recovery factor battery
$i$ Interest rate
$n^B$ Lifetime of battery [y]
$n^{PV}$ Lifetime of PV system [y]
$P_t^D$ Demand households in hour t [kWh/h]
$P^{exp,max}$ Grid export limit [kWh/h]
$P^{imp,max}$ Grid import limit [kWh/h]
$P^{PV,max}$ Maximum PV size [kWp]
$P_t^{PV}$ PV production in hour t [kWh/kWp]

**Indices**

$J$ Number of segments
$j$ degradation segment
$m$ month
$T$ Last hour of year [t]
$t$ hour
$y$ year

**Variables**

$\beta_t^{deg}$ Battery degradation cost in hour t [NOK]
$e^B$ Energy capacity of battery [kWh]
$p_{jt}^{ch,seg}$ Battery charging for segment j in hour t [kWh/h]
$p_t^{ch}$ Battery charging in hour t [kWh/h]
$p_{jt}^{dich,seg}$ Battery discharging for segment j in hour t [kWh/h]
$p_t^{disch}$ Battery discharging in hour t [kWh/h]
$p_t^{exp}$ Export to grid in hour t [kWh/h]
$p_t^{imp}$ Import from grid in hour t [kWh/h]
$p_m^{max}$ Maximum import from grid in month m [kWh/h]
$p_t^{PV,c}$ Curtailed energy in hour t [kWh/h]
$p^{PV}$ Size of PV system [kWp]
$soc_{jt}^{seg}$ Battery state of charge for segment j in hour t [kWh]
$soc_t$ Battery state of charge in hour t [kWh]

## APPENDIX

### A. Yearly plots

Fig. 11 shows the results from ET case.
Fig. 12 shows the results from ET deg. case.
Fig. 13 shows the results from DC case.
Fig. 14 shows the results from DC deg. case.

### B. Costs

Fig. 15 shows the yearly degradation cost for all cases.
Tab. III shows the resulting costs for all cases.

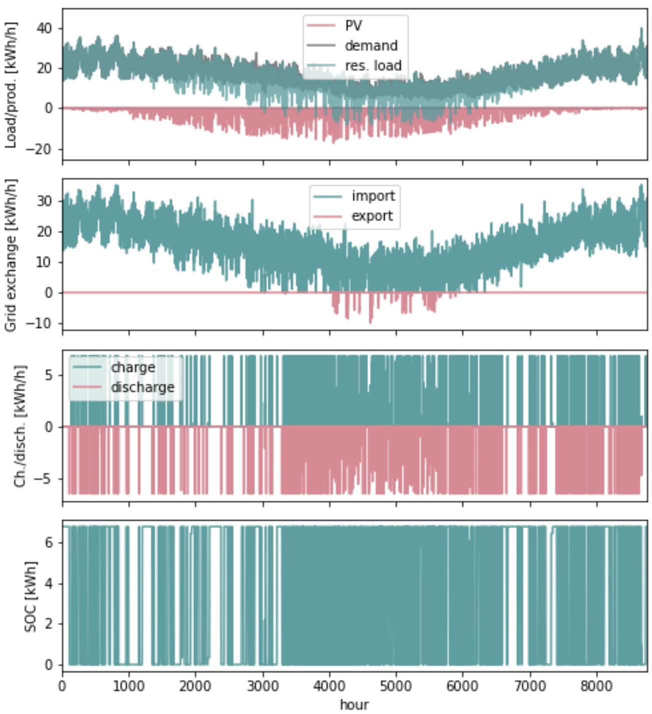


Fig. 11. ET case

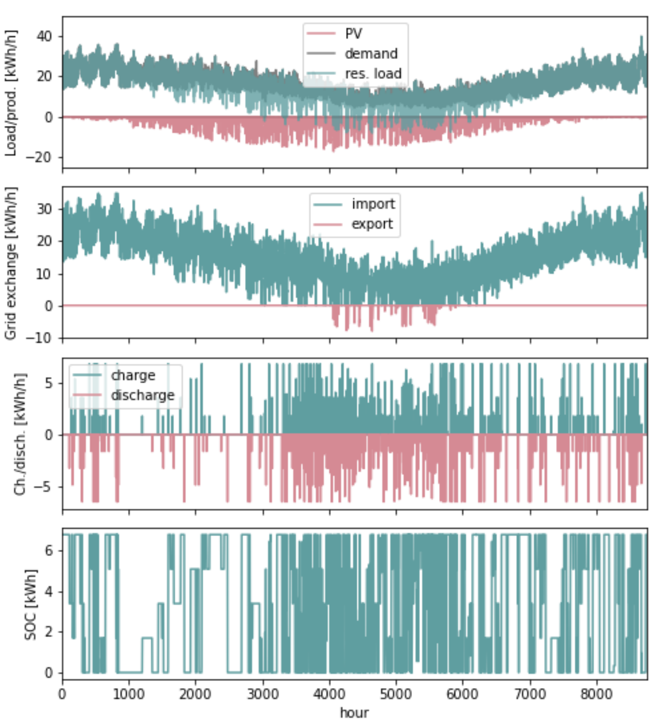


Fig. 12. ET deg. case

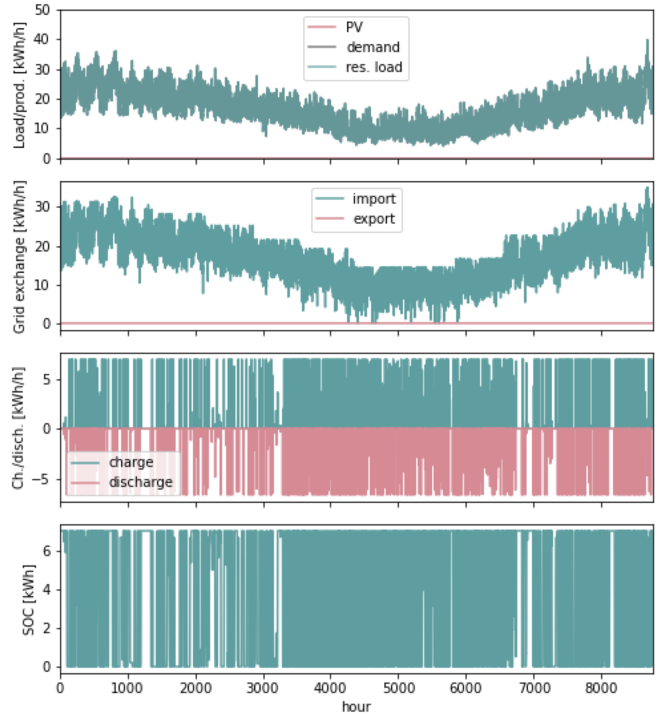


Fig. 13. DC case

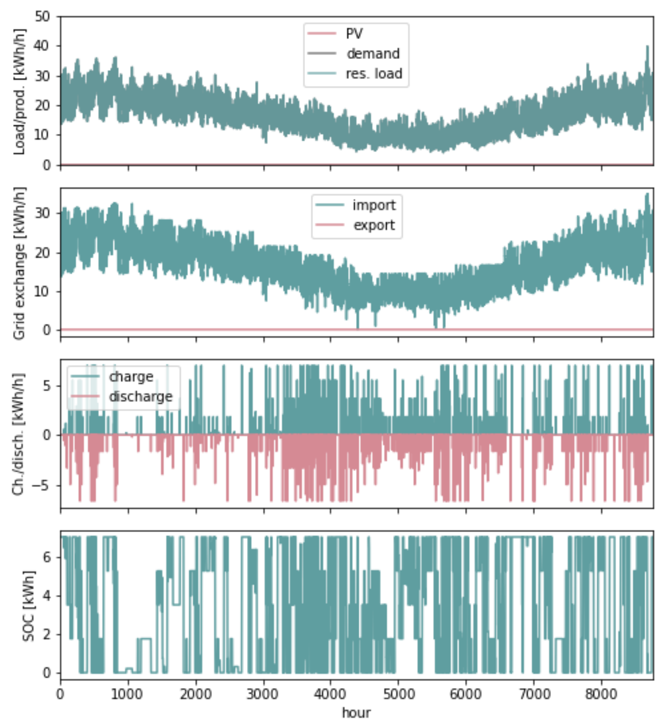


Fig. 14. DC deg. case

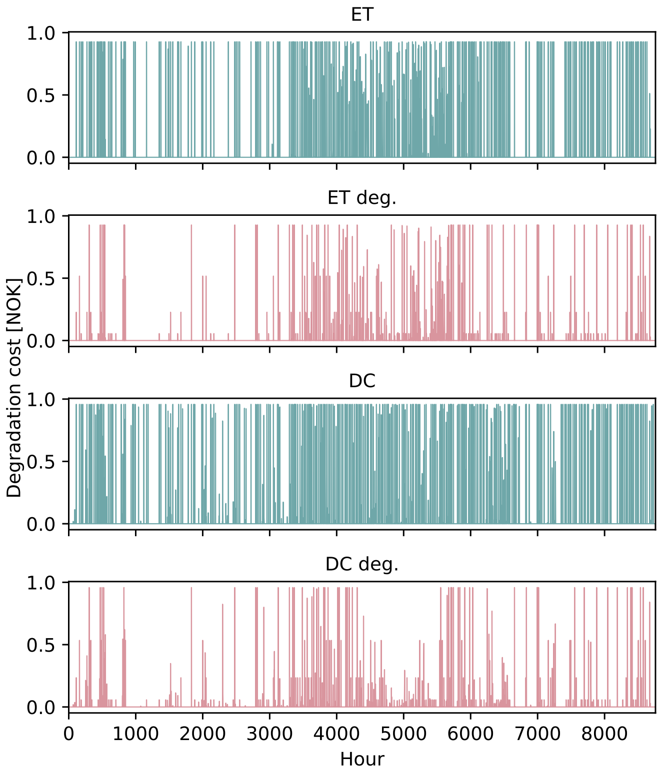


Fig. 15. Comparing degradation cost for cases

TABLE III
COMPARING CASES - COSTS [NOK]

| Cost | ET | ET deg. | DC | DC deg. |
|---|---|---|---|---|
| Ann. cost battery | 1,769 | 1,769 | 1,829 | 1,829 |
| Ann. cost PV | 13,346 | 13,083 | 0 | 0 |
| Energy cost | 129,281 | 129,551 | 119,150 | 119,198 |
| Demand cost | 0 | 0 | 17,654 | 17,654 |
| Degr. cost[a] | 278 | 114 | 302 | 109 |
| Objective function | 163,151 | 163,321 | 159,063 | 159,239 |

[a] The degradation cost is reported for all cases, but is only included in the objective function for cases ET deg. and DC deg.