Battery Degradation-aware Congestion Management in Local Flexibility Markets

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***Abstract*—Recently, distribution system operators (DSO) are facing increasing congestion management challenges in its grids due to increasing electricity demand peaks. Batteries are widely assumed to be a promising technology to deal with these challenges. However, DSOs are in many countries not allowed to buy or sell electricity, but must request flexibility through a future local flexibility market (LFM). This paper proposes a LFM architecture which allows the DSO to book flexibility from aggregators who control batteries on behalf of the asset owners, and activate flexibility when needed. This problem is formulated as a two-stage stochastic optimization program where the DSO books flexibility considering the expected cost of energy not served and cost of battery degradation when activated. A sensitivity analysis with respect to the projected battery prices and different values of lost load (VoLL) are carried out. The achieved results illustrate that the batteries are nowadays at affordable prices for flexibility provision. However, the *affordable battery price* where no curtailment occurs, is only achievable when prices reach below 200 €/kWh, depending on VoLL.**

***Index Terms*—Congestion management, battery degradation, local flexibility market, load uncertainty**

NOMENCLATURE

Indices and Sets

B/b	Set/index of batteries
J/j	Set/index of virtual battery segments
S/s	Set/index of scenarios
T/t	Set/index of time steps

Parameters

ρ_s	Probability of scenario s [%]
A_b^{ch}	Battery charging efficiency [%]
A_b^{dis}	Battery discharging efficiency [%]
$C^{book\uparrow}$	Cost for booking capacity [$\frac{€}{kWh}$]
C^{VOLG}	Value of lost generation [$\frac{€}{kWh}$]
C^{VOLL}	Value of lost load [$\frac{€}{kWh}$]
C_t^{DA}	Forecasted day-ahead spot price [$\frac{€}{kWh}$]
E_{bj}^{cap}	Energy capacity of segment j in battery b [kWh]
E_b^{cap}	Energy capacity of battery b [kWh]
L_{ts}^{load}	Substation load [kWh/h]
Q_b^{ch}	Maximum battery charging power [kW]
Q_b^{dis}	Maximum battery discharging power [kW]
X^{imp}	Substation import limit [kWh/h]

Variables

δ_{bt}	Battery binary variable
$\hat{\delta}_{bts}$	Second stage battery binary variable
$\hat{e}_{bts}$	Second stage battery state of charge [kWh/h]
$\hat{q}_{btsj}^{ch,seg}$	Second st. bat. segment j ch. power [kWh/h]
$\hat{q}_{btsj}^{dis,seg}$	Second st. bat. segment j disch. power [kWh/h]
$\hat{q}_{btsj}^{seg}$	Second st. bat. segment j SOC [kWh/h]
$\hat{q}_{bts}^{ch}$	Second stage battery charging power [kWh/h]
$\hat{q}_{bts}^{dis}$	Second stage battery discharging power [kWh/h]
$a_{ts}^{\uparrow}$	Activated upward flexibility [kWh/h]
e_{bt}	Battery state of charge [kWh/h]
q_{bt}^{ch}	Battery charging power [kWh/h]
q_{bt}^{dis}	Battery discharging power [kWh/h]
$r^{\uparrow}$	Booked upward capacity [kWh]
x_{ts}^{VoLG}	Curtailed generation [kWh/h]
x_{ts}^{VoLL}	Curtailed load [kWh/h]

I. INTRODUCTION

Network reinforcements have traditionally been the main approach when the distribution grid has faced congestion issues. Recent developments have given local flexibility markets (LFM) increasing importance as the shares of photovoltaics (PV) and distributed energy resources (DER) such as electric energy storage (EES) are rising. Grid congestions due to increasing demand is occuring more and more in the distribution system, for example in Norway where the regulator estimates an alarming 13 billion € to be spent in the grid over the next 10 years due to an ever-increasing electrification of the energy demand [1]. A share of these costs can be mitigated by using local flexibility to support the grid in terms of congestion management, as flexible devices such as EES can be utilized to shave peak loads. A joint statement from the DSOs on the importance of EES can be found in [2].

The incorporation of flexibility options into distribution grid reinforcement planning is becoming more interesting as the availability, price and reliability of flexibility is improved [3]. For EES to deliver congestion management services, there are two options. A) The DSO buys and controls batteries centrally, or B) has to book and activate flexibility through a local flexibility market (LFM) where asset owners are paid to reserve battery capacity in order to deliver flexibility in the scenarios where it is needed. The first option benefits from the DSO having full control of the assets, ensuring reliable supply of flexibility at a low price. However, according to the European Commission: *"Distribution system operators shall not be allowed to own, develop, manage or operate energy storage facilities."* [4], which discourages research in this direction. Many other entry barriers for energy storage are described in [5]. Therefore, the second option has received more attention in recent literature. A market solution for DSO congestion management is described in [6], where the aggregator is acting on behalf of asset owners and receives information from the DSO on which flexibility is needed. [7] formulated a multi-market bidding strategy for the aggregator with a DER portfolio, but focused on frequency services rather than congestion management.

EV aggregators are used in [8] to deal with congestion management in a day-ahead flexibility market framework. Similarly, an optimization problem for meeting DSO requests in LFM with EES and other DER is described in [9], where the aggregator minimizes the cost of scheduling flexible resources in a deterministic fashion. However, the uncertainty in flexibility requests remains unaddressed in these studies.

For the DSO, flexibility reliability is crucial as it has to be there when needed. The day-ahead procurement (or booking) of flexibility is therefore vital because the net load realization is uncertain [10].

A drawback of many battery flexibility related studies is the lack of consideration of battery degradation in the optimization program. Some of the mentioned DER scheduling related studies are delivering services using EES, where the cost of delivering the service is higher than the value gained. This issue was raised by [11], who considered a battery life-cycle based degradation model in order to determine the real cost of using the EES when determining optimal bids in day-ahead and reserve markets. Similarly, [12] developed a rainflow-based cycle degradation model which splits the EES into virtual segments, adding a piece-wise linearized increasing cost to use each of the segments. Calendar ageing in lithium-ion batteries are also of significance but are of less importance in short term market perspectives [13].

This paper is inspired by [14], where battery participation in energy and spinning reserve markets is investigated under a similar battery degradation approach. We perform a similar analysis, but focus on the DSO and aggregator cooperation to use batteries in distribution grids to deliver congestion management services using local flexibility markets under uncertainty in demand. The contributions are as follows:

- We describe a day-ahead LFM as a two-stage stochastic program where the DSO can book flexibility and activate it given the realization of the uncertainty,
- We combine a cycle-ageing based battery degradation model from [12] and [11] and find the optimal flexibility booking strategy of the DSO under different values of projected battery prices and VOLL.

The rest of the paper is organized as follows. Section II describes the role of the aggregator, the day-ahead LFM booking problem framework and li-ion based battery degradation. Further, the case study is described in Section IV followed by the results in Section V. Finally, concluding remarks and future work are stated in Section VI.

II. Market description

The use of batteries for flexibility must be facilitated through a LFM. However, to the authors knowledge, a general LFM that facilitates local flexibility trade does not exist in Europe with the exception of pilot projects. The novelty of this paper is revolved around the importance of battery degradation-aware models in LFM and not revolved around market design, but we still provide a description of the envisioned LFM to clarify the assumptions that are made in this paper in the following section.

A. The role of the aggregator

In order for the DSO, to book flexibility, there must be some flexibility service providers who have submitted offers to the market. The flexibility service providers are asset owners or acting on behalf of asset owners (in our case: aggregators), who control the flexibility assets decisions. The aggregator manages a portfolio of batteries on behalf of the battery owners. The aggregator's objective is to minimize the cost of flexibility provision. The presented case study only considers congestions where the load on the substation surpasses the rated power (also known as upward active power congestions) in this paper. Upward/downward active power flexibility can be defined as a service where the provider increases/decreases its active power injection to the grid. We use similar terminology as in other balancing markets to avoid confusion.

B. The local flexibility market

Following the market design from [15], the aggregator acts as a market player which operates assets on behalf of end-users in order to deliver services to the DSO. We assume that the LFM shares properties with the day-ahead market as well as the balancing markets, meaning that the presented formulation considers a 24 hour time horizon with hourly activation. The market is cleared 12 hours before the first hour of the time horizon, meaning that the uncertainty exists from the very first hour of the horizon. The DSO can forecast a need for flexibility based on some forecasted parameters (such as temperature, irradiation etc), and uses historical data with similar properties to create flexibility requirement scenarios for the next day. To assure that the flexibility is available when needed, the flexibility must be booked in the LFM. During the real-time operation, DSO, upon need, asks the aggregator to activate a share of the day-ahead booked flexibility. In this approach, the aggregator only considers the day-ahead market in a simplified manner by assuming deterministic day-ahead prices (perfect foresight). In a realistic market, uncertainty in prices should be considered to assure optimal coordination between the LFM and the day-ahead market. However, this is not the focus of this paper.

An important feature added to the market design is the batteries need to reserve the total amount of energy booked by the DSO for reliability reasons. This feature is considered as batteries are of relatively low energy volume and therefore have a chance of not having energy available when requested by the DSO. This way, the DSO can be certain that the booked energy is available for the time horizon. Reserving energy instead of capacity is slightly different to frequency reserve markets, but are added to ensure reliability for the DSO.

The DSO flexibility booking problem as well as the market time horizon is shown in fig. 1.

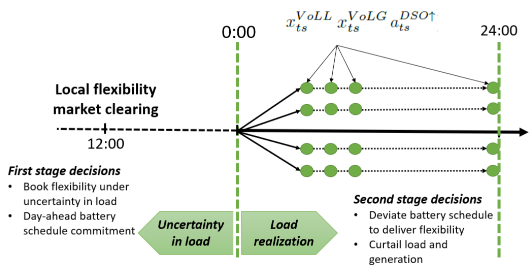

Fig. 1. DSO flexibility booking problem. The first stage variables represent the day-ahead decision of booking flexibility, whereas the second stage variables are the activation strategy under uncertainty.

C. Battery cycle degradation

A promising battery technology for flexibility services are lithium-ion batteries with nickel, manganese and cobalt. Degradation of such batteries are dominated by the depth of each cycle, which is nonlinear. To model the degradation cost of the battery, this paper relies on the rainflow-based model presented in [12]. This model splits the battery into virtual battery segments, and allocates a cost to using each segment based on cycle depth. In essence, a deep cycle is costlier than a shallow cycle. The loss of cycle life as a function of cycle depth is presented in fig. 2. The figure shows that whereas a full cycle costs around to 0.05 % of the total available cycles (the battery has 2000 full equivalent cycles in its lifetime). A half cycle costs significantly less (0.013 %) of the total cycle life, meaning that a lower cost should be allocated.

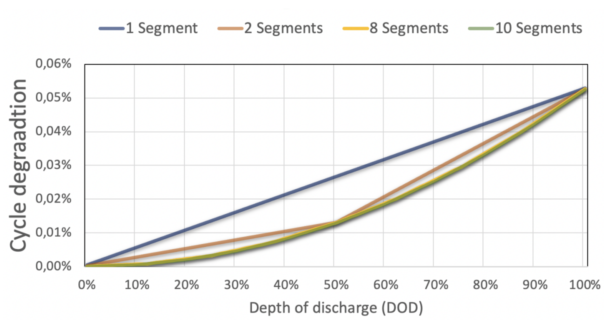

Fig. 2. Percentage of battery degradation costs as a function of cycle depth.

III. Model formulation

The DSO aims to minimize its total costs, including expected costs of booking and activating flexibility as well as the expected cost of curtailed load and generation. In addition, batteries can react to the DA price. Battery degradation costs are also considered. In essence, the DSO finds the optimal procured flexibility and optimal state of charge and charging decisions in order to deliver flexibility $a_{ts}^{\uparrow}$.

The objective is given by (1). The first term expresses the cost of booking flexibility. The second term is related to the purchase and selling of electricity, whereas the second term minimizes the cost of degradation. These two terms are the costs related to the first-stage decisions, where commitments to the day-ahead market (spot and LFM) are done. The second-stage start with term 3 which expresses the degradation costs which are allocated by the segment battery discharge variable $\hat{q}_{btsj}^{dis}$ and the degradation cost C_{bj}^{deg} which is drawn from fig. 2. The fourth term represents the initial SOC of the batteries, ensuring that the battery energy at the beginning of the planning horizon is paid for, using the price of the first hour of the planning horizon. This term is of a pragmatic nature to assure that the batteries in the model start with 100 % SOC and end with 0 % SOC without paying for it. The freedom to end with any SOC level is necessary to make sure that the program is feasible in all scenarios. Furthermore, the fifth term consists of the costs of deviating from the charging plan in each scenario. Note that we assume that the costs for energy are not intraday prices, but day-ahead prices as the need for deviation is because of activation of flexibility. Finally, the cost of curtailing load and generation are shown in the last term.

$$\begin{aligned}\min \quad & r^{\uparrow} \cdot C^{book\uparrow} + \sum_b \sum_t (q_{bt}^{ch} - q_{bt}^{dis}) C_t^{DA} \\ & + \sum_b \sum_s \rho_s \sum_t \sum_j \hat{q}_{btsj}^{dis} C_{bj}^{deg} + \sum_b \sum_s C_0^{DA} \cdot \hat{e}_{b0s}^{init} \\ & + \sum_b \sum_t \sum_s \rho_s \left[C_t^{DA} (\hat{q}_{bts}^{ch} - \hat{q}_{bts}^{dis}) \right] \\ & + \sum_t \sum_s \left[\rho_s (C^{VoLL} x_{ts}^{VoLL} + C^{VoLG} x_{ts}^{VoLG}) \right] \end{aligned} \tag{1}$$

The planning problem for flexibility booking is formulated as a two-stage stochastic optimization program, where the first stage decisions are the charging decisions of all batteries and booking of flexibility. The first stage battery decisions are then submitted to the market as a baseline. To deliver flexibility, the deviation from the baseline $\sum_b \hat{q}_{bts}^{dis}$ in the second stage must equal the difference in charging in scenario s and the first stage (baseline) commitment $\sum_b q_{bt}^{dis}$, corresponding to $a_{ts}^{\uparrow}$ as shown in eq. (2).

$$\forall ts \quad X^{imp} + a_{ts}^{\uparrow} + x_{ts}^{VoLL} \geq L_{ts} \tag{2}$$

Further, the energy balance at the substation level is shown in eq. (3a). This equation shows that if the load L_{ts} is higher than the import limit X^{imp}, load must either be curtailed or flexibility must be activated.

$$\forall ts \quad X^{imp} + x_{ts}^{VoLL} \geq L_{ts} + \sum_b (\hat{q}_{bts}^{ch} - \hat{q}_{bts}^{dis}) \tag{3a}$$

$$\forall s \quad r^{\uparrow} \geq \sum_b \sum_t (\hat{q}_{bts}^{dis} - q_{bt}^{dis}) \tag{3b}$$

$$\forall s \quad r^{\uparrow} \geq \sum_t a_{ts}^{\uparrow} \tag{3c}$$

$$\sum_b e_{b0} \geq r^{\uparrow} \tag{3d}$$

$$\forall bs \quad \sum_b \hat{e}_{b0s} \geq r^{\uparrow} \tag{3e}$$

The deviation from the first stage plan cannot exceed the procured flexibility (3b). Similarly, the activation variable $a_{ts}^{\uparrow}$ cannot exceed the booked amount in each scenario as shown in (3c). To guarantee that the booked flexibility is available in the battery for the entire planning horizon, the booked energy must be available in all scenarios at the beginning of the planning horizon as suggested in (3d) and (3e).

First stage battery constraints are shown below. SOC evolution is shown in (4a), where the charging and discharging efficiency is given by A_b^{ch}, A_b^{dis}, respectively. Further, the maximum charging and discharging constraints are given by (4b) and (4c), respectively. The state of charge limits are restricted in (4d).

$$\forall bt \quad e_{bt} - e_{b(t-1)} = \Delta T(q_{bt}^{ch} A_b^{ch} - \frac{q_{bt}^{dis}}{A_b^{dis}}) \tag{4a}$$

$$\forall bt \quad q_{bt}^{ch} \leq Q_b^{ch} \cdot \delta_{bt} \tag{4b}$$

$$\forall bt \quad q_{bt}^{dis} \leq Q_b^{dis} \cdot (1 - \delta_{bt}) \tag{4c}$$

$$\forall bt \quad 0 \leq e_{bt} \leq E_b^{cap} \tag{4d}$$

Battery constraints for second stage flexibility delivery still apply as shown in the following equations. eq. (5) gives the 2nd stage state of charge evolution. A second stage SOC equation is needed due to assure correct operation of the batteries in the second stage, which is the actual operation of batteries in each scenario s. Also, this equation has segmented variables which are essential for including the piecewise linearized battery degradation cost.

$$\forall btsj \quad \hat{e}_{btsj} - \hat{e}_{b(t-1)sj} = \Delta T(\hat{q}_{btsj}^{ch} A_b^{ch} - \frac{\hat{q}_{btsj}^{dis,seg}}{A_b^{dis}}) \tag{5}$$

Link between segmented battery variables and non-segmented battery variables are given below in (6a)-(6f), as well as the second stage charging and state of charge limits.

$$\forall bts \quad \sum_j \hat{e}_{btsj} = \hat{e}_{bts} \tag{6a}$$

$$\forall bts \quad \sum_j \hat{q}_{btsj}^{ch,seg} = \hat{q}_{bts}^{ch} \tag{6b}$$

$$\forall bts \quad \sum_j \hat{q}_{btsj}^{dis} = \hat{q}_{bts}^{dis} \tag{6c}$$

$$\forall bts \quad 0 \leq \sum_j \hat{e}_{btsj}^{seg} \leq E_b^{cap} \tag{6d}$$

$$\forall bts \quad \hat{q}_{bts}^{ch} \leq Q_b^{ch} \cdot \hat{\delta}_{bts} \tag{6e}$$

$$\forall bts \quad \hat{q}_{bts}^{dis} \leq Q_b^{dis} \cdot (1 - \hat{\delta}_{bts}) \tag{6f}$$

IV. Case study

The model formulation is tested on a stylized 3-bus system with a HV/MV transformer with two MV/LV transformers. Each substation has 47 end-users and we only consider load balance and congestions on substation level (no power-flow equation are considered). Real load data from end-users in Norway are used to simulate the load in the LV grid. The case study is visualized in fig. 3.

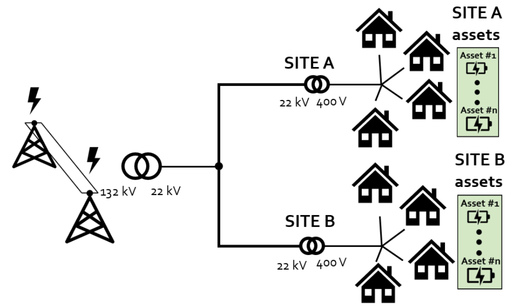

Fig. 3. Case study overview

To see the impact of battery degradation in the flexibility booking strategy, we run two case studies.

1) Market setting where DSO must book flexibility in the LFM. DSO pays a price for booking flexibility, and activations costs based on degradation cost. This is based on the model described in section III.

2) Same approach as in 1) but without degradation costs in the objective function. This translates to having no battery degradation costs.

We analyze the impact of two factors; battery cost spanning from 100 - 450 €/kWh[1] and value of lost load (from 0 - 5 €/kWh). The present and projected battery prices from [16], [17] and [18] as well as the VoLL from [19] were used. Because VoLL depends on customer type, we use 1-6 €/kWh.

By performing a sensitivity analysis with respect to these two parameters, we analyze how the DSO's optimal flexibility booking problem changes depending on the investment cost of batteries and what VoLL has to be paid.

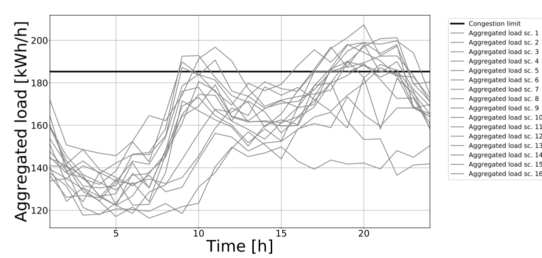

Fig. 4. Load in all scenarios for flexibility requests for site A.

The scenarios for the substation level load are generated using real-life load data from 94 end-users in Norway [20], following the presented steps:

[1]We consider a P/E factor of 1.

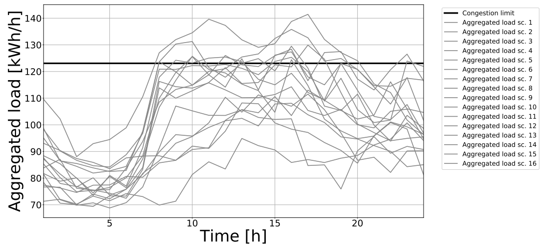

Fig. 5. Load in all scenarios for flexibility requests for site B.

1) Choose a temperature range[2] (-7 to -12 celsius was used). This resulted in this case in 16 scenarios.
2) We select the days which had an average temperature between these two limits. For simplicity we do not include weekends.
3) Extract load data from each consumer from the relevant days, and aggregate them to simulate the load behind the two MV/LV transformer.
4) We allocate the aggregated loads of each substation in our problem.

By following this approach, the DSO can generate scenarios based on the forecasted temperature. The load forecasts for site A and B are shown in fig. 4 and fig. 5, respectively. The complete data of the case study is found in table I.

TABLE I
DATA OF THE CASE STUDY.

Site	Site limit	Peak load	Worst scen. overloading	Battery cap. / rated power	One-way efficiency
A	185 kW	207 kW	94 kWh	50 kW(h)	97 %
				30 kW(h)	96 %
				20 kW(h)	95 %
				10 kW(h)	94 %
				10 kW(h)	93 %
B	123 kW	141 kW	125 kWh	50 kW(h)	97 %
				50 kW(h)	96 %
				20 kW(h)	95 %
				10 kW(h)	94 %
				10 kW(h)	93 %

Finally, price data for day-ahead prices C_t^{DA} were taken from NordPool website. Flexibility booking prices $C^{book\uparrow}$ do not exist and were therefore assumed to be 150 % of the average DA price to compensate for lack of arbitrage possibilities.

V. Results and Discussion

A. DSO flexibility booking under battery degradation

As shown in fig. 6, the total cost of the DSO increases with increasing VoLL. In the case where the DSO is not economically responsible for load curtailment, the costs are 0 € as no flexibility must be procured. When VoLL and battery prices increase, the total costs for the DSO naturally increases. It is noteworthy that the relative cost increase is significantly higher at increasing values of VoLL, whereas the cost expectation is more compact for lower values of VoLL.

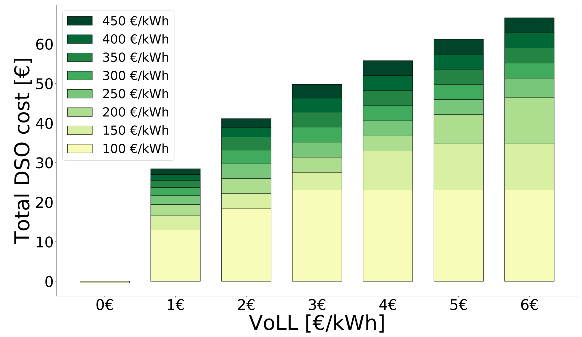

Fig. 6. Costs for different VoLL and projected battery prices.

One of the important metrics for the DSO is the expected energy not served (EENS). From fig. 7, it is shown how the EENS changes with projected battery prices under different levels of VoLL. Note that zero EENS is only expected if VoLL levels are 3 €/kWh or higher, even for battery prices as low as 100 €/kWh. Altohugh an EENS of 5-15 kWh might seem very low, this is due to many of the scenarios not resulting in any overloading as seen in fig. 4 and fig. 5.

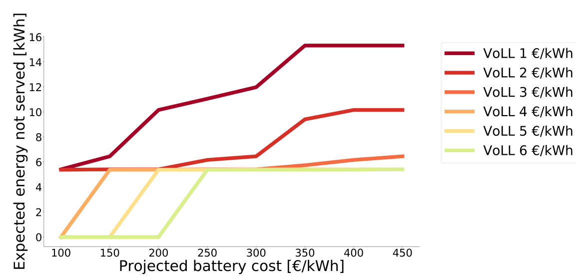

Fig. 7. EENS under different projected battery prices and VoLL.

B. DSO flexibility booking without battery degradation

Not considering battery degradation costs virtually means that batteries are used similarly in all cases of battery prices, as the objective in each iteration with different battery prices are equal. The objective of each instance is the same as shown by the green color in fig. 8. The objective is negative, meaning that there is revenue from arbitrage which surpasses the cost of booking flexibility. The battery degradation costs are added post-optimization and are shown as the red bars. Since the degradation cost is related to the projected battery price, the costs increase with increased battery prices. After degradation costs are added (post-optimization), the total DSO costs are much higher than when degradation costs are part of the optimization as shown in fig. 6. When considered, battery degradation costs increase the costs from 70 € - 310 € when considered. These results highlight the need to model the degradation cost correctly in the decision making process.

[2]Load is residential areas is heavily dominated by temperature due to a high share of electric heating.

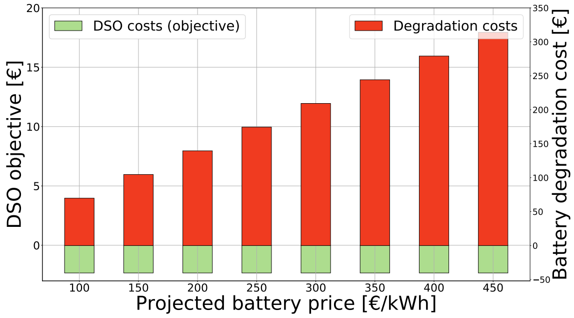

Fig. 8. Costs for different projected battery prices. Post-processed degradation costs are shown as red bars. Note that the left axis has the costs (which are revenues) has a different scale than the right axis (degradation costs).

C. Discussion

The results show that the strategy of the DSO in the future LFM is sensitive to the cost of the available flexibility resources, as well as the VoLL, which is relevant in a real future market for distribution grid flexibility. As battery prices decrease, avoiding curtailment of load is more and more likely as flexibility services turn cheaper. Still, it is important to acknowledge the realistic degradation cost of using batteries for flexibility, and they should only be used if the degradation cost is lower than the avoided curtailment cost.

In general, the results show that VoLL has the largest impact rather than projected battery price in terms of DSO flexibility booking strategy. The results imply that if the LFM can exist, it will provide value from day one as the services that can be provided are already valuable even with relatively high projected battery prices.

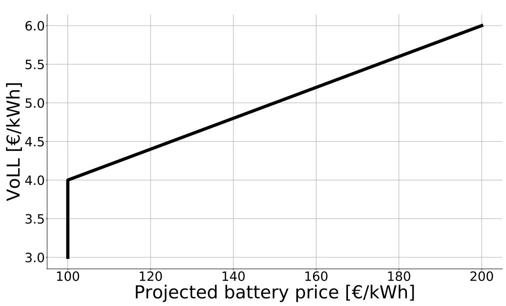

Fig. 9. *Affordable battery prices* with different levels of VoLL with 0 EENS.

At the point where EENS is zero, the *affordable battery price* at different levels of VoLL can be found. This is portrayed in fig. 9. The results show that only when VoLL is at 2 €/kWh or higher, there will be no curtailment in the DSO strategy. In addition, any VoLL value above 4 €/kWh will result in no curtailment as it is too expensive. In the span between 2-4 €/kWh, the battery price is decisive for reaching zero EENS.

Using this approach, any DSO can analyse if its grid could benefit from batteries in order to avoid curtailment of load, depending on the relevant VoLL in the system and the projected battery price available. For example, battery costs are expected to reach roughly 200 €/kWh in 2030, which would result in no curtailment in this particular case study if VoLL is 6 €/kWh or higher.

VI. Conclusion

This paper analyzed the impact of projected battery prices and value of lost load on the DSO flexibility booking strategy under uncertainty in demand using a LFM approach. By combining advanced cycle-degradation based battery models and day-ahead flexibility booking problem for congestion management using a two-stage stochastic approach, the results showed that the use of LFM and DSO flexibility booking is valuable also for relatively costly batteries. *Affordable battery prices* where EENS is zero is projected to be 100-200 €/kWh depending on VoLL in the relevant grid. In general, using batteries to avoid curtailment is profitable already at present day battery investment costs, but strictly depends on the VoLL.

Furthermore, solving the same problem with and without considering degradation costs showed how important it is to account for the realistic cost of using the battery.

Further work should investigate LFM with different time horizons, preferably also with real-time operation where the uncertainty is not necessarily covering the possible realizations like we have assumed in this paper. In addition, the paper could be extended to also include an AC-PF formulation to investigate other services such as voltage control and losses.

VII. Acknowledgements

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