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A local flexibility market mechanism with capacity limitation services

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Abstract

Local flexibility markets have a substantial potential to unlock the flexibility of distributed energy resources in the distribution level. Capacity limitation services have been perceived as one of the most appealing products to be traded in these markets. This work argues why classical market-clearing and pricing mechanisms such as *pay-as-bid*, *uniform pricing* and *Vickrey-Clarke-Groves* (VCG) are not compatible with a market that trades capacity limitations. As a solution, we propose a local flexibility market mechanism which is built upon an adapted VCG-based auction. The mechanism achieves a trade-off among various desirable economic properties, including budget-balancedness, incentive-compatibility and stability. The suitability of the proposed mechanism is illustrated using a case study which is based on a real medium voltage feeder, located on the Danish island of Bornholm. Results show that aggregators and the distribution system operator benefit from the trade of capacity limitation services. We eventually conclude by providing a set of policy recommendations for the real-life operation of such a market.

Keywords: Auction design; capacity limitation; congestion management; distributed energy resources; distribution networks; local flexibility market

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Acronyms

CLS capacity limitation service

DER distributed energy resource

DN distribution network

DSO distribution system operator

EV electric vehicle

LFM local flexibility market

PAB pay-as-bid

SOC state of charge

TSO transmission system operator

UP uniform pricing

VCG Vickrey-Clarke-Groves

VOLL value of lost load

1. Introduction

Due to the intermittency and uncertainty of the ever-increasing shares of renewable power generation, finding additional sources of flexibility is a prerequisite of phasing out carbon-intensive power generation and achieving the decarbonization of the energy sector [1]. Aggregators of large portfolios of small-scale distributed energy resources (DERs) have in recent years started to participate in energy markets [2] by providing flexibility through the control and optimization of such resources [3]. The coordinated control of DERs, which are primarily located in distribution networks (DNs), leads to significantly higher load coincidence factors [4]. Consequently, some form of congestion management [5] and coordination with the transmission system operator (TSO) is needed [6, 7], to enable the efficient use of available DER flexibility [8].

European energy regulators have recently recognized four mechanisms for enabling access to flexibility in the DN [9] including: a *rules-based approach*, *network tariffs*, *connection agreements*, and *market-based procurement*. Out of those mechanisms, local flexibility markets (LFMs) have gained particular attention in recent years, as they allow for marked-based flexibility utilization and promote competition. Further, they are in line with European Network of Transmission

System Operators for Electricity (ENTSO-E) guidelines [10], which state that DERs should be able to sell services where it is most profitable for them. Therefore, LFMs seem to be the most promising flexibility-driven concept for Europe, and the EU recommends that distribution system operators (DSOs) procure their necessary flexibility through market-based solutions [11]. LFMs are envisioned to operate in parallel to the wholesale energy markets, and aggregators and DSOs will be able to trade flexibility services, as illustrated in Figure 1.

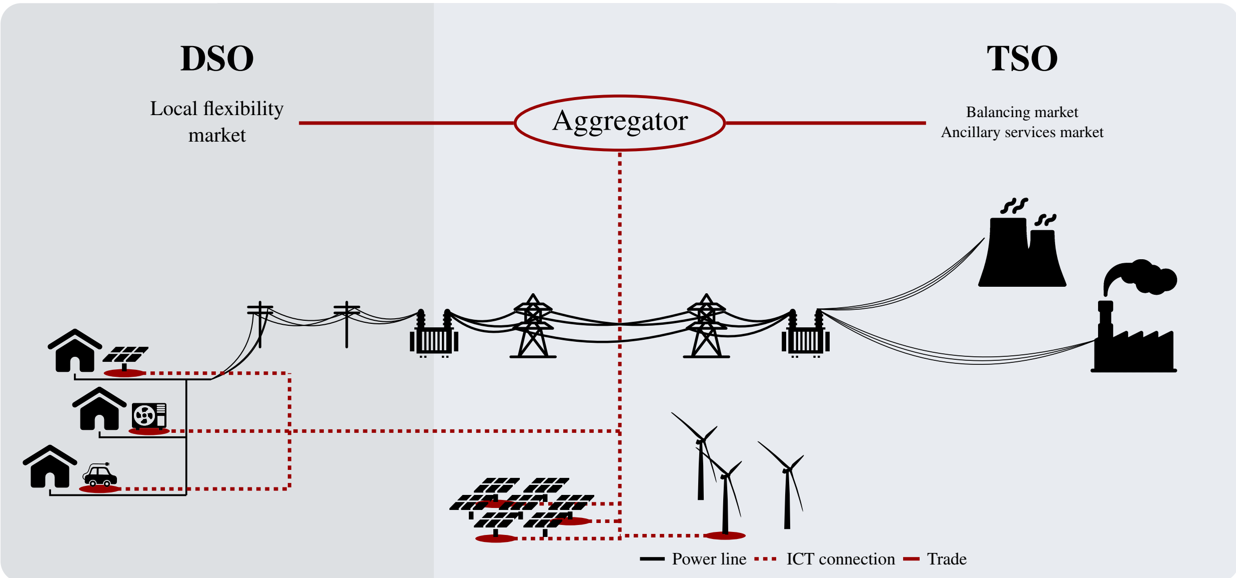

Figure 1: Overview of an aggregator's role in the power system (adapted from [12]).

In general, the proposed flexibility services for DNs can be split in two distinct categories: *baseline services* and *capacity limitation services (CLSs)*. Figure 2 distinguishes these two services. Assume that the DSO must keep the consumption of an aggregator below the limit of a transformer. CLSs (Figure 2 (a)) define a total power cap for an aggregator between time steps t_{start} and t_{end}. In contrast, baseline services (Figure 2 (b)) define a temporary power deviation from a reference power profile called *baseline*, by a specified amount of load reduction. Baseline services have the benefit of requiring a relatively simple framework for trading flexibility, in a way that is analogous to the balancing markets (i.e., deviations from agreed-upon schedules).

However, there are various shortcomings associated with the use of baseline services in DNs.

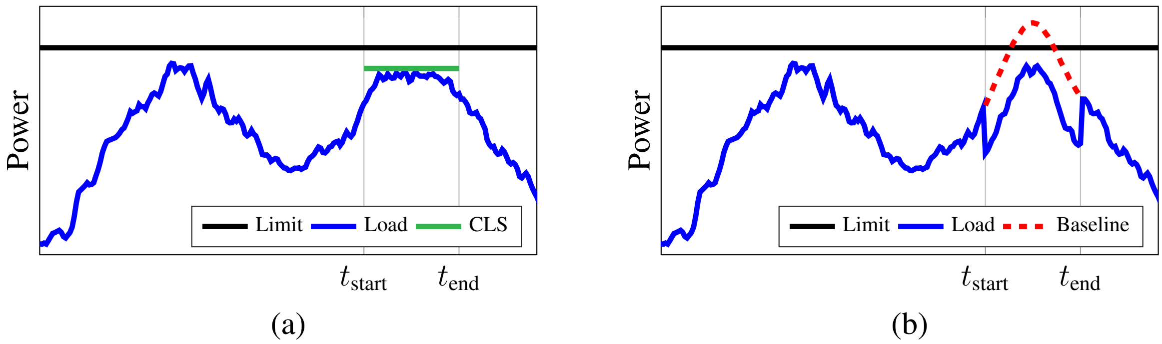

Figure 2: Sketch of a CLS (a) and a baseline service (b).

In our previous work [12], we present four requirements that services in an LFM need to fulfill. First, flexibility services must be simple and transparent. Second, services should be designed such that aggregators with relatively small portfolios can contribute to them. Third, it must be impossible to manipulate service delivery, i.e., to present artificially inflated flexibility provision. Fourth, flexibility services should allow aggregators to control their portfolios continuously, and flexibility services should therefore not be based on the assumption of "natural behavior" like dumb charging of electric vehicles (EVs). We then argue that none of the available methodologies for the establishment of baselines in flexibility markets fulfills all of the four requirements at once. Finally, baseline services cannot handle well the operational problems caused by the unpredictable load behavior of DERs, which participate in the wholesale energy markets. Due to these findings, in this paper we only consider the trade of CLSs in LFMs.

A potential market-clearing mechanism of an LFM with baseline services could be designed in a similar fashion to the existing wholesale market [13, 14], with the aggregators placing discrete offers of price and amount of load reduction [15]. In contrast, designing an efficient and fair market-clearing mechanism to trade CLSs is more complicated, as the same capacity limitations of different aggregators are not necessarily equivalent, in the way a load reduction due to a baseline service of say 100 kW would be. Several academic works have already considered LFMs for CLSs. For example, [16–18] analyze such services from an aggregator's perspective. Reference

[16] focuses on the consumer optimization problem under the assumption of a capacity limitation on their meter, and analyzes the corresponding pricing for customers and aggregators. References [17] and [18] analyze the costs that aggregators incur when offering CLSs under uncertainty. In addition, [19] analyzes experimental results of flexibility service provision, and proposes a method to quantify the financial benefit that CLSs bring to the DSO.

Potential market-clearing mechanisms for LFMs trading CLSs have so far received little attention. References [17] and [18] do not specify a market-clearing mechanism. Reference [18] proposes a pay-as-bid (PAB) mechanism but does not investigate the resulting market incentives that such a mechanism sets. Reference [20] proposes a hierarchical market structure for CLSs, prioritizing services for the DSO over system services, but without considering a market-clearing mechanism. References [21] and [22] suggest a market framework where aggregators acquire network capacity from the DSO incrementally. While such approaches might be relatively easy to implement, they may set wrong incentives for the DSOs, who are no longer encouraged to provide adequate network capacity.

This work investigates at which cost aggregators are able to offer CLSs (deriving offer curves), and how these can reduce the network operational cost of the DSO (deriving cost curve). Afterwards, a detailed analysis of different market-clearing mechanisms is carried out, namely *PAB*, *uniform pricing (UP)* and *Vickrey-Clarke-Groves (VCG)*. To the best of our knowledge, such a study has never been carried out before. Given the resulting offer and cost curves, the market participants' incentives under different clearing mechanisms are investigated. We find out that PAB and UP do not necessarily lead to efficient market outcomes, and we show that under VCG the market results in a financial deficit. Therefore, the use of a VCG-based clearing mechanism is proposed, which we refer to as *uni-sided VCG*. This mechanism achieves budget-balancendness by compromising incentive-compatibility on the DSO side only, but sets all desirable incentives for aggregators.

In the rest of the paper, section 2 introduces the envisioned market framework and provides a

CLS definition. Section 3 analyzes the cost structure of such services both for aggregators who offer CLS and the DSO who requests them. The results are then translated into CLS offer and cost curves, which are used to clear the market. In section 4, different market-clearing mechanisms and their economic properties are evaluated in light of the market participants' cost structures. Section 5 evaluates the proposed mechanisms using a case study. Finally, section 6 concludes the paper, and provides a set of policy recommendations.

2. Market Framework and Service Definition

This section provides an overview of how an LFM would work in practice. First, subsection 2.1 summarizes the most important assumptions of this work. Subsection 2.2 presents a sequence diagram of the envisioned setup, detailing the interactions of the involved actors. Next, subsection 2.3 discusses the main required functionalities by aggregators, DSOs and the market platform. Finally, subsection 2.4 provides the CLS definition that will be considered throughout the remainder of the paper.

2.1. Preliminary assumptions

A series of preliminary assumptions and requirements have been made, for the LFM framework to work under real-life conditions. This subsection summarizes the most important ones.

Smart meter infrastructure

A smart meter infrastructure must be in place, so that DSOs can assess the state of the network using historical values.

Flexibility registry

Aggregators need to register their flexible assets on some form of flexibility registry. This will allow DSOs and the LFM platform to retrieve the necessary information for placing service requests.

DSO regulatory framework

Under current regulatory frameworks DSOs are usually not sufficiently incentivized to invest in advanced network operational solutions, such as flexibility acquisition, as doing so would increase their operational expenditure in the short run. A change of the regulatory framework is needed, such that long-term cost effectiveness of network operation is incentivized.

LFM lead time

The investigated LFM trades scheduled services with relatively long lead times, so that these services are aligned with the planning procedures of DSOs.

2.2. Sequence diagram of a local flexibility market

Figure 3 shows a sequence diagram of the LFM with the interactions of the four involved actors, namely the DSO, the market platform, aggregators and the customer-owned DERs. Aggregators continuously control and observe the DERs in their portfolio. An accurate estimation of their available flexibility is crucial to offer services in the LFM in a reliable manner [23].

In order to operate the DN efficiently, DSOs regularly estimate the possible load flows on their networks for upcoming periods. When a potential congestion is foreseen, one option is to acquire a flexibility service from the LFM. DSOs need to specify the parameters of the service that would be beneficial for the operation of the network. For example, it could be a CLS from 17.00 to 20.00 every weekday of a given month, and for a particular primary substation. Next, DSOs must estimate the cost of operating their DN with different acquired services, and thereby establish a cost curve. DSOs forward the service parameters and the cost curve to the market platform and initiate an auction. The market platform notifies all relevant aggregators who can offer the service and sends them the service parameters. All relevant aggregators evaluate the DSO's request and provide the market platform with their offer curves, indicating the minimum payment they are willing to accept for each amount of capacity limitation.

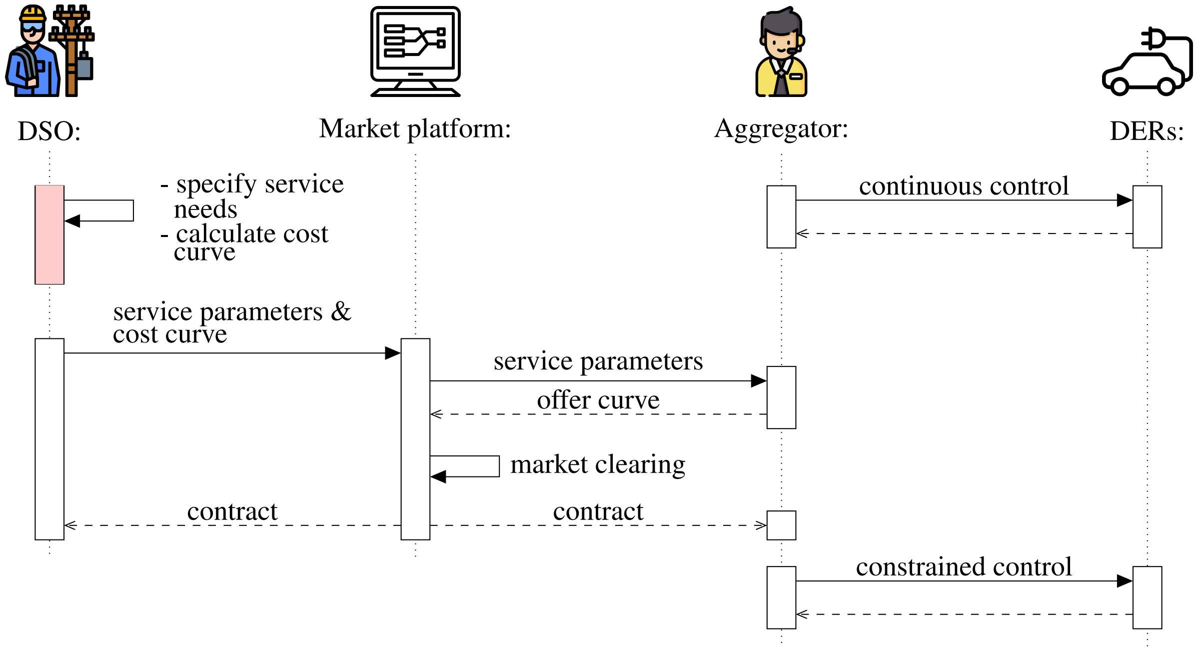

Figure 3: Sequence diagram of a DSO service request.

The DSO's cost curve and the aggregators' offer curves are then used to clear the market. It is of importance to design a proper market mechanism to efficiently allocate the service among aggregators with the goal of maximizing the overall social welfare. The market design should respect all characteristics of the LFM, especially the fact that the number of market participants is comparatively low, which means that the market is prone to strategic behaviors. After this step, standardized contracts are formed for aggregators and the DSO. Apart from the service parameters, these contracts specify the capacity limitation amount allocated to each aggregator and the respective payment.

2.3. *Main functional blocks of a local flexibility market*

In this subsection we summarize the main functional blocks that all actors need, in order to participate in an LFM. Figure 4 presents an overview of these blocks. The most important functional block is the flexibility service definition, which forms the basis for an LFM, as it defines the traded commodity. All remaining five functional blocks depend on the service definition.

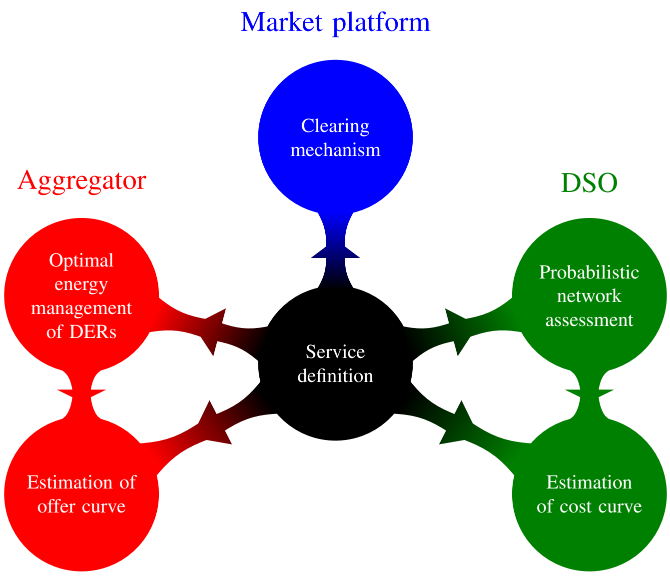

Figure 4: Main building blocks in an LFM.

Aggregators need an *optimal energy management strategy* function for their DERs. Additional constraints imposed by a service incur costs, for example when power consumption has to be shifted to hours of higher day-ahead market prices. In addition, aggregators need an *estimation of offer curve* function to quantify these costs. The DSO needs a *probabilistic network assessment* function to describe the state of the network in a probabilistic manner, both with and without any acquired services, and identify the flexibility service needs. This function forms the basis for evaluating the cost of operating the DN and deriving the DSO cost curve. The role of the market-clearing mechanism is to use the cost curve of the DSO and the offer curves of aggregators to find the flexibility service which minimizes overall system cost. The clearing mechanism must work such that market participants cannot manipulate the clearing outcome to their own advantage.

In our previous work we addressed several of these building blocks. In [23], a DER flexibility model and an aggregator control strategy for a large population of residential heaters were presented. In [17], a method to estimate the cost of offering CLSs for EV aggregators was proposed, while taking into account related uncertainties. In [19], a method for DSOs to forecast the need for flexibility services and quantify their financial benefits was presented. Building upon our previous works, the main goal of this paper is to address the important issue of CLS market clearing in an LFM, given the particular characteristics of such a market and service.

2.4. Definition of capacity limitation services

A CLS to be requested by a DSO is defined by four parameters:

- *List of service days* — containing a set of days when the capacity limitation is active.
- *Capacity limitation start time* — defining the start time of the capacity limitation for each service day.
- *Capacity limitation end time* — defining the end time of the capacity limitation for each service day.
- *List of flexible unit IDs* — defining the flexible units in the distribution grid that can deliver the service in question.

Every flexible DER is identified through a unique unit ID. Each unit ID is associated with a specific node in the network, to which the DER is connected. The DSO has knowledge of the grid topology and by specifying a list of unit IDs the requested service can target specific parts of the network that are of interest. Using these four parameters, both the DSO and aggregators can calculate cost and offer curves, which are forwarded to the market platform. According to market-clearing outcomes, contracts consisting of the following two additional components will be issued:

- *Capacity limitation* — defining the total active power consumption limit in kW allocated to the aggregator.
- *Payment* — the payment which the aggregator receives for the CLS.

3. Choice of Market-Clearing Mechanism

This section discusses different market-clearing mechanisms for an LFM with CLSs. We start by introducing several mechanisms in subsection 3.1, and then define their economic properties in subsection 3.2. Finally, subsection 3.3 analyzes and discusses the incentives of market participants under different mechanisms, considering the typical characteristics of LFMs and CLSs.

3.1. Description of the market-clearing mechanisms

Let $\mathcal{A}$ be the set of aggregators, indexed by j. We differentiate between offer curve $f_j^{\text{offer}}\left(P_j^{\text{lim}}\right)$ and true cost curve $f_j^{\text{true}}\left(P_j^{\text{lim}}\right)$. The offer curve describes the aggregator's willingness to sell a capacity limitation of P_j^{lim}. Aggregators submit their offer curves to the market platform. These are not necessarily identical to true cost curves, which represent the real underlying cost incurred by aggregators when delivering a service with a capacity limitation of P_j^{lim}. From the demand side of services, we assume that the DSO estimates the expected cost of network operation with different amounts of capacity limitations, and represents this cost through a cost function $f^{\text{DSO}}(\sum_{j\in\mathcal{A}} P_j^{\text{lim}})$.

Auctions consist of an allocation rule h and a payment rule q [24]. The allocation rule defines how the traded commodity is distributed among the participants, hence in the case of CLSs it defines the capacity limitation allocated to each aggregator. The allocation rule depends on the market participants' offer and cost curves. The payment rule specifies how much each aggregator is getting paid for the provided CLS. The two most common auction types are PAB and UP. VCG auction is less known but has interesting properties [25–27]. These three market-clearing mechanisms have the same allocation rule, defined by the minimization of the total social cost, but differ in their payment rules. Overall social cost g is defined as

$$g = \sum_{j\in\mathcal{A}} f_j^{\text{offer}}\left(P_j^{\text{lim}}\right) + f^{\text{DSO}}\left(\sum_{j\in\mathcal{A}} P_j^{\text{lim}}\right). \tag{1}$$

Using bold letters to indicate vectors, the optimization problem which minimizes g is formulated as

$$\min_{\boldsymbol{P}^{\mathrm{lim}}} \quad g \tag{2a}$$

$$\text{s.t. } P_j^{\min} \leq P_j^{\mathrm{lim}} \leq P_j^{\mathrm{nom}}, \ \forall j \in \mathcal{A}. \tag{2b}$$

Objective function g consists of the sum of all aggregator offer curves and the DSO cost curve. Variables P_j^{lim} with $j \in \mathcal{A}$ represent the capacity limitation assigned to each aggregator j. Equation (2b) constrains each capacity limitation to a value between the minimum consumption the aggregator is willing to agree upon ($P_j^{\min}$) and the aggregator's installed capacity (P_j^{nom}). We use the symbol * to denote the solution of an optimization problem hereafter. The allocation rule of all three auctions is then formulated as

$$h(\boldsymbol{f}^{\mathbf{offer}}, f^{\mathrm{DSO}}) := \boldsymbol{P}^{\mathbf{lim},*}, \text{ where } \boldsymbol{P}^{\mathbf{lim},*} \text{ is the solution of (2).} \tag{3}$$

Note that even though these three market-clearing mechanisms have the same allocation rule, this does not mean that aggregators will be assigned the same capacity limitations. An aggregator's offer depends on the underlying payment rule, and the aggregator would submit a different curve if it results in a higher profit. However, submitting curves that do not reflect the true costs leads to inefficient market outcomes. With a PAB rule, aggregators receive a payment according to their offer curve, such that

$$q_j^{\mathrm{pab}}(P_j^{\mathrm{lim},*}) = f_j^{\mathrm{offer}}\left(P_j^{\mathrm{lim},*}\right). \tag{4}$$

Under UP each aggregator is paid the same market-clearing price per sold unit. However, in the case of capacity limitations it is not straightforward to define this unit, because capacity limitations of aggregators with different portfolio sizes are not equivalent. The most intuitive approach would be to compensate each aggregator j per kW of reduction from the installed capacity P_j^{nom}. In the case of continuous offer and cost curves the market-clearing price corresponds to the marginal cost at the cleared amount. This price is equal for all market participants. The payment to aggregator j becomes

$$q_j^{\text{up}}(P_j^{\text{lim},*}) = \frac{\partial f_j^{\text{offer}}\left(P_j^{\text{lim}}\right)}{\partial P_j^{\text{lim}}}\Big|_{P_j^{\text{lim},*}} (P_j^{\text{nom}} - P_j^{\text{lim},*}). \tag{5}$$

The main idea of the VCG auction is quite elegant. All market participants receive as payment the sum of cost reductions they cause to all other participants through their participation, while the underlying allocation rule remains the same. To calculate the payment to aggregator j, the market is cleared both with and without that aggregator's participation. In our case, problem (2) is solved with an additional constraint

$$P_j^{\text{lim}} = P_j^{\text{nom}}. \tag{6}$$

$P_i^{\text{lim},-j,*}$ denotes the capacity limitation allocated to aggregator i when rival aggregator j does not participate in the market. The payment to aggregator j according to VCG is formulated as

$$\begin{aligned} q_j^{\text{vcg}}(\boldsymbol{P}^{\text{lim},*}, \boldsymbol{P}^{\text{lim},-j,*}) = f^{\text{DSO}}\left(\sum_{i\in\mathcal{A}} P_i^{\text{lim},-j,*}\right) - f^{\text{DSO}}\left(\sum_{i\in\mathcal{A}} P_i^{\text{lim},*}\right) \\ + \sum_{\substack{i\in\mathcal{A} \\ i\neq j}} \left(f_i^{\text{offer}}\left(P_i^{\text{lim},-j,*}\right) - f_i^{\text{offer}}\left(P_i^{\text{lim},*}\right)\right). \end{aligned} \tag{7}$$

The first two terms of (7) represent the difference between the DSO cost without and with aggregator j's participation, respectively. The third term represents the difference between the other aggregators' costs without and with aggregator j's participation, respectively. As we show in Appendix A, aggregators cannot make a loss through their market participation, therefore

$$q_j^{\text{vcg}}(\boldsymbol{P}^{\text{lim},*}, \boldsymbol{P}^{\text{lim},-j,*}) \geq f_j^{\text{offer}}(\boldsymbol{P}^{\text{lim},*}). \tag{8}$$

VCG auction is *incentive-compatible*. This means that when all aggregators reveal their true costs to the market, they do not have a unilateral incentive to misrepresent their true costs [24]. To ensure that DSOs also participate truthfully, their payments would have to be set up in the same manner. Denoting the capacity limitation allocation without the DSO's participation as $P_j^{\mathrm{lim},-\mathrm{DSO},*}$ for $j \in \mathcal{A}$, the corresponding payment in a VCG auction is given by

$$q_{\mathrm{DSO}}^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*}) = \sum_{j\in\mathcal{A}} \left(\underbrace{f_j^{\mathrm{offer}}\left(P_j^{\mathrm{lim},*,-\mathrm{DSO}}\right)}_{=0} - f_j^{\mathrm{offer}}\left(P_j^{\mathrm{lim},*}\right) \right). \tag{9}$$

The DSO is the only buyer in the market, so payments without DSO participation are equal to zero. $q_{\mathrm{DSO}}^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*})$ is negative (see (9)), and the DSO profits from acquiring a service, thus needs to make a payment. However, this payment is smaller than the sum of all payments which the aggregators receive, because due to (8) and (9) it holds that

$$-q_{\mathrm{DSO}}^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*}) \leq \sum_{j\in\mathcal{A}} q_j^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*}, \boldsymbol{P}^{\mathrm{lim},-j,*}). \tag{10}$$

This is problematic, as payments under the VCG mechanism do not add up to zero, and the mechanism results in a financial loss for the market operator. Due to this shortcoming, we introduce the fourth market-clearing mechanism, which we refer to as *uni-sided VCG*. In this variation of the VCG auction, the DSO simply covers all payments to the aggregators. The payment rule for the DSO under uni-sided VCG is

$$q_{\mathrm{DSO}}^{\mathrm{us\text{-}vcg}}(\boldsymbol{P}^{\mathrm{lim},*}) = \sum_{j\in\mathcal{A}} q_j^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*}, \boldsymbol{P}^{\mathrm{lim},-j,*}). \tag{11}$$

As we will show later, this weakens the incentive-compatibility property with respect to the DSO, while leading to a strict budget balance for the mechanism.

3.2. Overview of market properties

We already introduced the property of incentive-compatibility in the previous subsection. This subsection introduces five additional desirable market properties [24]:

1. An auction is called *efficient* when underlying commodities are allocated such that the over-

all social cost is minimized. This property is crucial to guarantee that society benefits from the market. In addition, this property implies that no one has an incentive to unilaterally deviate from market outcomes. The optimization problem which minimizes overall social cost is

$$\min_{\boldsymbol{P}^{\text{lim}}} \sum_{j\in\mathcal{A}} f_j^{\text{true}}\left(P_j^{\text{lim}}\right) + f^{\text{DSO}}\left(\sum_{j\in\mathcal{A}} P_j^{\text{lim}}\right) \tag{12a}$$

$$\text{s.t. } (2b).$$

Note that problem (12) describes a similar optimization problem as (1). The only difference is that here aggregators' true cost curves are considered. We denote the solution of this optimization problem as $\hat{\boldsymbol{P}}^{\text{lim},*}$. Hence, an auction which trades CLSs is efficient if, and only if, $\hat{\boldsymbol{P}}^{\text{lim},*} = \boldsymbol{P}^{\text{lim},*}$. Obviously, aggregators participating truthfully immediately implies efficiency.

2. A mechanism is called *individually rational* when participants have the incentive to participate in the market. This is the case if the expected benefit of participation is greater than zero.
3. A mechanism is called *budget-balanced* if the sum of all payments is zero. The market operator neither makes a profit nor a loss.
4. A mechanism is called *weakly budget-balanced* if the sum of all payments is zero or positive.
5. A mechanism is *revenue monotone* if total payments to the sellers remain the same or do not increase as the number of bidders grows.

In this work not all of the aforementioned properties carry the same weight. Efficiency is often considered as the most important property as it ensures that trades result in a social benefit. Further, budget-balancedness is considered crucial, as a subsidy for the mechanism would be undesirable and might result in a cross-subsidy of the aggregator's business. Individual rationality of aggregators ensures that aggregators benefit from trades and are therefore willing to offer

CLSs. Therefore, this property is important for the long-term functionality of the setup. Finally, revenue monotonicity and collusion aversion are considered *nice-to-have* properties as they can theoretically be addressed with regulation.

3.3. Comparison of properties of different market-clearing mechanisms

It has been proven that, in general, there exists no efficient, incentive-compatible and individually rational mechanism which also balances the budget [28]. Therefore, none of the mechanisms considered in this paper is able to hold all four properties at the same time. Both PAB and UP are generally known to be inefficient [24]. The so-called bid shading effect[1] incentivizes market participants to bid untruthfully, such that the market outcome might not be socially optimal [29]. In a PAB market, truthful aggregators are unable to make a profit. On the other hand, UP is only asymptotically efficient, meaning that a high number of aggregators have to offer CLSs such that all are price-takers, and they cannot significantly influence market outcomes to their own profit. However, recall that an LFM is expected to have a few participating aggregators. In Appendix B we prove that aggregators are always able to increase their profits by inflating their offers under both UP and PAB. The proof assumes exponential functions for offer and cost curves. Subsections 5.2.1 and 5.2.2 will show that it is a reasonable assumption.

A series of works have recently considered the VCG mechanism for electricity markets [30–32] and have assessed how the additional uncertainty of intermittent renewable generation affects the mechanism's performance [33]. On an LFM for CLSs, issues related to uncertainty stemming from renewable sources would not affect the performance of the clearing mechanism, as this uncertainty would be encapsulated in aggregator and DSO cost curves. Unlike PAB and UP, the VCG auction is efficient, incentive-compatible and individually rational. However, it does not guarantee the satisfaction of budget-balancedness. In cases where the VCG auction makes a surplus, this can be redistributed among market participants without affecting incentive-compatibility, making the

[1]Strategic bid shading or demand reduction describe the case where market participants understate their true demand or supply curve in order to compensate for the winner's curse.

mechanism *ex-post budget-balanced*. Unfortunately, VCG auction does not generate a surplus in our setup, and it has been shown [34] that if this is the case, no efficient, incentive-compatible and individually rational mechanism exists, which balances the budget in an ex-post manner. To restore budget-balancendness, we make concessions on incentive-compatibility and individual rationality by introducing the uni-sided VCG mechanism.

In the uni-sided VCG auction, aggregators receive payments according to the VCG payment rule, all compensated by the DSO. This means that aggregators are guaranteed to make a non-negative profit through participation, while they still have the incentive to report their true cost. DSOs, on the other hand, might have an incentive to conceal their true cost. As they are strictly regulated natural monopolies, we do not consider the missing incentive-compatibility to be a large issue. All UP, PAB and VCG are individually rational. However, with the uni-sided VCG, under some circumstances DSOs may make a loss from acquiring a service.

Both UP and PAB are revenue monotone, as an additional aggregator can only reduce the price that the buyer pays for a specific quantity. Both VCG and uni-sided VCG are not revenue monotone. This may result in a circumstance wherein aggregators could increase their profit by partitioning their portfolio — a situation prone to shill bidding [30]. However, such an intentional partitioning into several commercial entities bears many administrative, practical and commercial barriers in the overall operation of an aggregator. Further, VCG mechanisms are known to be prone to collusion [34, 35]. While aggregators do not individually have an incentive to inflate their offer, two aggregators that inflate their offers in a coordinated manner are able to increase their earnings.

Table 1 summarizes the properties of different clearing mechanisms. Due to the missing efficiency, PAB and UP are not appropriate for a CLS market. Since VCG is not weakly budget-balanced, it cannot be implemented without a subsidy. This disqualifies VCG as the mechanism of choice. The proposed uni-sided VCG mechanism is budget-balanced and has all desirable properties on the aggregator side. We therefore propose to use it as the clearing mechanism of an LFM

Property	UP	PAB	VCG	Uni-sided VCG
Efficient	✗	✗	✓	(✓)
Agg. incentive-compatible	✗	✗	✓	✓
DSO incentive-compatible	✗	✗	✓	✗
Agg. individually rational	✓	✓	✓	✓
DSO individually rational	✓	✓	✓	✗
Budget-balanced	✓	✓	✗	✓
Collusion averse	✓	✓	✗	✗
Revenue monotone	✓	✓	✗	✗

Table 1: A summary of properties hold or lost in different market-clearing mechanisms. Parentheses indicate that properties hold, under the assumption that the DSO reports cost truthfully.

trading CLSs. The uni-sided VCG mechanism has two main disadvantages, i.e., missing revenue monotonicity and the possibility of collusion. We hypothesize that in practice the cost of intentionally splitting an aggregator's portfolio would exceed the potential increase in earnings from offering CLSs in an LFM. However, the potential for collusion represents a property that legislators would have to be particularly wary of. We provide a more thorough discussion on these points in the policy implications discussion in section 6.

4. Cost Functions of Aggregators and DSO under CLSs

Subsection 4.1 presents a method to calculate the cost that aggregators incur when offering CLSs. This allows them to determine their true underlying cost function. Subsection 4.2 explains how the DSO calculates the cost of operating the network with CLSs.

4.1. Derivation of the cost function of aggregators

CLSs constrain the operation of aggregators by requiring them not to exceed some given power limits during specific time periods. These additional power constraints lead to higher operational costs. Let $P_{k,t}$ be the power consumption of the k-th DER within the portfolio of the underlying aggregator at time step t. $\boldsymbol{P}$ is a matrix containing all DER power consumption values at all time steps in the underlying time horizon. The cost of each aggregator is minimized as

$$\min_{\boldsymbol{P},\boldsymbol{\xi}} \; f^{\text{opt}}(\boldsymbol{P},\boldsymbol{\xi}) \tag{13a}$$

$$\text{s.t.} \; y^{\text{opt}}(\boldsymbol{P},\boldsymbol{\xi}) \leq 0 \tag{13b}$$

$$z^{\text{opt}}(\boldsymbol{P},\boldsymbol{\xi}) = 0, \tag{13c}$$

where $f^{\text{opt}}(\boldsymbol{P},\boldsymbol{\xi})$ is the aggregator's cost function, and other state variables are contained in $\boldsymbol{\xi}$. The aggregator has to respect inequality constraints $y^{\text{opt}}(\cdot)$ and equality constraints $z^{\text{opt}}(\cdot)$. The solution of (13) is denoted by $\boldsymbol{P}^{\text{wo},*}$, and defines a power schedule for all DERs without any CLS-related constraints. When aggregator j offers a CLS of P_j^{lim}, a set of additional constraints is added to (13) as

$$\sum_{k\in\mathcal{B}} P_{k,t} \leq P_j^{\text{lim}} \quad, \forall t \in \{t_{\text{start}}, ..., t_{\text{end}}\}. \tag{14}$$

Here, P_j^{lim} is not time-dependent, as the capacity limitation is the same for all time steps. Symbol $\mathcal{B}$ denotes the set of the aggregator's DERs in the area of interest. Optimization problem (13), subject also to constraint (14), forms the aggregator optimization problem when offering the CLS. We denote the solution of the problem with CLS constraints by $\boldsymbol{P}^{\text{w},*}(P_j^{\text{lim}})$, which is now a function of P_j^{lim}. For notational simplicity we omit $\boldsymbol{\xi}$ when we refer to the solution of the optimization problem. The cost C^{agg} of offering a CLS of P_j^{lim} can then be expressed as

$$C^{\text{agg}}(P_j^{\text{lim}}) = f^{\text{opt}}(\boldsymbol{P}^{\text{w},*}(P_j^{\text{lim}})) - f^{\text{opt}}(\boldsymbol{P}^{\text{wo},*}). \tag{15}$$

To create the aggregator's offer curve, the second optimization problem is repeatedly solved for different values of P_j^{lim}.

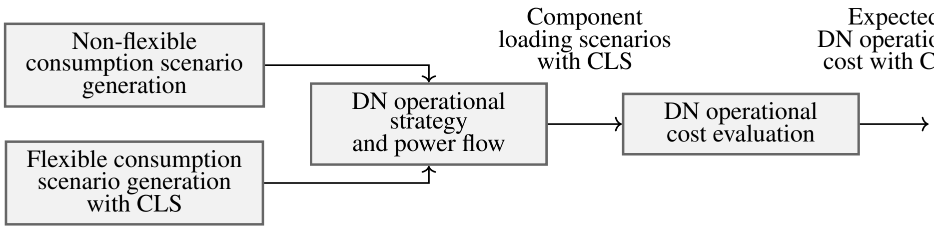

Figure 5: Flowchart of the calculation of DN operational cost with a CLS.

4.2. Derivation of the DSO cost function

Aggregators that provide CLSs have limited network access, resulting in a lower network loading. This can prevent or defer grid reinforcements. Further, CLS can prevent power outages in the DN, leading to lower compensation fees which have to be paid to customers, and improved performance metrics which are decisive for the DSO's rate-of-return. Therefore, such services bring financial benefits to the DSO.

Figure 5 illustrates a process of how a DSO can quantify the cost of operating the DN with CLSs. These services are formulated as active power consumption caps on flexible consumption, but do not affect the non-flexible counterpart. Therefore, probabilistic load models for both flexible and non-flexible consumption must be used to analyze how CLSs affect power flows throughout the network.

CLSs are split among aggregators, with the exact allocation eventually being determined by the market. Beforehand, the DSO does not know how capacity limitations will be allocated, and must therefore estimate the likely combinations. Given a specific allocation, the DSO can model the power consumption of aggregators who operate under capacity limitations.

The power consumption scenarios generated by the DSO are translated into a set of DN component loading scenarios, by considering possible DSO corrective actions (e.g. load curtailment) and running power flow calculations. Component loading scenarios are used to calculate the expected cost of DN operation. This cost evaluation can include the value of lost load (VOLL), DN power losses, equipment reduction of life expectancy, etc. The process is carried out repeatedly for

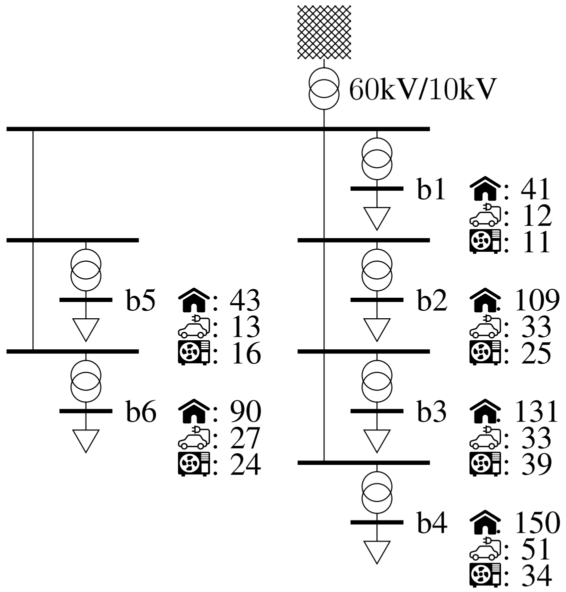

Figure 6: Distribution grid model (adapted from [19]).

different values of P^{lim} to create the DSO's cost curve. The difference of the expected operating cost with and without a service represents the expected financial benefit of the CLS in question.

5. Illustrative Case Study

This section presents a case study which illustrates how CLSs can be used to operate the DN more economically. Subsection 5.1 provides a description of the case study. Subsections 5.2.1 and 5.2.2 present the resulting aggregator offer curves and DSO cost curves, respectively. Based on these results, subsection 5.3 discusses the market outcomes when using the proposed uni-sided VCG mechanism to clear the LFM of the case study.

5.1. Case study description

We consider a real radial medium voltage feeder, shown in Figure 6, located on the Danish island of Bornholm. The feeder supplies 564 residential customers. The load data was collected in the context of the Danish project EcoGrid 2.0 [36]. All households own either a heat pump or a resistive heater. Therefore, the highest consumption occurs when heat demand peaks during winter months. Accordingly, we use weather and meter data from January 2019, and a service period of one month is considered.

EVs and resistive heaters are considered as flexibility sources. The former are generally considered to be the most important source of DER flexibility in DNs [37], due to a fairly high charging power combined with a large storage capacity. Further, EV sales are expected to increase steadily throughout the next decade [38]. For this reason, in this case study we assume that a larger share of flexibility originates from EVs. It is assumed that 30% of all households own an EV, which charges with a nominal power of 3.68 kW. EVs are controlled by two aggregators. The first, referred to as agg. 1, controls a portfolio of 101 EVs with $P_1^{\text{nom}} = 371.68$ kW. The second, referred to as agg. 2, controls 68 EVs with $P_2^{\text{nom}} = 250.24$ kW. Both aggregators optimize charging patterns such that EVs reach a state of charge (SOC) of 100% by their time of departure, while minimizing the total energy costs in the day-ahead market. The probability distribution functions for arrival and departure times and the SOC upon arrival are taken from [39]. EV batteries have a storage capacity of 24 kWh and charge with an efficiency of 90%. As this serves as an illustrative case study, we make a simplifying assumption that aggregators have full knowledge of the day-ahead prices [40], arrival/departure times and the initial SOC values.

An additional third aggregator (agg. 3) controls resistive heaters from 150 homes. Heaters are modelled using a first-order model [41], [42] and employing a concept known as the thermal battery model [43], [44] to describe the aggregated flexibility. The thermal battery model is explained in more detail in Appendix C. Results from the EcoGrid 2.0 project [36] are used to obtain realistic values for the heating systems [23]. The analysis showed that the equivalent battery power is approximately 1.68 kW for each house, thus $P_3^{\text{nom}} = 252$ kW. The aggregator schedules the residential heating units such that customer comfort is maintained, while minimizing energy acquisition costs in the day-ahead market.

We simulate a congestion in the primary substation, and evaluate the cost of lost load. For this purpose, the rating of the transformer station has been artificially reduced to 1200 kVA. Slightly exceeding the transformer's rated power for a short period is usually not an issue. However, transformers are equipped with a protection switch. It is assumed that the transformer is disconnected when consumption exceeds 120% of its rating, at 1440 kVA. In most cases of faults in medium voltage networks the grid can be reconfigured, such that all customers are quickly reconnected to the grid. We therefore assume that the load will be interrupted for five minutes only. Flexible and non-flexible consumption is aggregated on the secondary feeders, and power losses in the 400 V network have been neglected. As resistive heaters have no reactance and the power factor of EV inverter chargers can usually be adjusted, flexible loads are modelled with a power factor of 1.

5.2. Derivation of cost curves

This section derives aggregator cost functions in subsection 5.2.1 and the DSO cost function in subsection 5.2.2.

5.2.1. Aggregator cost

Aggregators minimize their costs with and without offering a CLS, according to section 4.1. The optimization problem formulations for resistive heaters and EVs are detailed in Appendix C and Appendix D, respectively. The resulting costs for different P^{lim} values are shown in Figure 7 with hollow circles. Squares indicate the installed capacity of aggregators. Naturally, capacity limitations higher than the aggregators' P^{nom} have zero costs, as they do not affect the aggregators' actions in any way. The minimum capacity limitations that aggregators can offer are indicated by triangles in Figure 7.

Agg. 3 is less flexible, and the costs of lowering the capacity limitation rise faster, compared to the EV aggregators. Agg. 1 and agg. 2 rarely operate their portfolio close to the nominal power, since most of the time some EVs are absent or already fully charged. Therefore, a capacity limitation equal to 80% of P^{nom} barely increases cost for the EV aggregators (at a cost of 0.26 DKK per EV). On the contrary, a capacity limitation of 80% of P^{nom} for agg. 3 leads to a cost of 6.8 DKK per heater, because this aggregator regularly operates the portfolio close to nominal power.

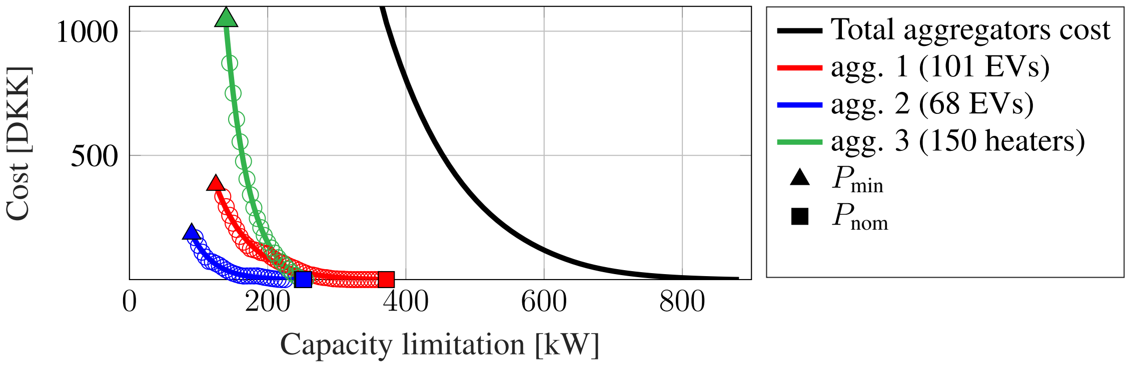

Figure 7: Three examples of aggregator cost curves as well as their total cost curve. Hollow circles indicate individual results, while continuous curves are fitted.

The cost curves of all three aggregators indicate an exponential shape. This is in agreement with [17]. Based on such findings, we represent the aggregator costs of offering CLSs as

$$C^{\text{agg}}\left(P^{\text{lim}}\right) = a \exp\left(bP^{\text{lim}}\right) + c, \tag{16}$$

where $a > 0$, $b < 0$. We set $c = -a \exp\left(bP^{\text{nom}}\right)$ to ensure that aggregator costs are zero at their nominal capacity, therefore $c < 0$. The fitted exponential functions are shown in Figure 7 as continuous curves. As part of the market clearing, the market platform combines the individual cost curves to derive an overall cost curve for the service, given by the sum of the capacity limitations of all aggregators. This combined curve, shown in black color in Figure 7, represents the total cost to achieve a certain capacity limitation when the service is optimally distributed between aggregators.

5.2.2. *DSO cost*

This subsection quantifies the DSO cost of network operation with CLSs according to the method described in subsection 4.2. Figure 8 shows the apparent power flow through the transformer station on a cold winter day, with and without a CLS. The blue curve corresponds to the non-flexible consumption, and the red curve to the total one. Flexible consumption patterns are the result of aggregator control and are more volatile compared to the fairly smooth and more

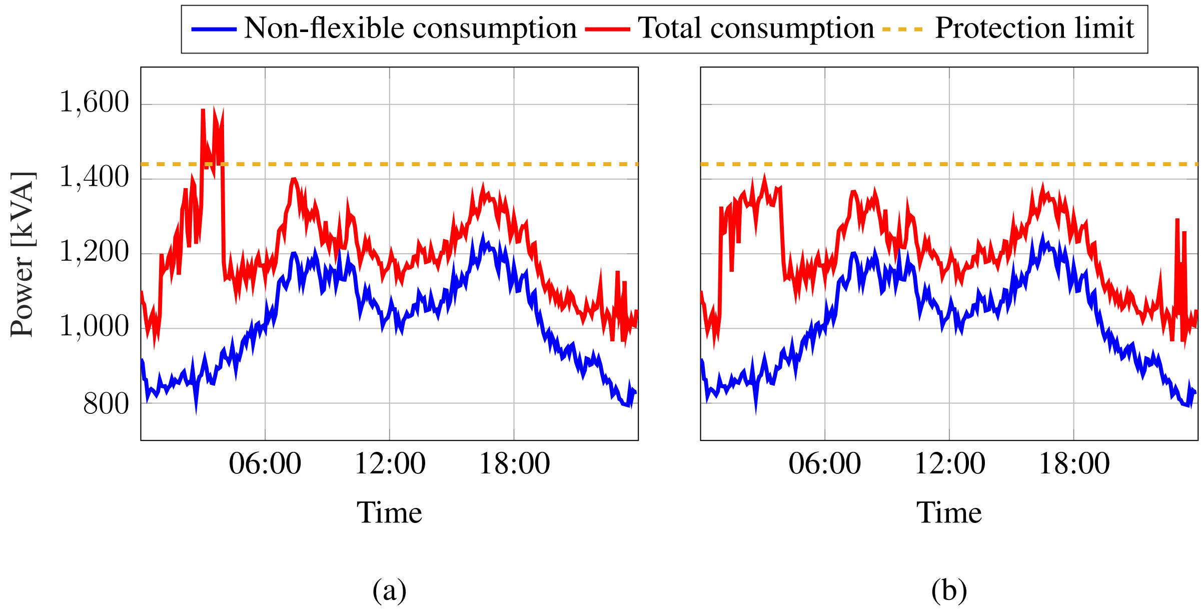

Figure 8: Power flow through transformer station on the 26th of January 2019, (a): no CLS - (b): CLS of 500 kW.

predictable non-flexible consumption. Many EVs charge at night, when day-ahead prices are comparatively low. Without a capacity limitation this leads to congestion in the DN during off-peak hours (Figure 8 (a)). The control strategy of the aggregators would trigger the protection of the transformer, leading to the disconnection of the entire feeder. To prevent the potential power outage, the DSO can request a CLS. A CLS of 500 kW would have the desired effect, preventing faults during early morning hours (Figure 8 (b)).

To be able to participate in the LFM, the DSO has to derive a cost curve which specifies the DN operational cost under different capacity limitations. For this purpose, the VOLL can be used, which can reach prices of up to 120 DKK per kWh [45]. The VOLL represents the residential customers' point of view, and their willingness to pay to prevent outages, but not the actual cost of such events for the DSO. Therefore, using it would significantly overestimate the DSO's real willingness to pay for a service. The authors of [46] quantify the real DSO cost of lost load by shadow pricing based on publicly available DSO data from Finland. They estimate that DSOs in Finland pay between zero and five eurocents as compensation fees per interrupted minute and customer, with an average of 0.5 eurocents. As these findings consider the DSOs' point of view, they are better suited to represent its willingness to pay for flexibility services. It is therefore assumed that DSOs are willing to pay at most 0.5 eurocents per customer per minute to prevent a power outage with the help of a flexibility service. To calculate the cost of a particular capacity limitation, the amount of time steps where total consumption exceeds the transformer security limit are counted, and the value is multiplied with the corresponding cost per time step. Dynamics, such as a rebound [47] after an outage, are neglected.

As described in subsection 4.2, the DSO has to make assumptions regarding the aggregators' control strategies and the market allocation of the CLS. To determine network operational cost under different CLSs, the DSO needs to carry out a probabilistic network assessment to account for uncertainties due to aggregator behaviour or inflexible load variability, and the effect of potential grid reconfiguration. The exact realization of the resulting cost curve will thus depend on grid topology, the penetration of flexible DERs, possible reconfigurations, the number of active aggregators in the network, etc. In this illustrative case study we are merely interested in the shape of the DSO's cost curve. We intend to study the service request methodology and the determination of DSO cost in more complicated but realistic scenarios in our future research. Here, we assume that the DSO has perfect knowledge of the aggregator load profiles under different capacity limitation constraints. In addition, it is assumed that the DSO perfectly knows how the market would allocate each specific capacity limitation to different aggregators.

The resulting DSO costs are shown in Figure 9. The DSO benefit corresponds to the difference in operational cost without and with a CLS. According to Figure 9, flexible consumption reaches a maximum value of 825 kW without a CLS. This situation would lead to regular short power interruptions in the feeder, which would cost the DSO 6770 DKK. Certainly, under such circumstances the DSO would reinforce the grid to ensure security of supply. A CLS of 725 kW, which only reduces the possible peaks by at most 100 kW already reduces the DSO cost to 2850 DKK, resulting in a benefit of 3920 DKK. Costs eventually drop to zero at around 460 kW, at which point

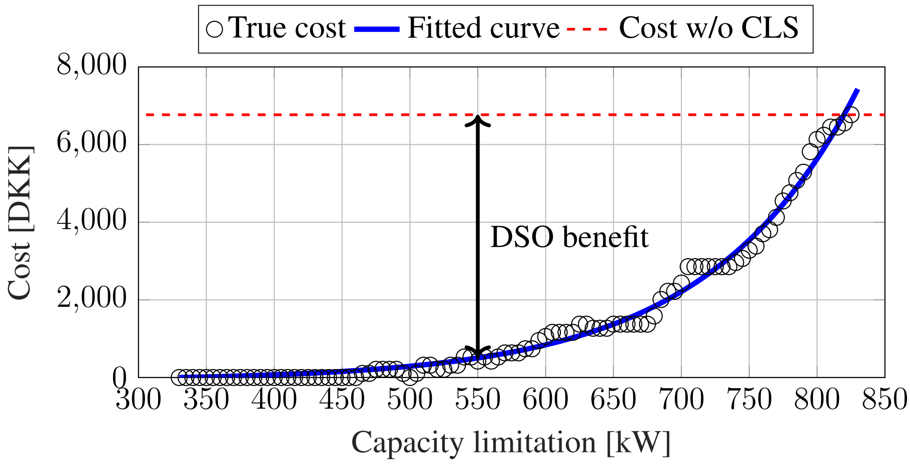

Figure 9: DSO cost curve for different amount of CLSs. Hollow circles indicate individual results, while the continuous curve is fitted.

no transformer limit violations occur. The DSO cost curve shows an exponential shape. Therefore, in the remainder of the paper, the DSO cost is modelled with an exponential function as

$$C^{\text{DSO}}\left(P^{\text{lim}}\right) = \alpha \exp(\beta P^{\text{lim}}) + \gamma, \tag{17}$$

where $\alpha, \beta > 0$. The corresponding fitted function is shown as the blue curve in Figure 9.

5.3. Uni-sided VCG results

In this subsection we numerically verify the suitability of the the proposed uni-sided VCG mechanism using the case study. Due to the incentive-compatibility of the mechanism on the aggregators' side, they are expected to submit their true cost curves $f^{\text{true}}(\cdot)$. In subsection 5.3.1 the market outcome is presented and discussed, whereas in subsection 5.3.2 a sensitivity analysis with respect to some key parameters is conducted.

5.3.1. Market outcome

Figure 10 shows the result of the uni-sided VCG market clearing. Circles indicate the costs that aggregators incur when offering the services, and the operational cost of the DSO when acquiring such said services. Triangles indicate the participants' payments. Table 2 summarizes the aggre-

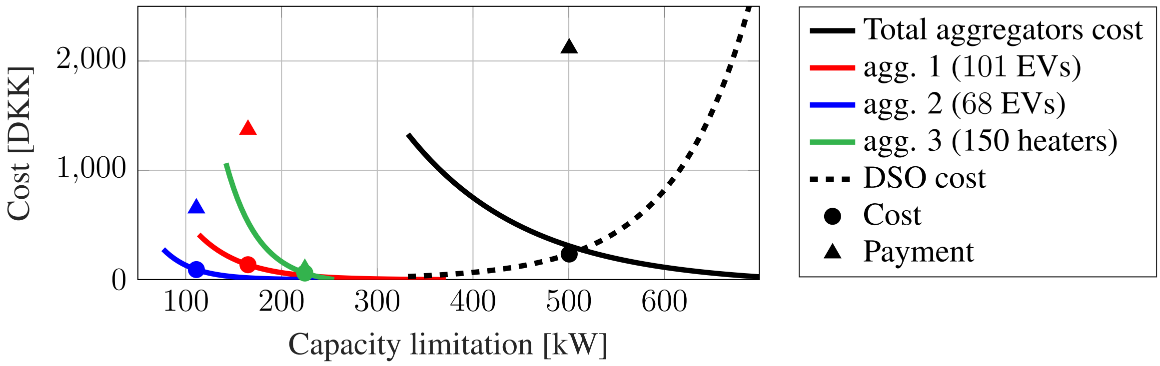

Figure 10: Market-clearing outcome of the proposed uni-sided VCG mechanism.

gator profits. EV aggregators receive the majority of the payments, as they provide the largest share of the CLS. This is a result of less steep cost curves, compared to agg. 3. Notice how their respective curves in Figure 7 increase at a much lower rate than that of agg. 3. As a result, agg. 3 does not contribute considerably to the overall capacity limitation as the value of the CLS lays only 30 kW below the nominal power. The reason is that heating systems are not as flexible as EVs. The profit is only 1.1 DKK per heater, $8-12$ times less than each EV. Since heating systems have a considerably smaller nominal power, this figure drops to $3-5$ times when considering profits per kW of installed capacity. Agg. 2 has the largest portfolio in terms of installed capacity, and thus a more dominant market position. Under the uni-sided VCG this dominant position results in a higher payment not only in absolute terms, but also in a higher profit per DER and kW of installed capacity. As a result, the profit of agg. 2 per DER is 50% higher than that of agg. 1.

Table 2: Summary of aggregators' profits expressed in DKK.

Aggregator	Portfolio	$P^{\mathrm{lim},*}$ [kW]	Total profit	Profit per DER	Profit per kW of installed capacity
1	101 EVs	164	1372	12.2	3.3
2	68 EVs	111	653	8.3	2.2
3	150 heaters	224	234	1.1	0.7

The CLS is also beneficial for the DSO. As already observed in Figure 9, without a CLS the DSO would face a total operational cost of 6770 DKK. By acquiring a CLS of 500 kW, this cost is reduced to 2350 DKK. Out of this cost, 2117 DKK are spent to pay aggregators for the provision of CLSs, and the remaining 233 DKK are the remaining compensation fees to customers. These results show that both aggregators and the DSO benefit from an LFM built upon the proposed uni-sided VCG auction.

5.3.2. Sensitivity analysis

The mechanism is not incentive-compatible with respect to DSOs, as they cover all aggregator payments. In these cases, DSOs have incentive to misreport their true cost functions. As this would make the market inefficient, such situations should be avoided. Further, there could be cases where aggregator payments exceed the DSO's benefit, and the latter would not be willing to acquire non-beneficial services. To understand how likely these situations are, a sensitivity analysis is carried out to illustrate how the market clearing responds to changes in aggregator flexibility share, network loading, and the cost of lost load. To this end, the test case was run again with the number of EVs controlled by agg. 1 varied, while keeping the total number of EVs the same, with the transformer rating changed to emulate high loading, and with varied cost of lost load. These results are shown on Figures 11 and 12 for DSO benefits and aggregator profits, respectively.

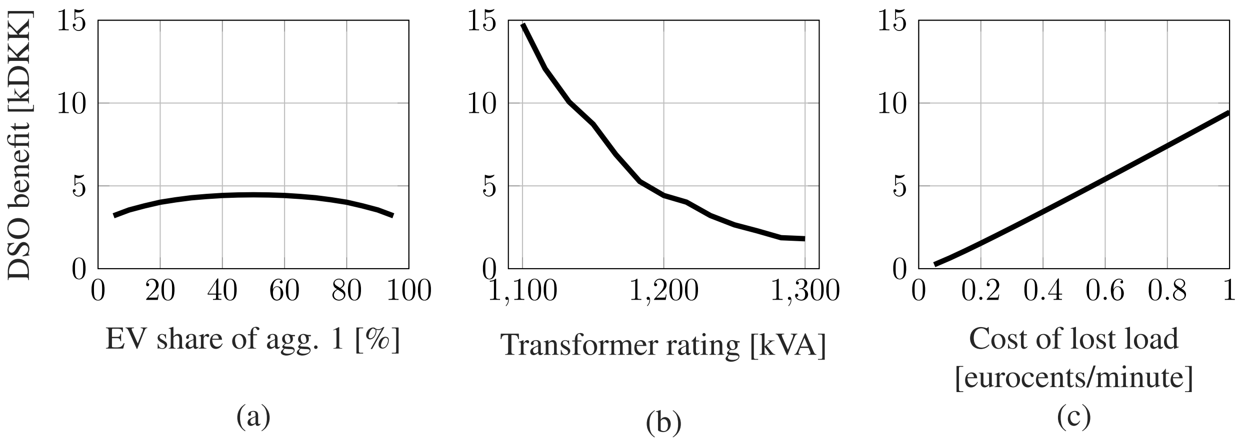

Figure 11: Sensitivity of DSO benefit under uni-sided VCG.

For this case study, we find no situation in which the DSO ends up with a net loss. As seen in Figures 11, the DSO benefit is positive in all considered cases - when altering the share of

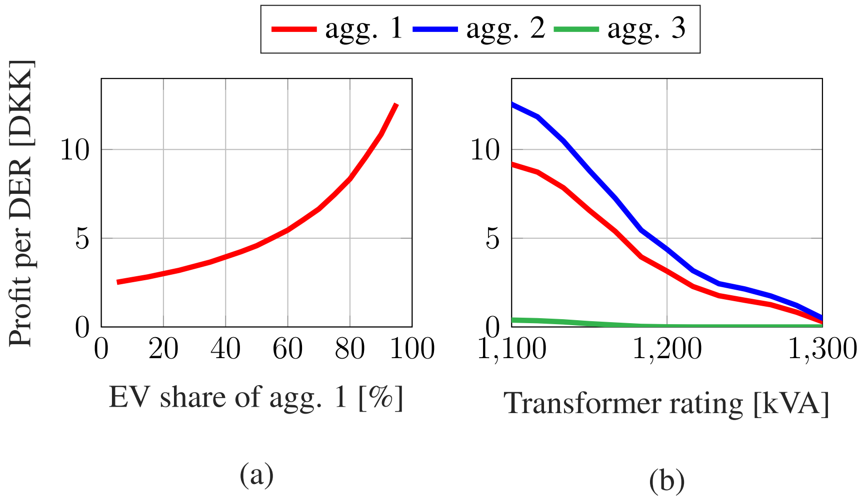

Figure 12: Sensitivity of aggregators' profit.

EVs controlled by agg. 1, changing the rating of the transformer, or changing the cost of lost load. While the issue of DSOs ending up with negative benefits as a result of uni-sided VCG is a theoretical possibility, our investigation has not uncovered such a situation.

Further, note that the DSO benefit in Figure 11 (b) and the aggregator profit per DER in Figure 12 (b) drop sharply with increased transformer rating. In the current setup, components in DNs are usually oversized. Since DSO benefits and potential aggregator profits are significantly reduced at lower network loading, there is a lower need for creating a service market, and a reduced push to establish these markets. Thus, current investment strategies in DNs may be preventing the formation of markets for flexibility services, even if those markets would bring a net benefit to the overall system.

Finally, Figure 12 (b) indicates that aggregators with a more dominant market position have a higher revenue per DER. Since this revenue represents how much the aggregator is willing to refund each individual DER, larger aggregators are able to offer greater incentives to DERs, which can cause a drift towards high market concentration. However, since high market concentration also slightly decreases DSO benefits, as shown in Figure 12 (a), the DSO has an active interest in ensuring there is a sufficient diversity of aggregators in the grid. We note finally, that aggregators with a very small portfolio share are still able to make a profit, ensuring that a business case exists for aggregators in systems where few DERs are involved in service provision.

6. Conclusion and Policy Implications

This work investigates potential market-clearing mechanisms for LFMs with CLSs and reveals that PAB, UP and the VCG mechanisms do not satisfy the critical economic properties for such markets. Therefore, an alternative mechanism is proposed in this paper, namely uni-sided VCG, which provides a proper trade-off between budget-balancedness, incentive-compatibility and individual rationality. The proposed mechanism is applied in a case study, where typical aggregator offer curves, as well as the DSO's cost curves, are found to have an exponential shape. Given these findings, the uni-sided VCG market outcome is found to be beneficial for both aggregators and the DSO, resulting in an increase of overall social welfare.

6.1. Policy implications

There is a series of relevant aspects which have to be considered when implementing an LFM using CLS. In the following we address the most important ones by providing a number of policy recommendations at the same time.

- *Aggregators must not misreport installed capacity*
  In the proposed uni-sided VCG mechanism aggregators can theoretically manipulate the market outcome even when they do not participate in the market. They can achieve this by misrepresenting their installed capacity, which could theoretically affect the worst-case scenario assumptions of a DSO. For this reason, the mechanism is incentive-compatible under the condition that aggregators report their true installed capacity. Accordingly, the incentive-compatibility property of the uni-sided VCG auction only holds if the true installed capacity of aggregators is known.

Thus, market regulators have to ensure that this value cannot be misrepresented. It is usually straightforward for the DSO to identify the correct value of each flexible asset's installed capacity from the relevant connection agreements.

- *Need for fall-back option*

  The uni-sided VCG mechanism is only able to calculate a payment for an aggregator if it is possible to clear the market without that particular aggregator's participation. There could be a case where an aggregator has a very dominant position in the auction, such that market clearing is impossible when that aggregator is excluded, as part of the payment calculation. This also means that the mechanism is unable to calculate payments for a DN with only one aggregator. In such cases, payments would have to be found differently. A *take-it-or-leave-it* price or a *price cap* could be possible fall-back options in such situations.

- *Preventing collusion*

  VCG-based mechanisms are known to be vulnerable to collusion [34]. While individual aggregators are not able to increase their profits by being untruthful, two aggregators, who both misreport their cost, can increase payments for each other. This potential collusion is an issue in many markets, and it is usually unlawful. In an LFM, excessive collusion would render the services unprofitable for DSOs, who would then have to expand their network. This acts as a deterrent against collusion, because grid expansion would eliminate the aggregators' additional revenue from the LFM. In addition, legislators should impose strict rules which forbid any potential collusion between aggregators.

- *Aggregators must not artificially split their portfolio*

  VCG-based mechanisms are not necessarily revenue monotone [48]. Aggregators can boost their profits by artificially creating several entities [49], thus easing internal collusion and being able to influence the market outcome at their benefit. However, an intentional partition into several entities bears numerous administrative, practical and commercial/branding barriers in the overall operation of an aggregator. It is thus highly unlikely that any increase in earnings in the LFM would justify such a decision, but the market regulator should prohibit any aggregator(s) from operating under such terms.

- *DSOs have to report their cost truthfully*

  Payments and incentives are only compromised from the DSO side. Unlike aggregators, the DSO has an incentive to report lower costs and thus increase the profitability of acquiring a certain service. However, DSOs are strictly regulated monopolies which do not follow the principles of profit maximization, and their actions are closely monitored by regulators. It is thus expected that DSOs will participate truthfully in the market. Not doing so could potentially dissuade aggregators from offering flexibility services, and the DSO would eventually need to consider more expensive options such as grid reinforcement.

6.2. Implications on the interaction between system operators

Under the current regulation in Denmark, aggregators can participate in the wholesale market or offer TSO-level ancillary services (e.g., balancing power or primary frequency control) by controlling DERs which are connected to the DN. As already discussed, load synchronization might cause congestion and result in additional operational cost to the DSO. If an aggregator's participation in the energy or ancillary service markets results in the disconnection of a feeder, the resulting social losses can quickly exceed the potential system benefit of this participation. However, in a future market setup with a functional LFM, aggregators will have the possibility to offer their services both locally to DSOs and to the wholesale energy and ancillary service markets.

If aggregators offer CLSs, this will simply restrict their participation in the system-level markets, however only to the extent which is necessary to prevent network congestion. In that context, DSOs would compete for flexible resources, but in a way that restricts any harmful behaviour of aggregators, e.g., sudden load increases while offering down-regulation in the balancing market. If a high risk of congestion occurs in a DN, it can be expected that DSOs would request services at prices that benefit aggregators, and which overcompensate them for any opportunity costs at the TSO-level markets. This would happen due to the simple fact that the VOLL in the case of feeder disconnection is significantly higher the respective profits from the TSO-level market. Therefore, the parallel operation of the LFMs along with the TSO-level markets will ensure that flexibility resources are allocated where the potential gains and the corresponding social benefits are highest.

Acknowledgement

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Appendix A. Vickrey-Clarke-Groves is individually rational

An aggregator j can only reduce overall system cost by participating in the market, hence

$$g\left(\boldsymbol{P}^{\mathrm{lim},-\boldsymbol{j},*}\right) - g\left(\boldsymbol{P}^{\mathrm{lim},*}\right) \geq 0. \tag{A.1}$$

The payment that aggregator j receives is given by

$$q_j^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*}, \boldsymbol{P}^{\mathrm{lim},-\boldsymbol{j},*}) = g\left(\boldsymbol{P}^{\mathrm{lim},-\boldsymbol{j},*}\right) - f_j^{\mathrm{offer}}(P_j^{\mathrm{lim},-j,*}) - g\left(\boldsymbol{P}^{\mathrm{lim},*}\right) + f_j^{\mathrm{offer}}(P_j^{\mathrm{lim},*}). \tag{A.2}$$

Since $f_j^{\mathrm{offer}}(P_j^{\mathrm{lim},-j,*}) = 0$, we get

$$q_j^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*}, \boldsymbol{P}^{\mathrm{lim},-\boldsymbol{j},*}) = g\left(\boldsymbol{P}^{\mathrm{lim},-\boldsymbol{j},*}\right) - g\left(\boldsymbol{P}^{\mathrm{lim},*}\right) + f_j^{\mathrm{offer}}(P_j^{\mathrm{lim},*}). \tag{A.3}$$

Combining (A.1) and (A.3) results in

$$q_j^{\mathrm{vcg}}(\boldsymbol{P}^{\mathrm{lim},*}, \boldsymbol{P}^{\mathrm{lim},-\boldsymbol{j},*}) \geq f_j^{\mathrm{offer}}(P_j^{\mathrm{lim},*}). \tag{A.4}$$

Appendix B. PAB and UP are not incentive-compatible

Let us consider the case where only two aggregators are active in a DN. The shape of the true underlying cost of agg. 1, i.e., f_1^{true}, is defined by (16). Say agg. 1 slightly inflates the bid by ϵ, such that

$$f_1^{\text{offer}} = (a_1 + \epsilon)\exp(b_1 P_1^{\text{lim}}) + c, \tag{B.1}$$

while agg. 2 bids truthfully. To show that UP and PAB are not incentive-compatible, it is necessary to show that aggregators can increase their profit by manipulating their offer curve. For this purpose, we will calculate agg. 1's profit, and show that the partial derivative of the profit by the manipulation term ϵ is greater than zero. First, we calculate some necessary equations, which we use to complete the proofs in Appendix B.1 and Appendix B.2.

We know that the market clears such that the marginal cost of both aggregators corresponds to the marginal DSO benefit. The marginal cost of aggregators MC^{agg} and marginal cost of the DSO MC^{DSO} represent the derivatives of (16) and (17), i.e.,

$$MC_1^{\text{agg}}(P_1^{\text{lim}}) = \frac{\partial f_1^{\text{offer}}}{\partial P_1^{\text{lim}}} = (a_1 + \epsilon) b_1 \exp(b_1 P_1^{\text{lim}}), \tag{B.2}$$

$$MC_2^{\text{agg}}(P_2^{\text{lim}}) = a_2 b_2 \exp(b_2 P_2^{\text{lim}}), \tag{B.3}$$

$$MC^{\text{DSO}}(P_1^{\text{lim}} + P_2^{\text{lim}}) = \alpha\beta \exp(P_1^{\text{lim}} + P_2^{\text{lim}}). \tag{B.4}$$

Through the market balance condition $MC_1^{\text{agg}}(P_1^*) = MC_2^{\text{agg}}(P_2^*)$ we can derive that

$$P_2^* = \frac{g}{b_2} + \frac{b_1}{b_2} P_1^*, \tag{B.5}$$

where $g = \ln(\frac{(a_1+\epsilon)b_1}{a_2 b_2})$. We also know that $MC_1^{\text{agg}}(P_1^*) = MC^{\text{DSO}}(P_1^* + P_2^*)$, so

$$h + b_1 P_1^* = \beta(P_1^* + P_2^*), \tag{B.6}$$

with $h = \ln(\frac{(a_1+\epsilon)b_1}{\alpha\beta})$. Combining (B.5) and (B.6) leads to

$$P_1^* = \frac{b_2 h - \beta g}{\beta(b_1 + b_2) - b_1 b_2}. \tag{B.7}$$

It further holds that

$$\frac{\partial P_1^*}{\partial \epsilon} = \frac{\phi}{a_1 + \epsilon}, \quad \phi = \frac{b_2 - \beta}{\beta(b_1 + b_2) - b_1 b_2}. \tag{B.8}$$

Note that $\phi > 0$, since $b_1, b_2 < 0$ and $\beta > 0$. Then, the partial derivative of the true underlying cost of agg. 1 is

$$\begin{aligned} \frac{\partial f_1^{\text{true}}(P_1^*)}{\partial \epsilon} &= \frac{\partial}{\partial \epsilon}\left(a_1 \exp(b_1 P_1^*) + c_1\right) \\ &= a_1 b_1 \exp(b_1 P_1^*) \frac{\phi}{a_1 + \epsilon}. \end{aligned} \tag{B.9}$$

Appendix B.1. Incentive under uniform pricing

The profit Π_i which an aggregator makes under UP is equal to

$$\Pi_i = \lambda(P_i^{\text{nom}} - P_i^*) - f_i^{\text{true}}(P_i^*). \tag{B.10}$$

Here, market price λ corresponds to the negative derivative of the aggregator's curve. We aim to find out how the aggregator's profit changes with ϵ. Therefore, we are interested to calculate $\frac{\partial \Pi_1}{\partial \epsilon}$. First,

$$\begin{aligned} \frac{\partial \Pi_1}{\partial \epsilon} &= \frac{\partial}{\partial \epsilon}\left(-(a_1 + \epsilon) b_1 \exp(b_1 P_1^*)\right) \\ &= -b_1 \exp(P_1^* b_1) - b_1^2 \exp(P_1^* b_1)\phi \\ &= -b_1 \exp(b_1 P_1^*)(1 + b_1 \phi). \end{aligned} \tag{B.11}$$

By using the previous results, the derivative becomes

$$\begin{aligned}
\frac{\partial \Pi_1}{\partial \epsilon} &= \frac{\partial \lambda}{\partial \epsilon}(P_1^{\text{nom}} - P_1^*) - \lambda \frac{\partial P_1^*}{\partial \epsilon} - \frac{\partial f_1^{\text{true}}(P_1^*)}{\partial \epsilon} \\
&= -b_1 \exp(b_1 P_1^*)(1 + b_1\phi)(P_1^{\text{nom}} - P_1^*) \\
&+ b_1 \exp(b_1 P_1^*)\phi - a_1 b_1 \exp(b_1 P_1^*)\frac{\phi}{a_1 + \epsilon} \\
&= -b_1 \exp(b_1 P_1^*)(1 + b_1\phi)(P_1^{\text{nom}} - P_1^*) - \phi(1 - \frac{a_1}{a_1 + \epsilon})) \\
&\overset{\epsilon \lll 1}{=} -b_1 \exp(b_1 P_1^*)(1 + b_1\phi)(P_1^{\text{nom}} - P_1^*) \\
&= \underbrace{-b_1}_{>0} \underbrace{\exp(b_1 P_1^*)}_{>0} \underbrace{\frac{\beta b_2}{\beta(b_1 + b_2) - b_1 b_2}}_{>0} \underbrace{(P_1^{\text{nom}} - P_1^*)}_{>0}.
\end{aligned} \tag{B.12}$$

Hence, agg. 1 has an incentive to unilaterally deviate from a truthful offer curve under UP.

Appendix B.2. Incentive under pay-as-bid

The profit which an aggregator makes with PAB is equal to

$$\begin{aligned}
\Pi_1 &= f_1^{\text{offer}}(P_1^*) - f_1^{\text{true}}(P_1^*) \\
&= (a_1 + \epsilon)\left(\exp(b_1 P_1^*) - \exp(b_1 P_1^{\text{nom}})\right) - a_1\left(\exp(b_1 P_1^*) - \exp(b_1 P_1^{\text{nom}})\right) \\
&= \epsilon \exp(b_1 P_1^*) - \epsilon \exp(b_1 P_1^{\text{nom}}).
\end{aligned} \tag{B.13}$$

Calculating the derivative of the profit by ϵ results in

$$\begin{aligned}
\frac{\partial \Pi_1}{\partial \epsilon} &= \frac{\partial}{\partial \epsilon}\left(\epsilon \exp(b_1 P_1^*) - \epsilon \exp(b_1 P_1^{\text{nom}})\right) \\
&= \exp(b_1 P_1^*) - \exp(b_1 P_1^{\text{nom}}) + \epsilon b_1 \exp(b_1 P_1^*)\frac{\partial P_1^*}{\partial \epsilon} \\
&= \exp(b_1 P_1^*) - \exp(b_1 P_1^{\text{nom}}) + \epsilon b_1 \exp(b_1 P_1^*)\frac{\phi}{a_1 + \epsilon} \\
&\overset{\epsilon \lll 1}{=} \underbrace{\exp(b_1 P_1^*) - \exp(b_1 P_1^{\text{nom}})}_{>0}.
\end{aligned} \tag{B.14}$$

Therefore, under PAB agg. 1 has an incentive to unilaterally deviate from a truthful offer curve.

Appendix C. Optimization of residential heating resources

Let $\mathcal{H}$ be the set of the aggregator's residential heating systems, indexed by m. The portfolio is optimized for an upcoming horizon, and $\mathcal{T}$ is the set containing the corresponding timesteps, indexed by t. $T_{m,t}$ denotes the indoor temperature at time step t and household m, and T^{set}_m the ideal temperature. $T_{m,t}$ is allowed to vary within a dead band without causing thermal discomfort. By introducing variables $T^{+}_{m,t}$ and $T^{-}_{m,t}$ as the positive and negative temperature deviations from the deadband respectively, we can relax this constraint as

$$T^{\text{set}}_m - \delta^{-}_m \leq T_{m,t} - T^{+}_{m,t} + T^{-}_{m,t} \leq T^{\text{set}}_{m,t} + \delta^{+}_m. \tag{C.1}$$

Additional constraints on $T^{+}_{m,t}$ and $T^{-}_{m,t}$ are used to prevent excessive temperature deviations, i.e.,

$$0 \leq T^{+}_{m,t} \leq \delta^{\text{lim,+}}_m, \quad 0 \leq T^{-}_{m,t} \leq \delta^{\text{lim,-}}_m. \tag{C.2}$$

The baseline consumption of one thermostatically controlled load is given by

$$P^{\text{base}}_{m,t} = \frac{\alpha_m}{\beta_m}(T_{m,t} - T^{\text{amb}}_t), \tag{C.3}$$

where $\alpha_m = 1/R_m C_m$, and $\beta = \gamma_m / C_m$; C_m is the thermal capacitance, R_m is the thermal resistance, T^{amb}_t is the time-varying outside temperature, γ_m is the coefficient of performance, and P^{n} is the nominal power. Using data from the Ecogrid 2.0 project [36], R is found to be approximately 24 °C/kW, C equal to 1.05 kWh/°C, and P^{n} 1.68 kW. This is in agreement with estimates provided in [50]. If $P_{m,t}$ is the power consumption at time step t, then the power constraints are expressed by

$$0 \leq P_{m,t} \leq P^{\text{n}}_m. \tag{C.4}$$

State $X_{m,t}$ represents the energy content of the thermal battery model. If ΔT is the normalized time step ($\Delta T = 1$ corresponding to one hour), then the evolution of $X_{m,t}$ is described by

$$X_{m,t+1} = X_{m,t}\ a^{\mathrm{d}}_m + \Big[P_{m,t} + \gamma_m (T^{\mathrm{amb}}_t - T_{\mathrm{r},m})\Big]\ \Delta T, \tag{C.5}$$

where the self-discharge rate a^{d}_m is equal to $1 - \alpha_m\ \Delta T$ and for notation simplicity $\gamma_m = \alpha_m / \beta_m$. The energy constraints of the thermal battery model require that $-S^-_m \leq X_{m,t} \leq S^+_m$, where the energy limits are given by

$$S^+_m = C_m\ \delta^+_m, \qquad S^-_m = C\ \delta^-_m. \tag{C.6}$$

We relax the constraints of the energy limits in a similar manner as (C.1) on temperature, i.e.,

$$-S^-_m \leq X_{m,t} - X^+_{m,t} + X^-_{m,t} \leq S^+_m. \tag{C.7}$$

The introduced non-negative variables $X^+_{m,t}$ and $X^-_{m,t}$ have an equivalent interpretation to $T^+_{m,t}$ and $T^-_{m,t}$, and they express temperature deviations outside the dead band in energy terms. We again impose additional constraints on deviations $X^+_{m,t}$ and $X^-_{m,t}$, such that

$$0 \leq X^+_{m,t} \leq S^{\mathrm{max}}_m \qquad 0 \leq X^-_m \leq S^{\mathrm{min}}_m. \tag{C.8}$$

Parameters S^+_m and S^-m are calculated as

$$S^{\mathrm{max}}_m = C\ \delta^{\mathrm{max}}_m, \qquad S^{\mathrm{min}}_m = C\ \delta^{\mathrm{min}}_m. \tag{C.9}$$

The aforementioned parameters are summarized in Table C.3. R and C are drawn from normal distributions, with a mean value equal to the one obtained through our experiments. To avoid unreasonable values for the nominal power, households nominal power is chosen as a function of R and C but with a slight randomness, represented as a normal distribution. Given a day's known prices, and assuming perfect day-ahead ambient temperature forecasts, the total aggregator cost be

Table C.3: Parameters of residential heating loads

Parameter	Description	Value or distribution
T^{set} (°C)	Temperature set-point	21
C (kWh/°C)	Thermal capacitance	$\mathcal{N}(1.05, 0.1)$
R (°C/kW)	Thermal resistance	$\mathcal{N}(24, 2)$
P^{n} (kW)	Nominal power	$1.68RC/25.2 + \mathcal{N}(0, 0.2)$
δ^{+}, δ^{-} (°C)	Temperature deadband	1
$\delta^{\text{lim,+}}, \delta^{\text{lim,-}}$ (°C)	Max temperature variation	2

found by solving the following optimization problem, with $\mathcal{W} = \{P_{m,t}, X_{m,t}, X^{+}_{m,t}, X^{-}_{m,t} \mid m \in \mathcal{H}, t \in \mathcal{T}\}$ representing the set of decision variables

$$\min_{\mathcal{W}} \quad \sum_{m\in\mathcal{H}} \sum_{t\in\mathcal{T}} (\lambda_t P_{m,t} + \rho X^{-}_{m,t} + \rho X^{+}_{m,t}) \Delta T \tag{C.10a}$$

$$\text{s.t.} \quad 0 \leq P_{m,t} \leq P^{\text{n}}_{m}, \qquad \forall m \in \mathcal{H}, \forall t \in \mathcal{T} \tag{C.10b}$$

$$X_{m,t+1} = X_{m,t}\, a^{\text{d}}_{m} + \left[P_{m,t} + \gamma_m (T^{\text{amb}}_{t} - T^{\text{set}}_{m})\right] \Delta T, \qquad \forall m \in \mathcal{H}, \forall t \in \mathcal{T} \tag{C.10c}$$

$$X_{m,0} = X_{m,|\mathcal{T}|} = 0, \qquad \forall m \in \mathcal{H} \tag{C.10d}$$

$$- S^{-}_{m} \leq X_{m,t} - X^{+}_{m,t} + X^{-}_{m,t} \leq S^{+}_{m}, \qquad \forall m \in \mathcal{H}, \forall t \in \mathcal{T} \tag{C.10e}$$

$$0 \leq X^{+}_{m,t} \leq S^{\max}_{m},\ 0 \leq X^{-}_{m} \leq S^{\min}_{m}, \qquad \forall m \in \mathcal{H}, \forall t \in \mathcal{T} \tag{C.10f}$$

$$\sum_{m\in\mathcal{H}} P_{m,t} \leq P^{\text{lim}}, \qquad \forall t \in \mathcal{T}, \tag{C.10g}$$

where λ_t is the hourly day-ahead price value in DKK/kW, ρ is the hourly thermal discomfort price expressed in DKK/kWh, which is set equal to 1 DKK/kWh.

Appendix D. Optimization of a fleet of EVs

Let $\mathcal{E}$ be the set of the aggregator's EVs, indexed by k. The portfolio is optimized for an upcoming horizon, and $\mathcal{T}$ is the set containing the corresponding timesteps, indexed by t. $\mathcal{D}_k \subseteq \mathcal{T}$ is the set that contains the timesteps when EV k is plugged in. $P_{k,t}$ and $SOC_{k,t}$ represent the charging power and SOC of EV k at time t, respectively. t^{arr}_{k}, t^{dep}_{k} and SOC^{arr}_{k} denote the arrival time, departure time and SOC during arrival of EV k. λ_t is the day-ahead market price at time t, η_k is the efficiency of EV k, and ΔT is the time step length. E_k^{kWh} and $P_k^{\max}$ are the energy storage capacity and nominal charging power of EV k, respectively. With $\mathcal{M} = \{P_{k,t}, SOC_{k,t} \mid k \in \mathcal{E}, t \in \mathcal{T}\}$ representing the set of decision variables, the optimization problem is formulated as

$$\min_{\mathcal{M}} \quad \sum_{k\in\mathcal{E}} \sum_{t\in\mathcal{T}} \lambda_t P_{k,t} \Delta T \tag{D.1a}$$

$$\text{s.t.} \quad 0 \leq P_{k,t} \leq P_k^{\max}, \qquad \forall k \in \mathcal{E}, \forall t \in \mathcal{D}_k \tag{D.1b}$$

$$P_{k,t} = 0, \qquad \forall k \in \mathcal{E}, \forall t \notin \mathcal{D}_k \tag{D.1c}$$

$$SOC_{k,t+1} = SOC_{k,t} + \frac{\eta_k}{E_k^{\text{kWh}}} P_{k,t} \Delta T, \qquad \forall k \in \mathcal{E}, \forall t \in \mathcal{D}_k \tag{D.1d}$$

$$SOC_{k,t_k^{\text{dep}}} = 1, \qquad \forall k \in \mathcal{E} \tag{D.1e}$$

$$SOC_{k,t_k^{\text{arr}}} = SOC_k^{\text{arr}}, \qquad \forall k \in \mathcal{E} \tag{D.1f}$$

$$SOC_k^{\text{arr}} \leq SOC_{k,t} \leq 1, \qquad \forall k, \forall t \in D_k \tag{D.1g}$$

$$\sum_{k\in\mathcal{E}} P_{k,t} \leq P^{\text{lim}}, \qquad \forall t \in \mathcal{T}. \tag{D.1h}$$

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