Capacity limitation based local flexibility market for congestion management in distribution networks: Design and challenges

Electrical Power and Energy Systems 156 (2024) 109742

Contents lists available at ScienceDirect

International Journal of Electrical Power and Energy Systems

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

Capacity limitation based local flexibility market for congestion management in distribution networks: Design and challenges☆

Nima Mirzaei Alavijeh [a,*], David Steen [a], Le Anh Tuan [a], Sofia Nyström [b]

[a] Department of Electric Power Engineering, Chalmers University of Technology, 412 96, Gothenburg, Sweden
[b] Ramboll, Vädursgatan 6, Box 5343, 402 27, Gothenburg, Sweden[1]

A R T I C L E I N F O

Keywords:
Local flexibility market
Congestion management
Demand-response
Distribution system operator
Baseline

A B S T R A C T

In this paper, five of the main design challenges of local flexibility markets (LFMs) for congestion management are identified and discussed based on desirable market properties from economics theory and literature review. The five main design challenges are low market liquidity, reliability, baselines, forecast errors at low aggregation levels, and the high cost of measurements. A comprehensive capacity-limitation based LFM design has been proposed to address the challenges and a simulation example is presented to illustrate the design. The proposed design facilitates market participants' decision making by design elements that improve market liquidity, reliability and handling of forecast errors. Moreover, a new capacity limitation product is proposed that is not defined with respect to a baseline and does not require sub-meter measurements leading to lower costs and conflict-of-interest in delivery validation. Generic algorithms are also proposed for calculating utility and cost of the flexibility product. The proposed design and discussions can contribute to improving the interdisciplinary area between engineering and economics while helping policy-makers and LFM stakeholders to further understand the problem from a multi-dimensional perspective.

1. Introduction

Three main trends in the current electricity system transition are: increasing penetration levels of stochastic renewable energy sources (RES), electrification of other sectors such as transport [1] and heating, and a more active control of distributed energy resources (DERs) that can increase the load concurrency [2]. These trends can cause challenges such as congestion or voltage-limit violations in the electrical distribution grids. As the distribution system operators' (DSOs') core responsibility is providing a reliable, secure, and efficient distribution network [3], addressing congestion and voltage-limit violations are essential. Additionally, alleviating such local issues can support the transition in the energy system by allowing a faster and larger electrification and penetration levels of DERs. If these issues are alleviated by cost efficient methods, the transition costs related to the need for grid reinforcements can be reduced [4].

There are different solutions proposed for these challenges including grid reinforcements, market-based solutions, innovative tariff designs, rule-based approaches, active network management, or comprehensive methods including a mixture of solutions [5,6]. The market-based solutions have been recognized and promoted by regulators and other actors in Europe. For example, the European Parliament has promoted market-based solutions in Article 32 of the Electricity Market Directive (2019/944) of the EU clean energy package [3]. The Association of European Energy Exchanges has mentioned market-based solutions as the most efficient approach to match the supply and demand for flexibility [7]. Moreover, market-based solutions are identified as being part of the solution by Council of European Energy Regulators [6].

Local flexibility markets (LFMs) are an example of market-based solutions. However, the design of these markets are accompanied by various challenges. This paper aims to identify the common challenges in the design of LFMs for alleviating congestion in distribution networks and propose solutions in the form of a comprehensive market design and an illustrative simulation example.

To identify the design challenges and their importance, an overview of desirable market properties in economics theory is essential. Mechanism design is a branch of economics with applications in different contexts such as agreements, voting, privatization, and markets. This branch focuses on starting from suitable outcomes of an economic institute and asks how it can be designed to achieve the outcomes.

☆ The work leading to this paper is from work-package 2 of FLEXIGRID project that is funded by the European Commission's Horizon 2020 Framework Programme under grant agreement no. 864048.

* Corresponding author.
E-mail address: nima.mirzaei@chalmers.se (N. Mirzaei Alavijeh).

[1] Most of the work was conducted under affiliation RISE Research Institutes of Sweden, Sven Hultins plats 5, 412 96, Gothenburg, Sweden.

https://doi.org/10.1016/j.ijepes.2023.109742
Received 17 March 2023; Received in revised form 27 November 2023; Accepted 21 December 2023
Available online 4 January 2024

Table 1
Negatively-impacted desirable market properties as a result of the common LFM design challenges. Abbreviations are IC: Incentive compatibility, and GR: Group rationality.

LFM design challenges	Impacted market property	Reason
Low market liquidity	IC	Potential gaming
	GR	Uncertainties in supply/demand
Reliability concerns	IC	Potential low liquidity due to reliability concerns leading to potential gaming
	GR	Uncertainties in supply/demand hindering market access for risk averse actors
Baselines	IC	Potential gaming through baselines
	GR	Conflict of interests, and transparency issues
Forecast errors	GR	Extra costs due to failures in delivery, or wrong estimations for the required/available service quantity
High measurement and ICT costs	GR	Extra costs for sub-meter measurement and communication besides higher system complexity

The general desirable properties of a mechanism in the context of local markets are presented in [8,9], including:

- Efficiency: The mechanism should maximize the social welfare of its participants considering their revealed preferences.
- Incentive compatibility: The mechanism should be designed to incentivize the participants for declaring their true preferences (e.g., the true cost/utility).
- Budget balance: The mechanism should be designed in a way that its operator would have neither deficit nor excess in its financial balance.
- Group rationality: A desirable mechanism should be designed in a way that no individual or group of participants would be willing to separate from the market to obtain larger benefits. The result of such a property is the stability of the mechanism.

Since LFMs are economic mechanisms, these desirable properties can be used for explaining how design challenges can affect the performance of these mechanisms through impacting these desirable properties. Additionally, these properties can support analyzing the available LFM designs in the literature to identify the gap in addressing these challenges.

1.1. Common challenges in LFM design

This subsection identifies common LFM design challenges and their impact on the desirable market properties. The challenges are identified by reviewing proposed LFM designs, experiences from different projects, and workshops with DSOs in the FlexiGrid project [10]. The challenges below are commonly mentioned:

1. Low market liquidity
2. Reliability concerns
3. Challenges regarding defining baselines for a baseline-based flexibility product
4. Forecast errors due to low aggregation levels
5. The high costs concerning the need for extra measurements and information and communication technology (ICT) infrastructure.

Low market liquidity is commonly mentioned in various studies such as [11–15]. The low liquidity can be due to the geographical limit of the local markets, and a lack of available flexible resources in the transition phase of end-users becoming flexible and LFMs being adopted [14]. A less liquid market is less competitive, and more prone to instability [16] and market manipulation [17]. Thus, if the LFM as a whole can be seen as a mechanism, the desirable market property of incentive compatibility can get affected as a result of low market liquidity. Low liquidity can also lead to uncertainties in supply or demand that can affect the willingness to engage and thus negatively impact the group rationality property. While low liquidity can impact incentive compatibility and group rationality, efficiency would not be affected as it is defined based on declared costs/utilities. These points are summarized in Table 1.

The reliability challenge is partially linked to low liquidity and security of supply for flexibility which is crucial for DSOs to ensure a reliable, secure, and efficient distribution network as their core responsibility [3]. The local markets are especially presented as a substitute to grid reinforcements [18] that cannot be implemented over-night if there is a lack of flexibility. On the other hand, the flexibility service providers (FSPs), including property managers and real estate owners, can have reliability concerns for return of investments considering a lack of (flexibility) demand and uncertain revenue streams [12,19]. Moreover, FSPs can be risk averse as flexibility provision can negatively affect the comfort of their tenants [18,20]. Low liquidity and security of supply/demand can affect market reliability and hinder market access for more risk averse actors. Consequently, as summarized in Table 1, it impacts the group rationality property as it can lead to participants leaving the market or not being willing to join. Moreover, market liquidity and thus incentive compatibility of the market can be impacted if there are not sufficient incentives and reliability for the participants in the local markets.

The challenges with baseline are mentioned in various sources such as [11,21,22]. [21] evaluates different methods for defining baseline and argue why baselines are not suitable for LFMs based on four criteria of transparency and simplicity, inclusive use of flexibility, manipulation-proofness, and compatibility with continuous and smart control of flexibility resources. They conclude that the baseline-based flexibility products are not aligned with active participation of distributed energy resource (DER) owners in different markets because finding admissible days for calculating the baseline would be more challenging. Moreover, they highlight that these products can cause uncertainty, complexity, potential market manipulations, and conflict of interests between the stakeholders. As presented in Table 1, the baselines, if not coordinated properly, can impact the incentive compatibility due to potential market manipulations, and the group rationality by introducing uncertainty, conflict of interests, and transparency issues.

The forecast error challenge can be due to a smaller aggregation at local levels [23]. The inaccuracy of forecasts can cause issues for defining baselines in an LFM [21,24], or in forecasting the behavior of end-users [22] for a cost-efficient delivery of the promised service. The forecast errors can lead to higher costs for all the stakeholders. For example, they can cause failures in delivery, or wrong estimations for the required/available service quantity. This can lead to penalties or over/under procurement. The extra costs may impact the group rationality because the participants may choose to not obtain or leave the market. This is summarized in Table 1.

The last challenge is the potential need for extensive measurements and investments in ICT platforms required for validating the delivery and communications between the market participants. This challenge has been raised in discussions with DSOs in the project's consortium, and a market design that requires fewer measurements is preferred for monetary and complexity reasons. Similar to the forecast error challenge, the extra cost and the complexity can impact the group rationality property of the LFM mechanism (Table 1).

1.2. Related LFM designs in literature and the gap

Considering the above-mentioned challenges and their importance, the gap in related studies addressing these challenges is identified. These studies and the gap is explained in this section.

To address the liquidity and the reliability challenges, two groups of approaches are identified in the literature. The first group paves the way for a higher liquidity and reliability while the second is focused on preventing the potential consequences of low liquidity such as market manipulations.

Belonging to the first group, availability/reservation payments and long-term contracts have been well-known as ways of securing supply and incentivizing investments (in flexible assets). [19] have categorized the reservation payments as a controversy in LFMs and discuss its advantages and disadvantages. In our previous work [25], we had considered long-term reservations based on a mixed-price of reservation and activation prices; however, the mixed-price approach can increase the market complexity while complicating interpretation of the clearing prices. Moreover, linkage between the reservation and activation payments/markets are to be explored further. [26] have proposed a "Right-to-Use" option as a flexibility reservation due to uncertainties in their day-ahead (DA) flexibility market. This suggestion, although being helpful for handling DA uncertainties, would not match the long-term planning horizon of DSOs and potential investors in flexible assets. Therefore, an interconnected long-term reservation and short-term activation with a simpler pricing approach that establishes a more robust linkage between the two markets would be beneficial.

From the second group, incentive compatible payment allocation methods such as Vickrey–Clarke–Groves (VCG) can be utilized to prevent market manipulation. However, VCG is not budget balanced and can lead to practical challenges. One-sided VCG is suggested as a potential solution in [27]. However, one-sided VCG is not individually rational for the DSOs. In theory, it can lead to DSOs paying more than their declared willingness and thus leaving or not adopting the market.

In contrast to issues with individual rationality and budget balance, issues with incentive compatibility can be improved by measures that increase the liquidity and preventing market manipulations. Some examples filling this gap are long-term availability payments and multi-bids [28] for the first group of approaches, and market monitoring, anti-trust law, and price caps [19] for preventing market manipulations as the second group.

The challenges related to baseline-based flexibility products are discussed and tried to be addressed in [21,27] by proposing a new class of products called capacity limitation based products. A capacity limitation (CL) product is a service that keeps the consumption/generation below or above a certain limit. However, [27] mention that functionality of their CL product is dependent on truthful declaration of assets by FSPs. For example, an FSP can provide the limitation of using its heat pump with respect to nominal capacity of the HP. However, the FSP could instead switch on an undeclared electric heater. Since the validation of delivery is done based on sub-meter measurements on the declared devices, the FSP would get paid for providing flexibility although it had not contributed to reducing the congestion. Moreover, the proposed CL product seems to require sub-meter measurements for all flexible assets that can lead to higher costs and complexity for validation of the service delivery. Therefore, a CL product design that is not dependent on truthful declaration of DERs capacity can facilitate delivery validation. In addition, if the product requires less measurements and thus less ICT-related costs, the fifth challenge can be addressed.

From a mechanism design perspective, the forecast errors at low aggregation levels have been addressed diversely in the literature. For example, Enera's market allows its continuous auction until 5 min before the delivery time [29]. This approach can allow improvement of forecasts as getting closer to the delivery time but it can come at the expense of market efficiency losses as continuous auctions have lower allocation efficiency compared to call-auctions [30–32]. Bouloumpasis et al. [25], IREMEL [33], InterFlex [34], INTERFACE [35] markets, and [36] take another approach and include an intraday/real-time market [29]. Considering these different approaches, it is beneficial to assess what suits better for reducing the impact of the forecast errors.

1.3. Paper contributions

Based on the five identified challenges and the solution gap, a comprehensive market design addressing the challenges would be valuable. To the best of our knowledge, there has not been any proposed design that has comprehensively considered all the mentioned challenges. Therefore, the main contributions of this work are:

- Identification of the LFM design challenges including low market liquidity, reliability concerns, baseline issues, and high ICT costs
- Enhancement of different available solutions to these challenges to formulate a practical and comprehensive LFM design.
- Proposal of generic algorithms to calculated the cost and utility of flexibility in the proposed LFM design

By identifying these challenges and proposing an improved market design, this work aims to advance the understanding and practical implementation of LFMs.

1.4. Paper organization

In the rest of the paper, a comprehensive proposal for the market design is presented in Section 2 and the different choices made in the design are elaborated. An illustrative simulation example is going to be provided to facilitate understanding of the design. The advantages and disadvantages of the design and future work are discussed in Section 3. Conclusions are provided in Section 4.

2. Local flexibility market design: How the market works

In this section, initially, an overview of the proposed LFM design is presented. Subsequently, design modules are elaborated comprising market framework, clearing algorithm and bids, as well as settlement and payment allocation method. The illustrative simulation example is provided in conjunction with the aforementioned modules to facilitate comprehension of the design. The example setup is explained in Appendix.

The overview of the proposed design is presented in Fig. 1. The traded products are CL products that result in FSPs maintaining their net-loads under a cap, or above a floor, depending on whether a congestion event is driven by an excess of demand or generation. The net-load (P^{net}) is defined in Eq. (1) for each FSP where P^{con} is the consumed power and P^{gen} is the generated power. Therefore, negative P^{net} represents injections, and positive values extractions. Additionally, an FSP can either be an aggregator representing multiple end-users, or an individual end-user. In the case of aggregators, CL product restricts the aggregated net-loads while in the case of individual end-users, it is the net-load of the end-user that is restricted. The product design is further explained in Section 2.1.2.

$$P_t^{net} = P_t^{con} - P_t^{gen}, \quad where \quad P_t^{con}, P_t^{gen} \geq 0 \tag{1}$$

The proposal includes three markets (Fig. 1). The long-term market aims to compensate flexibility product availability, akin to capacity markets in the electricity trading domain. The short-term market serves as a market for trading the flexibility product. Finally, the continuous adjustment market provides an opportunity for adjustments to the traded quantities within the short-term market. The first two markets are call-auctions, while the third market is a continuous auction. Call-auctions involve aggregating, sorting, and clearing the entire market at once after gate closure, while continuous auctions match bids instantaneously until gate closure [31]. The organization of market stages are explained in Section 2.1.3. All three markets are auctions with the objective of social-welfare maximization. The market clearing algorithm is presented in Section 2.2.4. Pay-as-bid (PAB) is chosen as the payment allocation method that is discussed in Section 2.3. The subsequent sections elaborate the rational behind these design choices, and discuss solutions to the identified design challenges. The locations of the solutions are illustrated in Fig. 2.

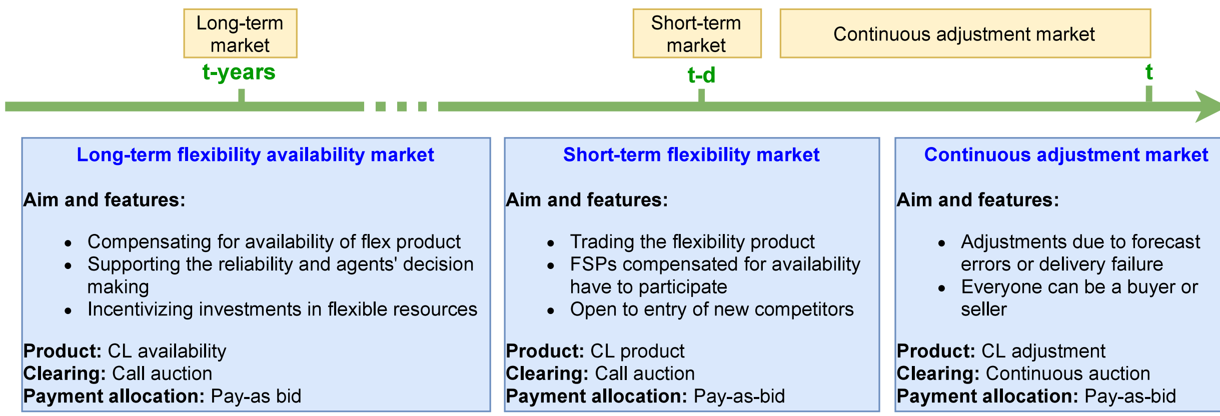


Fig. 1. Overview of the market stages.

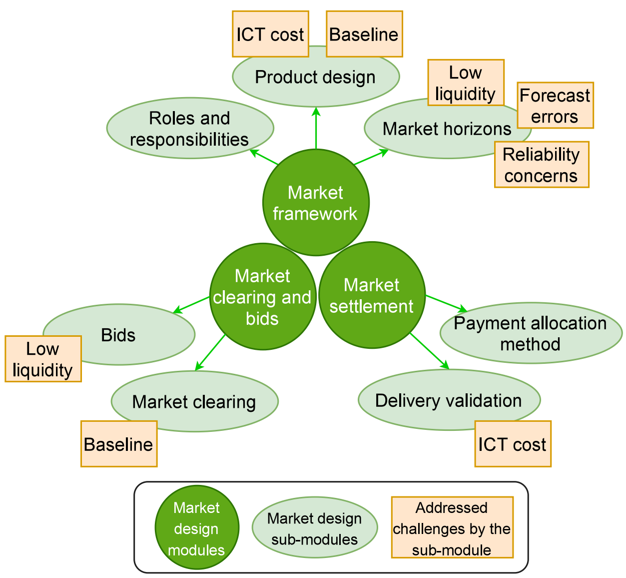


Fig. 2. The link between the LFM design challenges and the location of their solutions in the market design.

2.1. Market framework

Market framework clarifies the roles and responsibilities of different actors, traded products, and the three market stages.

2.1.1. Roles and responsibilities of market participants

Three main roles are foreseen in an LFM:

- Flexibility seller: FSPs are the sellers and can be aggregators, or individual consumers/prosumers.
- Flexibility buyer: DSO is the buyer that evaluates the situation with congestion forecasts and requests flexibility if needed. In close-to-real-time, the DSO can purchase or sell-back flexibility in the adjustment market depending on status of its grid.
- Market operator: The market operator is a neutral, independent party that manages the market, receives asks and bids, and conducts clearing and settlement.

2.1.2. Product design

Two types of CL products are proposed depending on if congestion is demand- or generation-driven. A demand-driven congestion occurs when the total power extraction of end-users causes overloading of a grid component. For generation-driven congestion, the total power injection causes the overloading besides potential voltage-limit violations. Consequently, the proposed CL products are:

- CL-cap (for demand-driven congestion): Enforces FSPs to keep their net-load under a certain cap.
- CL-floor (for generation-driven congestion): Enforces FSPs to keep their net-load above a certain floor.

The CL-products are defined using net-load (p^{net}) and subscribed connection capacity ($\overline{P}^{\text{net}}$) of FSPs. As shown in Eq. (2a), by selling q kWs of CL-cap, an FSP should restrict its p^{net} by q kWs with respect to $\overline{P}^{\text{net}}$. A similar logic is presented in Eq. (2b) where the FSP keeps its p^{net} above a certain floor. Fig. 3 illustrates the products for three FSP types: consumer, prosumer, and generator. p^{net} is always negative for generators (Eq. (1)). So, if a flexible generator has sold a CL-cap, it might need to increase its generation that contributes to relieving a demand-driven congestion. p^{net} is always positive for consumers. Therefore, if a flexible consumer has sold a CL-floor, it might have to increase its consumption that contributes in relieving a generation-driven congestion.

$$p_t^{net} \leq \overline{P}^{\text{net}} - q_t^{CLcap} \tag{2a}$$

$$p_t^{net} \geq -\overline{P}^{\text{net}} + q_t^{CLfloor} \tag{2b}$$

In countries where subscribed connection capacity contracts do not exist, they can be calculated using historical data or auctions. A similar approach is used in the evolvement of emission permit allocations for the European Emission Trading Scheme [37].

From the illustrative simulation example, Fig. 4 shows a deterministic forecast for loading of a transformer during a day. The transformer active power rating is 150 kW. A congestion is expected at Hour 7336 with an active power loading of 158 kW and the DSO can buy CL-cap on the market to address the issue. Such a small overloading over a short period can probably be tolerated by the transformer and might not lead to a large loss of life either. However, other costs such as penalties to the upstream grid owner can still be imposed on the DSO that can be avoided if the service is procured. The provided simulation example is solely designed for illustrating the design as simple as possible. In real-life, each DSO need to examine where to put the threshold for purchasing the service depending on factors such as the cooling system of their components, protection system thresholds, and penalties from the upstream grid owner. In this example, the quantity of the CL product for the DSO is calculated with respect to the sum of subscribed connection capacities located downstream of this transformer, i.e., 230 kW. For example, by buying 80 kW of CL the DSO can be sure that the loading stays below the transformer active power rating, i.e., 150 kW. An FSP, if cleared for x amount of CL, has to keep its net-load below the new imposed cap that is calculated with respect to its connection capacity.

The proposed product design has several advantages: (i) calculation of its quantity is not with respect to a baseline and instead, is calculated with respect to the static and transparent values of connection

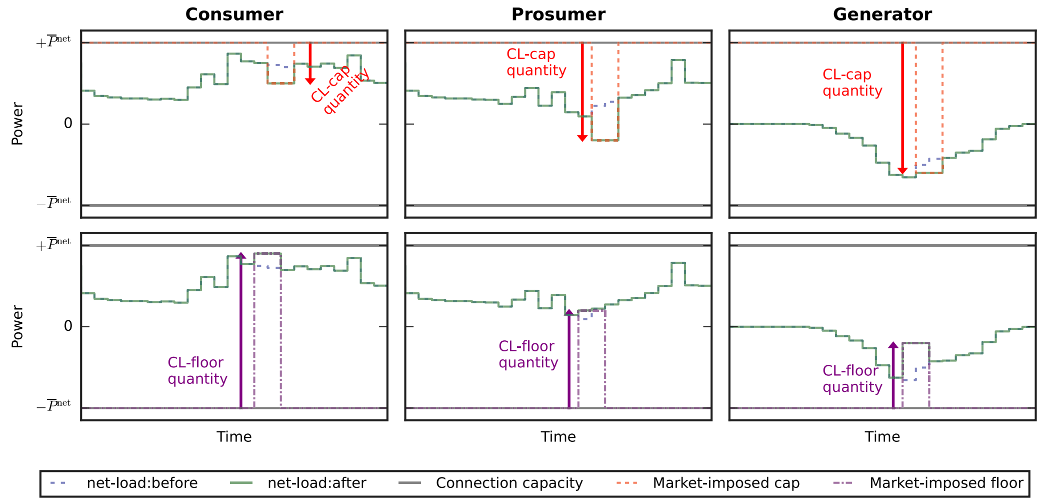


Fig. 3. Conceptual illustration of capacity limitation products for different type of grid users. CL-cap is for demand-driven congestion and CL-floor for generation-driven congestion.

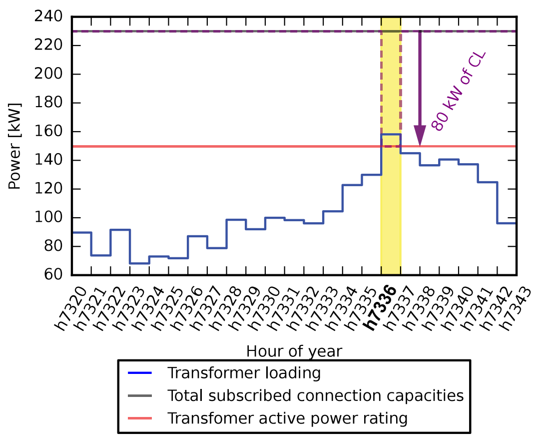


Fig. 4. Illustrating CL-cap product based on the simulation example. Congestion is expected at h7336.

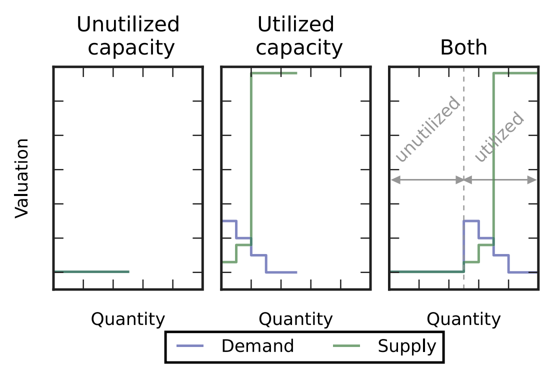


Fig. 5. Heterogeneity of the CL product.

capacities that can provide a certainty for DSOs regarding the cap for cumulative loading after procurement; (ii) the product is technology neutral because it does not impose the method for changing the net-load. FSPs, therefore, can find the most cost-efficient method; (iii) it hinders the potential manipulation by not declaring flexible assets (mentioned in [27]) because it is defined and verified by the net-load and is not dependent on the declaration of flexible assets; and (iv) it does not require sub-metering and thus leads to lower ICT-related costs.

On the other hand, the CL product is accompanied by challenges including its potential heterogeneity, and consequently complexities in bidding and clearing algorithms. CL product is most likely not homogeneous. Oxford dictionary of economics [38] defines heterogeneous goods as "Goods which differ in specifications or quality, or bear different brand names which convey information to customers". Although the specification and the unit of the CL product is consistent – limiting connection capacity by 1 kW –, its "quality" varies. The quality of a CL product can be defined based on its purpose which is changing the net-load of FSPs and thus reducing congestion. For instance, in Fig. 4, the initial 72 kW of CL has no impact on the net-load of FSPs because it only covers their unused connection capacity. Consequently, this segment offers a low utility to the DSO. The remaining 8 kW, however, exhibit higher quality as they alleviate congestion and provide greater utility to the DSO. Homogeneity is a fundamental assumption in microeconomics, and most supply and demand models "simply assume that all goods in the market are identical" [39]. Therefore, the law of demand does not necessarily need to hold in the case of a heterogeneous good such as the CL product. Fig. 5 illustrates the expected marginal utility and cost curves for when utilized and unutilized capacities were traded separately versus when they are traded together. When traded separately, marginal utility and cost for unutilized capacity are expected to form a flat curve since they do not affect FSPs' behavior. The marginal utility and cost for utilized capacity are expected to have a downward and upward slope, respectively. This is because as more is purchased by the DSO, the overloading would be lower, and as more is sold by an FSP, the deviation from its cost-optimal behavior grows. When these two "quality" classes are traded together, the demand curve of the product becomes heterogeneous, resulting in a non-downward sloping demand curve for the DSO. This potential heterogeneity leads to complexities in the bidding and clearing algorithms. The calculation of marginal utility and cost curves are discussed in Section 2.2.1. Furthermore, the division of the product into two quality classes indirectly introduces a declared baseline through the unutilized capacity class. These indirect baseline declarations can be managed through an internalized automated negotiation process within the market clearing algorithm as explained in Section 2.2.4.

2.1.3. The organization of market stages

To have a more comprehensive market design, three interconnected market stages are proposed: long-term, short-term, and close-to-real time. An overview of the stages are provided in Fig. 1. The long-term market is for availability remunerations for flexibility services, contributing to reliability, decision making of the agents, as well as increasing the liquidity by incentivizing investments in flexible technologies. The short-term market acts as a market for trading the service

Table 2
The suitability-comparison of continuous and call-auctions for the adjustment market.

Compared aspect	Reference	Auction type	
		Continuous	Call
Information efficiency	[30,31]	+	–
Suitability for risk-averse actors	[30]	+	–
Liquidity	[31,32]	–	+
	[40]	+	–
Suitability for small actors	[31,32]	–	+
Market power resilience	[31]	–	+
Cost of late scheduling	[30]	+	–
Social welfare	[30–32]	–	+
Computational burden	[32]	–	+

if needed, and the continuous adjustment market is for trading adjustments to the traded quantities in the short-term market. Adjustments might be needed due to forecast errors or anticipated delivery failures. Pay-as-bid is chosen as payment allocation method for all the stages and the reasoning is provided in Section 2.3. The exact gate opening and closing times need to be decided considering factors such as investments lead time, timelines of wholesale and balancing markets, and operation routines of market participants. These factors can differ between countries or regions.

In the long-term market, the DSO sends an expected time period, a location, a quantity for the product that might be required, as well as a demand curve reflecting its willingness to pay for the availability of the product. Moreover, the DSO can send an activation price cap when the long-term market is opened which would be communicated to FSPs. The cleared FSPs in this market stage will be compensated to be available in the short-term market. Therefore, the compensated FSPs are obliged to participate in the short-term market while their offering prices should be lower than the communicated activation price cap. After the short-term market is cleared, the cleared quantities are binding. However, the participants can make adjustments to these cleared quantities in the continuous adjustment market where all the participants can be a buyer or a seller.

There are two main auction-types available for each stage: call and continuous auctions. However, as explained in the introduction, different auction types have been proposed for LFMs. Therefore, a literature review has been conducted to contribute to this controversy in what type of market suits best for each stage.

The two auction types are compared from different aspects. The aspects and the summary of results are presented in Table 2. Information efficiency is the possibility for the instantaneous transfer of newly arrived information to the market [31,41]. Continuous markets allow participants to correct their bids and trade as soon as possible when they anticipate benefits [30]. However, call-auctions are cleared at a specific time and cause delays in transferring information and trading [31]. Continuous markets provide a better environment for risk-averse actors because these actors want to minimize the risks related to imbalances as soon as possible [30]. DSOs can be risk-averse actors since their core business is to guarantee a reliable supply of power. Regarding the liquidity, there are arguments both for and against the two market types. [31] argue that call-auctions can lead to higher liquidity as they collect all the bids and clear them once at the end of the trading session. Moreover, a study on the intra-day market in Germany has shown that the addition of call-auctions has lead to a higher liquidity and market depth [32]. On the other hand, [40] argue that the liquidity can be higher in a continuous auction as it offers a fast trade execution. Call-auctions are to be more suitable for small actors and more resilient to market power. Call-auctions provide benefits for small players without the capability of continuous 24/7 trading [32]. On the other hand, continuous auctions benefit the large actors since they have a better return on information costs and therefore can to lead entry barriers and market power practices [31,41]. Continuous markets can be more suitable for the actors having costs related late rescheduling as they can communicate and trade corrections as soon as possible [31]. Storage units, and demand response, especially from large industrial flexible demands are examples of such actors. Call-auctions produce a larger social-welfare compared to continuous markets [30–32]. This is because call-auctions are cleared after all offers and bids are collected compared to continuous auctions that bid matching is done instantaneously. In call-auctions, the dedicated computers for market clearing can be allocated only for a certain period of time [32] while continuous auctions require a dedicated computer for the whole adjustment period to match the bids.

To conclude, there are many arguments in favor of call-auction markets and their suitability for local flexibility trading except for the adjustment market where the purpose is corrections and thus information efficiency and minimizing risks for DSOs are essential. Therefore, call-auctions have been chosen for the long-term and short-term markets, and continuous auctions for the adjustment market.

2.2. Market clearing, bids and offers

The market clearing algorithm and the structure of bids and offers are crucial components of any market design. In this section, first, the structure of bids and offers is explained. Subsequently, probabilistic algorithms are proposed for calculating the utility and cost associated with the CL product for both DSOs and FSPs. It should be noted that the focus of this discussion is solely on the algorithms used to compute utility and cost, while analyzing bidding strategies employed by market participants fall outside the scope of the present study. For the sake of the illustration example, simplistic bidding strategies have been considered. Finally, the clearing formulation of the proposed market is explained.

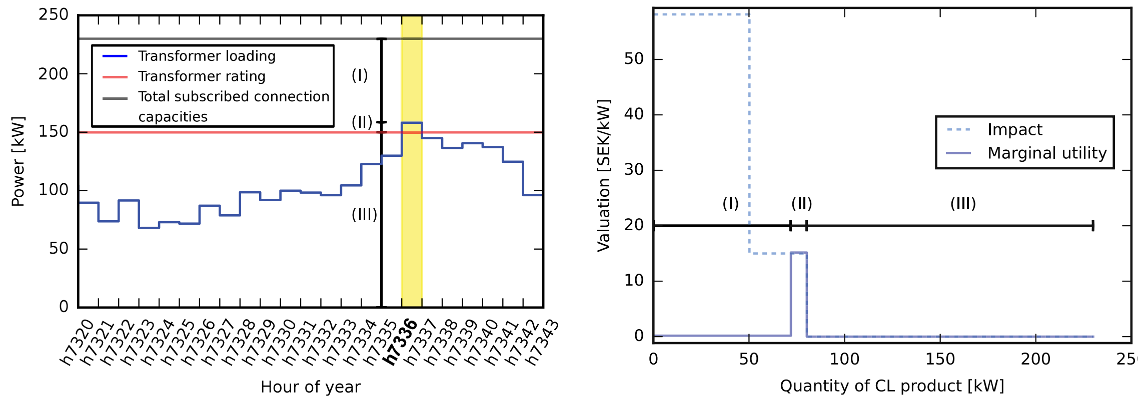
2.2.1. Bids and offers structure

In the proposed structure, the participants declare their cost/utility curves by submitting multi-bids. A multi-bid includes multiple sub-bids. Sub-bids can be accepted simultaneously and are not mutually exclusive. An example of a bid from an agent is shown in Table 3. Here, term bid is used for both requests from a DSO and offers from FSPs. A bid from an agent should include the ID of the agent, the date and the hour the bid is corresponding to (t). The sequence number of the sub-bid (g) indicates the place of the sub-bid on the agents' cost/utility curve. The first sub-bid ($g0$) represents the unutilized capacity declared by buyer and sellers. The bids also include the location code in which the service is requested or offered (l), the quantity of the CL product (q), and the valuation of the bid (u). Depending on the market stage, the valuation represents the cost/utility for availability or activation of the product. The valuation for $g0$ can be a predefined fixed value that represents the connection capacity fee paid by end-users.

The multi-bid setting is chosen as it can support market efficiency by allowing the division of declared quantities into smaller quantity-price pairs leading to an improved bid matching for market participants [28]. [28] also mentions that enabling multi-bids in a low competition situation can lead to an increase in the offered quantities over time (compared to a single-bid scheme). Additionally, [25] suggest that submitting bid-curves can facilitate clearing larger quantities of flexibility in case flexibility resources are limited. These advantages contribute to addressing the low liquidity and the reliability challenges.

2.2.2. DSO's utility from CL product

This subsection discusses the utility from CL-cap product across different market stages. In the long-term market, utility can be attributed to avoidance or postponement of grid reinforcement costs, as well as potential cost reductions in subscription fees paid to upstream grid owners. The avoided or postponed grid reinforcement costs can be, for example, obtained from running investment models. In the short-term and continuous adjustment markets, utility is primarily related to grid operation and encompasses costs such as value of lost load (VoLL),



(a) (b)

Fig. 6. Calculation of DSO's marginal utility curve for CL product based on the impact and probability of the event at the congested hour 7336: (a) illustration of the different valuation parts of the marginal utility curve on the transformer loading plot, (b) illustration of the marginal utility ($U_w(q)$) and impact ($I(q)$) curves for hour 7336.

Table 3
The bid attributes of agents using the DSO's bid at h7336 as an example; t: time, l: location, g: sub-bid number, q: quantity, u: valuation.

ID	Date	t	l	g	q [kW]	u [$\frac{\text{SEK}}{\text{kW}}$]
d0	2021-11-01	h7336	CR	g0	71.9	0.17 (fixed)
				g1	8.3	15.17
				g2	149.8	0.00
				Sum	230.0	N/A

grid component aging and potential penalty payments to upstream grid owners. The grid reinforcement costs are highly dependent on DSOs' grid and the specific need for reinforcement, country, expected load profiles at bottlenecks, and investment lead times. In the illustration example, it is assumed that there is enough flexibility available. The continuous adjustment market requires data considering varying forecast updates, or component failures which is beyond the scope of market design and the illustrative example. Therefore, this paper solely focuses on discussing utility within the short-term market.

Since the bids structure allows multi-bidding, an algorithm is proposed to derive a curve representing valuation in relation to quantity of CL-cap product. Moreover, given the presence of uncertainties, the concept of expected marginal utility is incorporated aiming for a probabilistic approach. Algorithm 1 outlines the process of deriving the expected marginal utility curve. The general steps of the algorithm are: (1) estimating the monetary impact of congestion in a grid component, e.g., a transformer, as a function of the component's loading $I(p^{trafo})$, (2) converting the impact function to be a function of the CL-cap quantity $I(q)$, (3) obtaining a set of congestion forecast scenarios $\mathcal{W}$ and its probability set Π, (4–5) calculating a marginal utility curve U_w for each congestion forecast scenario, (6) calculating the expected marginal utility curve $E(q)$ from the marginal utility curves and probabilities of the scenarios. These steps are explained in detail below.

Algorithm 1 DSO's expected marginal utility curve for CL-cap

1: Estimate congestion monetary impact function $I(p^{trafo})$
2: Transform $I(p^{trafo})$ to $I(q)$ using Equation (4)
3: Get congestion forecast scenarios $\mathcal{W}$ and their probabilities Π
4: **for** $w \in \mathcal{W}$ **do**
5: Calculate marginal utility curve of scenario w (U_w) using Equation (5)
6: Calculate expected marginal utility curve: $E(q) = \sum_{w\in\mathcal{W}} U_w(q) \cdot \pi_w$
7: Split $E(q)$ curve into sub-bids

- **Step 1:** A potential monetary impact function I needs to be quantified that represents the cost of congestion in a component for the DSO. Here a transformer is chosen as an example. Eq. (3) given in Box I proposes a step-wise function for I where P^{trafo}_{rating} is rating or acceptable threshold for loading of the transformer; $\sum \overline{P}^{\text{net}}$ is the sum of all the sold connection capacities downstream of this component; and p^{trafo} represents different potential loading levels of the component. For loading levels above 1.2 p.u., the overload protection might be triggered and load needs to be curtailed that causes a large monetary impact, for example, close to the VoLL. For the levels between 1–1.2 p.u., the DSO might be dealing with, for example, aging in grid components (C^{aging}) and penalties charged by the upstream network owner ($C^{penalty}$). If the loading is below 1.p.u., no congestion cost is expected for the DSO.
- **Step 2:** The impact function I needs to transformed to be a function of CL quantity q using the logic behind CL-cap product as presented in Eq. (4) where P^{cap} is the imposed cap by the market. The transformation is needed for being able to derive a utility curve representing the valuation in relation to q. The equivalent transformed spans for I as a function of q is presented in Eq. (3). Fig. 6(b) shows impact function $I(q)$ for the illustration example where $\sum \overline{P}^{\text{net}}$ is 230 kW, and p^{trafo}_{rating} is 150 kW. Consequently, for q in [0, 50) kW, a VoLL of 58.1 SEK/kWh/h is taken from [42], if q is within [50, 80] a value of 15 SEK/kWh/h is assumed to represent C^{aging} and $C^{penalty}$, and for q within (80, 230] an impact of zero is assumed since the p^{trafo} loading is below p^{trafo}_{rating}. The impact function is a characteristic curve for the congested component and does not represent any specific hour or event. The impact curve is used in the remaining steps for defining the marginal utility curve for the congested hour h7336.

$$p^{trafo} \leq \sum \overline{P}^{\text{net}} - q = P^{cap} \tag{4}$$

- **Step 3:** The congestion scenarios $\mathcal{W}$ and their probabilities Π can be obtained from a probabilistic congestion forecast such as [43]. For simplicity in clarifying the algorithm, a perfect forecast is assumed in the illustration example. Therefore, there is only one scenario in $\mathcal{W}$ that has a probability of 1. The forecast shows a transformer congestion at h7336 with 158 kW of loading (Fig. 6(a)).
- **Steps 4 and 5:** The marginal utility for each scenario $U_w(q)$ at h7336 is calculated based on Eq. (5) given in Box II where the three sections of the function are illustrated in Fig. 6 with Roman numbers. If the purchased q is within section (I), the market imposed cap P^{cap} will be above P^{trafo}_w. Therefore, imposing a cap within the span of this section will not bring much utility for the DSO because it will not reduce the congestion. For this section, only 0.17 SEK per kW per hour is considered for the price

$$I = \begin{cases} \text{VoLL}, & p^{trafo} > 1.2P^{trafo}_{rating} & \longleftrightarrow & q < \sum \overline{P}^{\text{net}} - 1.2P^{trafo}_{rating} \\ C^{\text{aging}} + C^{\text{penalty}}, & P^{trafo}_{rating} \le p^{trafo} \le 1.2P^{trafo}_{rating} & \longleftrightarrow & \sum \overline{P}^{\text{net}} - 1.2P^{trafo}_{rating} \le q \le \sum \overline{p}^{\text{net}} - P^{trafo}_{rating} \\ 0, & p^{trafo} < P^{trafo}_{rating} & \longleftrightarrow & q > \sum \overline{P}^{\text{net}} - P^{trafo}_{rating} \end{cases} \tag{3}$$

Box I.

$$U_w(q) = \begin{cases} (\text{I}) : \rho^{CC}, & 0 \le q < \sum \overline{P}^{\text{net}} - P^{trafo}_{w} & \longleftrightarrow & P^{trafo}_{w} < P^{cap} \le \sum \overline{P}^{\text{net}} \\ (\text{II}) : I(q) + \rho^{CC}, & \sum \overline{p}^{\text{net}} - P^{trafo}_{w} \le q \le \sum \overline{P}^{\text{net}} - P^{trafo}_{rating} & \longleftrightarrow & P^{trafo}_{rating} \le P^{cap} \le P^{trafo}_{w} \\ (\text{III}) : 0, & \sum \overline{P}^{\text{net}} - P^{trafo}_{rating} < q \le \sum \overline{P}^{\text{net}} & \longleftrightarrow & 0 \le P^{cap} < P^{trafo}_{rating} \end{cases} \tag{5}$$

Box II.

which is the buy-back cost of connection capacity fee (ρ^{CC}) that the FSPs have already paid to the DSO for network access right. This value can be decided by the DSO depending on its own fees. This value can be predefined and fixed in the market. The fee chosen here is an example based on the average of the fees from a DSO in Sweden [44]. If the purchased q is within section (II), the marginal utility is calculated based on the monetary impact I. This is because buying such quantities would help the DSO to reduce congestion and avoid the monetary impact. ρ^{CC} is also added in this step to compensate the FSPs for limiting their access rights. If the purchased q is in section (III), the imposed cap will be lower than P^{trafo}_{rating} and thus the monetary impact is zero. $U_w(q)$ is the marginal utility curve because it shows the value of buying an additional unit of the product at each quantity.

- **Step 6:** The expected marginal utility ($E(q)$) is calculated in step 7 where π_w is the probability of each scenario. In the example, $E(q)$ and $U_w(q)$ are the same because of the perfect forecast assumption.
- **Step 7:** Finally, $E(q)$ is split into sub-bids to be sent to the market. These sub-bids are presented in Table 3 where $g0$ is corresponding to part (I) of the curve representing the unutilized capacity, i.e, baseline from DSO's perspective. The valuation for this part can be predefined and fixed. In the illustrative example, the DSO is assumed to be a non-strategic agent because DSOs revenues are usually highly regulated due to their monopolistic nature.

As a result of the product design, the marginal utility curve of the DSO would have a unique shape compared to conventional downward sloping demand curves. As discussed in Section 2.1.2, this is due to the heterogeneity of the product. By using the expected utility concept, there exist a range where the unutilized and utilized capacity is mixed because the loading and thus the unutilized capacity varies across different scenarios. This specific shape would require a special clearing algorithm that keeps the order of sub-bids. The clearing algorithm is presented in Section 2.2.4. Additionally, considerations in DSOs bidding such as rebound effects and accounting for non-flexible end-users are discussed in Section 3.7 on deployment requirements.

2.2.3. FSPs' cost of providing CL product

This subsection discusses the cost of providing CL products across the different market stages. In the long-term market, FSPs are remunerated for the availability of flexibility. Consequently, the cost of availability can be attributed to the investment costs necessary for becoming flexible. In contrast, in the short-term and adjustment markets, the cost of providing flexibility primarily relates to operation expenses. To discuss the costs in the long-term market, investment costs and the specific flexibility process are required that can vary significantly among different FSPs and their processes. Moreover, to discuss the cost in the adjustment market, analysis of failures in flexibility processes and varying forecast updates are required which is also beyond the scope of market design. Therefore, this subsection focuses exclusively on the short-term market where costs can be obtained from a deterministic energy management system (EMS).

Responding to the DSO's bid, FSPs submit their offers. In this paper, a simplistic bidding approach is assumed for FSPs that comprises of calculating the true cost and addition of a profit margin. This approach is adopted because the proposed market does not exist in real-life, and therefore historical data on the marginal unit is unavailable for estimating the last cleared price for strategic bidding in PAB schemes. Additionally, the proposed algorithm incorporates a method for calculating the cost of providing the CL product, which can also be valuable to stakeholders besides bidding algorithms that solely focus on strategic behavior.

Algorithm 2 outlines the procedure for deriving the bid curve for FSPs. The general steps are: (1) calculating normal operation cost C_0 when the FSP does not offer any CL product on the market, (2–7) calculating the true marginal cost of providing CL product as a function of CL quantity $U_{true}(q)$, and (8) adding a marginal profit to the true cost to obtain the declared cost curve $U(q)$. These steps are explained in detail below.

Algorithm 2 FSPs' bidding algorithm for CL-cap

1: Calculate C_0 by running EMS with $q = 0$
2: **for** $q_i \in (0, +2\overline{p}^{\text{net}}]$ **do**
3:     Calculate C_{q_i} by running EMS with q_i
4:     **if** model is feasible **then**
5:         Calculate $U_{true}(q_i) = \frac{C_{q_i} - C_{q_{i-1}}}{q_i - q_{i-1}} + C_{ext}$
6:     **else**
7:         $U_{true}(q_i)$ is VOLL
8:     Calculate $U(q_i) = U_{true}(q_i) \cdot (1 + \kappa) + \rho^{CC}$
9: Split U curve into sub-bids

- **Step 1:** Normal operation cost C_0 is calculated using an EMS. The EMS can be a deterministic or stochastic optimization. Normal operation refers to the scenario where agent's net-load limit is its subscribed connection capacity $\overline{P}^{\text{net}}$, or in other words, no CL-cap is considered (i.e., $q_i = 0$).
- **Steps 2 and 3:** Using a for loop, C_q is calculated representing the operation cost at various levels of q.
- **Steps 4 and 5:** For a specific q level q_i, if the optimization within the EMS is feasible, the true marginal cost $U_{true}(q_i)$ can be

calculated from C_{q_i} and $C_{q_{i-1}}$. Moreover, variable costs external to the EMS (C_{ext}) can be added separately to $U_{true}(q_i)$. This is to cover costs not included in the EMS such as asset wear-and-tear.
- **Steps 6 and 7:** If the optimization is infeasible, it indicates that the agent cannot impose the specified level of limitation except by curtailing load. Therefore, a corresponding VOLL can be considered as the true marginal cost for that particular quantity of CL.
- **Step 8:** The declared cost to the market $U(q)$ can include a profit percentage κ to make sure the agent can gain profit in a pay-as-bid scheme. Moreover, the connection capacity fee ρ^{CC} is added at the end. This fee accounts for the agent's expectation of being reimbursed for the already paid connection capacity fee, as they are limiting their right-of-use during that specific hour. This fee is equal to the buy-back cost of connection capacity mentioned in DSO's bidding.
- **Step 9:** The marginal cost curve is split into sub-bids to be declared to the market. The cumulative quantity where $U_{true}(q_i)$ is zero can be declared as $g0$ which corresponds to the unutilized connection capacity of the FSP.

The derived curve is expected to be an ascending supply curve. This is because the more the connection capacity of an FSP is restricted at a particular hour, the further deviation from FSP's normal operation dispatch will be. Therefore, the extent of deviation from the cost-optimal plan increases as the connection capacity becomes more limited.

This ascending cost curve can be divided into three consecutive sections: (1) the limitation of unutilized capacity without causing deviation from the optimal dispatch, (2) the limitation of capacity by redispatch, and (3) the limitation of capacity by load curtailment. In the light of this division, an alternative bidding strategy for FSPs can involve guessing the valuation of section (II) in the DSO's utility curve (Fig. 6(b)) and inflating the second part of their own cost curve to match that level. The presence of section (I) in the DSO's curve can act as a mechanism to prevent high prices in the first section of FSPs' curve because it would result in a mismatch of the prices and prevents those FSPs from being cleared. Potential strategies of FSPs are discussed in Section 3.4.

In the simulation example, the deterministic EMS in Appendix A.1 is used for simplicity. VoLL and connection capacity fees can be taken from the sources mentioned in the DSO's bidding. Moreover, a 0.5 SEK/kW is assumed for C_{ext}. This value is an assumption for illustration purposes and in reality depends on FSPs' system and processes. In addition, κ is assumed to be 0.5 which corresponds to a 50% profit margin added to the true cost curves. The conclusions and discussions are not dependent on this assumption because the strategic behavior is considered to be reduced by measures that contribute to increasing the liquidity and thus the competition. The details of the FSPs' bids are presented in Table A.6. The aggregation of the bids in the form of the supply curve can be seen in Fig. 7. The valuations on the supply curve are low since the EMS could have implemented a re-dispatch with a low cost.

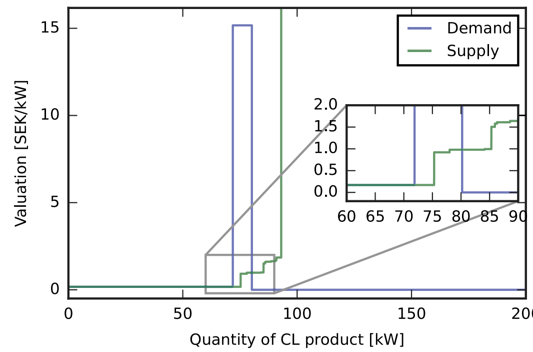


Fig. 7. Supply–demand curves for the congested hour 7336.

2.2.4. Market clearing algorithm

The clearing algorithms for the long-term and short-term markets are similar. The only difference is that in the long-term market, the valuations and quantities are for availability while in the short-term market, they represent the activation of the product.

The market clearing for these market stages is presented in (6). The objective function maximizes the social welfare at each hour t by deducting the cost of supply from the utility of the demand side. The decision variables are Ξ in which $x_{t,i,g}$ is the cleared quantity at hour t for the sub-bid g of agent i. $y_{t,i,g}$ is a binary variable representing if a sub-bid is cleared or not. y enforces keeping the order of sub-bids considering the special shape of the DSO's utility curve. $\mathcal{D}_t$ and $\mathcal{S}_t$ are the sets of demand and supply agents at hour t. As mentioned in Section 2.2.1, agents can submit their cost and utility curves as multi-bids at each hour t. $\mathcal{G}_{t,i}$ is the set of all sub-bids from agent i at hour t. $u_{t,i,g}$ is the valuation of sub-bid g that agent i has submitted at hour t.

$$\max_{\Xi} \quad \sum_{i\in\mathcal{D}_t}\sum_{g\in\mathcal{G}_{t,i}} x_{t,i,g}u_{t,i,g} - \sum_{i\in\mathcal{S}_t}\sum_{g\in\mathcal{G}_{t,i}} x_{t,i,g}u_{t,i,g} \quad \forall t \tag{6a}$$

$$\Xi = \{x_{t,i,g}, y_{t,i,g} \mid i \in \mathcal{D}_t \cup \mathcal{S}_t, g \in \mathcal{G}_{t,i}\}$$

s.t.

$$y_{t,i,g} \in \{0,1\} \quad \forall y \tag{6b}$$

$$y_{t,i,g}\sum_{g'} q_{t,i,g'} \le \sum_{g'} x_{t,i,g'} \quad \forall y, \forall g' < g \tag{6c}$$

$$0 \le x_{t,i,g} \le y_{t,i,g}q_{t,i,g} \quad \forall x \tag{6d}$$

$$\sum_{i\in\mathcal{S}_t}\sum_{g\in\mathcal{G}_{t,i}} x_{t,i,g} \ge \sum_{i\in\mathcal{D}_t}\sum_{g\in\mathcal{G}_{t,i}} x_{t,i,g} \quad \forall t \tag{6e}$$

Constraint (6b) is to limit variable y to be binary. For a sub-bid g, constraint (6c) checks whether all the sub-bids before g are fully cleared or not. If the sum of x for the previous sub-bids is less than the sum of the bid quantities in that hour, y variable of that sub-bid is enforced to become zero. This zero value would enforce the cleared quantity x for that specific g to become zero by constraint (6d). This way a sub-bid g is only cleared if all sub-bids before are fully cleared and thus keeping the sequence of the submitted sub-bids. Constraint (6e) enforces that the procured flexibility from the FSPs is larger than or equal to the amount requested by the DSOs at each timestep. The grid constraints are not included in the market clearing for simplicity at the clearing phase. This, instead, need to be incorporated in the bidding strategy of the DSO and be declared by the location and quantity of its request. The adjustment market clearing is based on a conventional bid matching in a continuous market scheme.

The market clearing algorithm internalizes an automated negotiation of the baselines (unutilized capacities). The expected baselines by FSPs and DSO are declared with $g0$ bids (the first flat part of demand and supply in Fig. 7 that are valued 0.17 SEK/kW). If the aggregated baselines of FSPs is higher than the DSO's expected baseline, i.e., a lower quantity of $g0$ on the supply curve compared to the demand curve, a negative social welfare is generated. The algorithm observes this mismatch and clears the market only if the mismatch of baselines would still lead to a net positive social welfare at a higher quantity of CL. This way, the baselines will be negotiated automatically and baseline manipulation by market participants will be limited. In addition, the purchased (sold) quantity has a clear implication in the form of a cap on the net-load. Therefore, unlike baseline-based products where the buyer and sellers may have different referencing points (baselines), the mismatch of baselines in the proposed mechanism will not lead to a different expected loading level after procurement. The clearing algorithm can also be illustrated by the total cost and utility curves (Fig. 8). The clearing algorithm maximizes the difference between

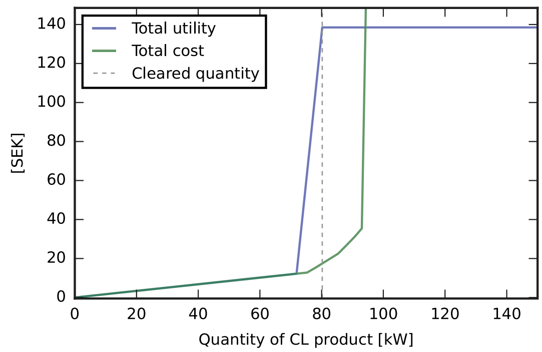


Fig. 8. Total utility and cost curves for the congested hour 7336.

total utility and cost curves. Therefore, at the cleared quantity the willingness to pay for the DSO (total utility) is always higher or equal to the total cost for the FSPs.

As a result of the internalized baseline negotiation, the strategy of market participants includes not only guessing the marginal prices but also the unutilized capacity on the supply and demand side. The dominant strategy of market participants can be identified using game theory studies as a future work. A potential setup for such an study is discussed in Section 3.4. In the illustrative example, strategic behavior is not considered as the example aims to present the notion of a CL market and product.

In the illustrative example, the market operator clears the market and informs each participant their cleared quantities (Table A.6). At the delivery hour, the flexibility providers have to activate the product according to the cleared levels in the short-term market and the traded corrections in the adjustment market. The market-imposed cap for different FSPs is shown in Fig. 9. The FSPs have to keep their net-loads below the imposed cap. The market clearing results only indicate the maximum net-load cap of the FSPs and not the set-points of their DERs at the delivery hour. The set-points are decided in a distributed manner by FSPs' EMS enabling them to optimize their portfolios and algorithms.

2.3. Market settlement and payment allocation method

There exist various payment allocations methods such as uniform-pricing (UP), PAB, VCG, and Shapley value. VCG, single-sided VCG, and Shapley payments are calculated based on the marginal contribution of each agent. These payment allocation methods have several suitable properties such as incentive compatibility for VCG and fairness for Shapley. However, VCG and Shapley require calculation of agent's marginal contributions [8]. The calculation requires assumptions about the behavior of FSPs in case they were not participating in the market. This dictates assuming a baseline for an agent when calculating their payments and can lead to the issues mentioned for the baseline. Therefore, VCG or Shapley are not considered for calculating the payments. Due to the shape of DSOs marginal utility curve, UP payments could become higher than what the DSO is willing to pay for (Fig. 10). Therefore, UP cannot be a suitable method either since it can affect the group rationality property for DSOs. On the other hand, PAB suits the described shape of the demand curve in Section 2.2.2 that represents DSOs' willingness to pay. Here, the authors do not intend to argue in favor or against UP or PAB, instead, it is the specific shape of the demand curve that indicates the payment allocation method.

Since PAB is chosen, FSPs may increase their prices to earn profit in the market. This can be seen in Fig. 10 where FSPs have increased their prices for the utilized capacity section to be slightly below the DSO's marginal utility for the utilized capacity. If FSPs offer high prices for their unutilized capacity to get paid although that capacity was not planned to be used, an elastic demand curve in combination with its proposed shape can hinder this behavior. Similarly, the elastic demand curve and its proposed shape can prevent collusive behaviors for increasing the price of the unutilized capacity. The proposed demand curve and the market clearing will either lead to the colluded FSPs not being cleared, or the total cleared quantity in the market becoming lower. Therefore, such behaviors can be detected due to the elaborated impact on the market outcomes. Regarding the utilized capacity, FSPs can guess the marginal clearing price and increase the prices for the utilized capacity to levels slightly below their guess. The proposed CL product is accompanied by various benefits including an internalized negotiation of baselines. However, the downside is that it only matches with PAB schemes due to the shape of the DSOs demand curve. Focusing on a larger geographical area and measures leading to more competition, as well as incorporating market monitoring and antitrust laws is important to hinder market power practices and thus reaching a higher market efficiency from an economic perspective. This is discussed further in Section 3.1. The potential strategies for FSPs are discussed in Section 3.4.

The formulation used for the PAB is presented in Eq. (7). The payment for each FSP at each hour is a multiplication of the cleared quantities ($x^*_{t,i,g}$) and the declared valuations for that specific sub-bid ($u_{t,i,g}$). The DSO pays the sum of calculated payments for FSPs.

$$\mathrm{PAB}_{t,i} = \sum_{g \in \mathcal{G}_{t,i}} u_{t,i,g} x^*_{t,i,g} \quad \forall i \in \mathcal{S}_t, \forall t \tag{7}$$

Regarding the market settlement, the delivery can be validated by comparing net-load measurements against the corresponding limit imposed by the cleared CL quantities. The validation requires only smart meter measurements and thus extra ICT and measurement costs are avoided. Ensuring the delivery of the service is possible through either a well-designed penalty scheme, or the enforcement of temporary physical limits through smart meters. A well-designed penalty scheme can reflect the financial losses from congestion events when FSPs willingly or unwillingly could not deliver the service. If the penalty is reflective, congestion related costs imposed on DSOs or disconnected consumers can be compensated by FSPs who have failed to deliver the service. On the other hand, imposing temporary physical limits through smart meters can provide a higher reliability for DSOs while being more restrictive. The suitable approach for ensuring the delivery can be chosen depending on regulatory aspects, the available technical functionalities of smart meters, and the preferences of market participants.

In the simulation example, the transformer active power loading is reduced to 153 kW in the corresponding hour as a result of the CL trade (Fig. 11). After delivering the service, the total net-load is slightly higher than the market-imposed cap (150 kW). This is due to losses in the grid that are not considered in the sum of the sold connection capacities (further discussed in Section 3.7). For the settlement, the measured net-load of each FSP by smart-meters is compared with the corresponding limit imposed by the cleared CL quantities. The details of PAB payments are presented in Table A.6.

3. Discussions on the market design and future work

In this section, a few aspects of the proposed design and deployment requirements are further discussed and future work is suggested. The discussions are summarized at the end into the adoption barriers and the future work.

3.1. The low liquidity challenge

Addressing the challenge of low liquidity is important for a successful market implementation. This challenge can be linked to causes within and out of the scope of mechanism design. In this work, the provided solutions are focused within the mechanism design. The incorporated design choices in the design contributes to addressing the issue

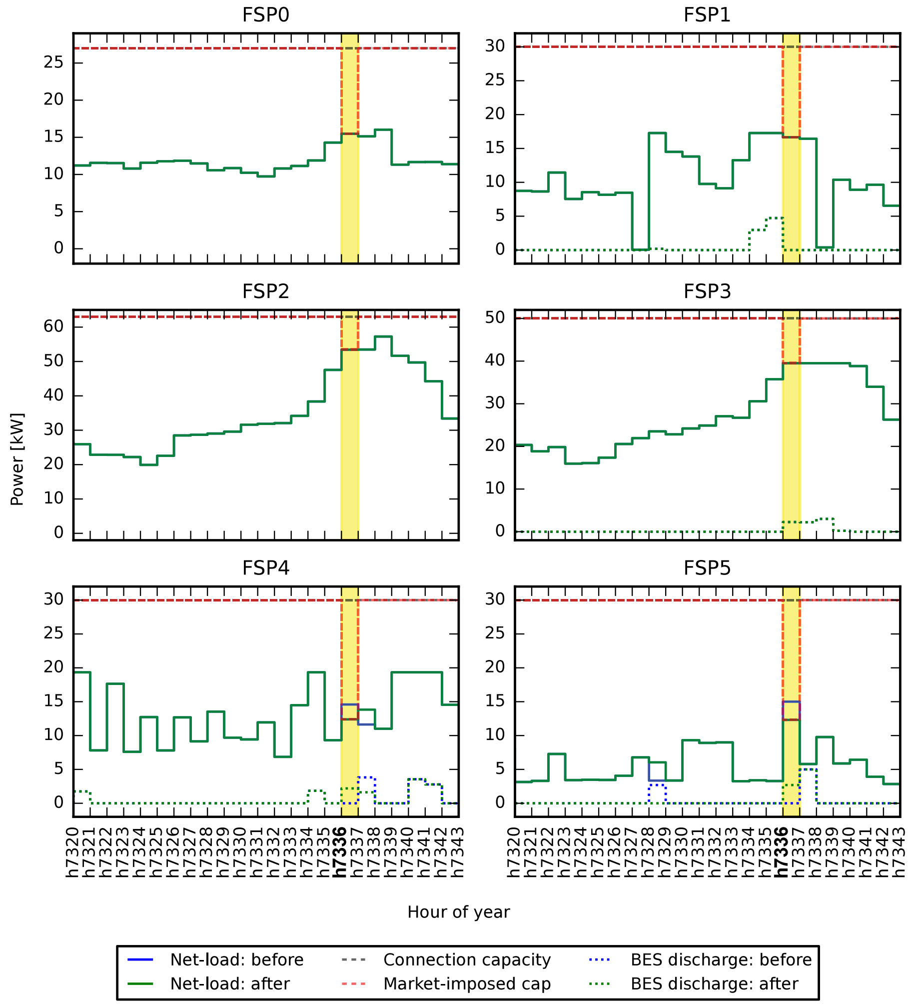


Fig. 9. The BES discharge, and net-load before and after market clearing for all the FSPs.

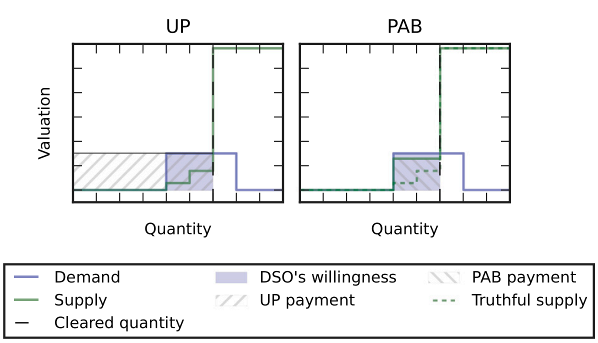


Fig. 10. DSO's willingness to pay compared to PAB and UP in the case of an abnormal demand curve.

of low liquidity and have the potential to significantly impact market outcomes. The design actively works against low liquidity by securing and incentivizing future participation on the short-term and continuous adjustment markets, as well as incentivizing investments in flexibility resources through availability payments in the long-term market. Additionally, the inclusion of features such as allowing new entry on the short-term market and enabling multi-bidding further contributes to boosting liquidity levels. Allowing new entry on the short-term market provides the opportunity for new actors, as well as actors with

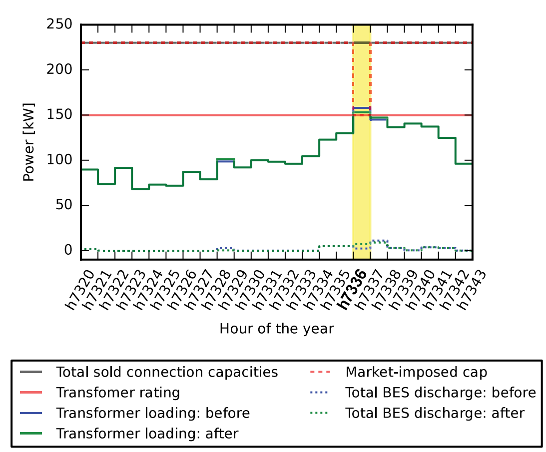


Fig. 11. Market outcomes before and after of the LFM activation.

uncertain assets on the long-term to be able to enter the market. This allows for a broader range of market participants and contributes to increasing the liquidity. Moreover, enabling multi-bidding facilitates the division of the total quantity into smaller quantity-price pairs leading to an improved bid matching for market participants. Another relevant parameter to market liquidity that is not discussed in the market design is the bid size that can be set by market regulator. A small minimum bid size is beneficial for participation of small assets [45] and thus open-up further flexible assets for the market.

The causes outside mechanism design can be geographical constraints, barriers for digitalization and automation, bureaucratic prequalification procedures, lack of relevant competences, and contradicting/unclear regulations. Solution to these causes can be studied as a future work. For example, the liquidity can be improved if the market is utilized for larger geographical areas while leaving issues at lower levels to be solved by other methods such as grid reinforcements. Evolutionary game theory can be used to analyze strategic behavior of agents as a function of the number of participants to find an approximation on the suitable geographical size for an LFM. A similar study to [46] can be done for this purpose.

An impact of having a low liquidity on the proposed design is that FSPs may exercise market power and lock the DSO in by not offering flexibility at low enough valuations in the short-term market. The mechanism can be improved by finding solutions to block such practices. A solution can be DSOs declaring an activation price-cap curve to the long-term market. This way, FSPs would know their bids in the short-term market should be less than this price-cap if they are compensated for availability within the long-term market. Moreover, allowing new participants in the short-term market besides using LFMs for larger geographical areas can increase the liquidity and the competition. Additionally, incorporating antitrust laws and market monitoring can detect, prevent and punish collusive behavior and market power practices and thus, contribute to promoting healthy market dynamics.

High transaction costs can be another scenario for FSPs not offering flexibility in the short-term market. If transaction costs exceed potential revenues, withholding capacity is a rational behavior. To improve market liquidity, it is important to reduce this cost as much as possible. In the current design, this can be reduced by, for example, the proposed automated bidding and control, and market participation through aggregators.

3.2. Linkage between long-term and short-term market stages

There exist arguments against long-term markets including: reduction of efficiency in short-term markets [19], entrance barriers for technologies with higher difficulties in long-term forecasts (e.g., demand-response) [19], and gaming in the short-term market by the FSPs that are compensated for availability through the long-term market. In our suggested framework, the long-term market is solely for availability compensations and the spot trading happens in the short-term market where new actors have the possibility to enter the short-term stage. Therefore, more competitive FSPs can enter the short-term market and provide the service instead of the availability compensated FSPs and thus prevent a reduction in the efficiency. The market entry barrier for demand-response technologies can lead to less investments in such technologies. Potential solutions can be, for example, compensation through other mechanisms such as subsidies. Thereafter, as the short-term market is open to new actors, their participation is possible for this market stage. The potential gaming in the short-term market has to be further investigated and suitable solutions to be provided as discussed in Section 3.1.

3.3. The shape of DSOs' marginal utility curve

The shape of the curve is not obeying the fundamental law of demand. A demand curve for a normal good (almost all goods), is downwards sloping but there are examples of goods with other shapes. Giffen goods are essential goods with few complements such as bread for low-income households [47], and Veblen goods are goods for which the demand increases with price, for example status symbols such as art or jewelry [48]

As discussed in Section 2.1.2, the CL product is most likely a heterogeneous good and therefore its demand curve does not necessarily need to follow the law of demand. The presented shape in Section 2.2.2 is a result of the product design. DSOs have to purchase a large amount of CL with low marginal utility (the unutilized capacity) for solving congestion. Purchasing these unutilized capacities is necessary for solving the congestion. However, CLs associated with the unutilized capacity do not have a similar impact on the FSPs' behavior in comparison with the CLs associated with the utilized capacity. Therefore, it can be said that the proposed CL product is not homogeneous.

Assuming a downward sloping demand curve is similar to assuming a baseline that is equal to the connection capacity. Although this would remove the need for a baseline, it comes with a higher cost for the DSOs. One can argue that any untruthful baseline would still be lower or equal to the connection capacity of the FSP and therefore a baseline-based LFM would be a better option than a CL-based LFM. Considering the potential costs associated with the risks of the baseline products and the ICT-related costs for delivery validation, a downward sloping demand curve can still be suitable for grids with very low excess of connection capacities. However, implementing such an LFM in residential areas with a large excess connection capacity would lead to large flexibility procurement costs for DSOs.

3.4. Market participants' strategies

In the presented illustration example and the bidding (offering) algorithms, the focus has been on elaborating the design besides calculating the true utility (cost) of the CL product. The bidding and offering strategies of the market participants can be more sophisticated, especially considering the incorporation of the automatic baseline negotiations in the market clearing. In this mechanism, market participants not only have to guess the marginal bid but also the declared unutilized capacity, i.e., baseline, by other agents. Fig. 12 shows three examples of potential FSP strategies in a hypothetical example. The sum of sold connection capacities are 15 kW, and the active power rating of the transformer is 10 kW. In case one, the expected unutilized capacity declared by the DSO is 3 kW while FSPs have declared 1 kW. The untruthfulness of the FSPs has led to market preventing the untruthful behavior by clearing only 1 kW. In this case, a lower reward is given to FSPs compared to cases 2 and 3. In case 2, the FSPs have been truthful about the unutilized capacity but have aggressively pushed up the prices for the utilized capacity to be slightly below DSO's marginal utility. In this case the market is cleared at 5 kW and the congestion is alleviated. Another strategy can be that FSPs are untruthful about their unutilized capacity but are less aggressive in increasing their prices for their utilized capacity. In case 3, the cleared quantity is also 5 kW and the FSPs would get the same reward as in case 2. These examples show how the market participants have to negotiate their baselines (unutilized capacity). The market clearing protects the market participants interest in case the mismatch of the prices and the baselines are very large and it makes sure the total utility is always more or equal to the total cost at the cleared quantity.

The dominant strategy of FSPs in this setup can be studied by evolutionary game theory in a future work. Such a study can include defining various strategies as above. An aggressive exercise of such strategies can lead to the market being cleared at lower quantities leading to a lower reward compared to less aggressive strategies. Therefore, conducting such an study would be valuable for identification of a dominant mixed strategy for FSPs.

3.5. Scalability and robustness

The scalability of the proposed design can be discussed from two angles: the required computational power for up-scaling to larger networks with larger number of FSPs, and scalability to other type of networks such as meshed distribution grids. The proposed design benefits from its distributed structure where agents compute their bidding, offering, and scheduling locally and in a distributed manner. Therefore,

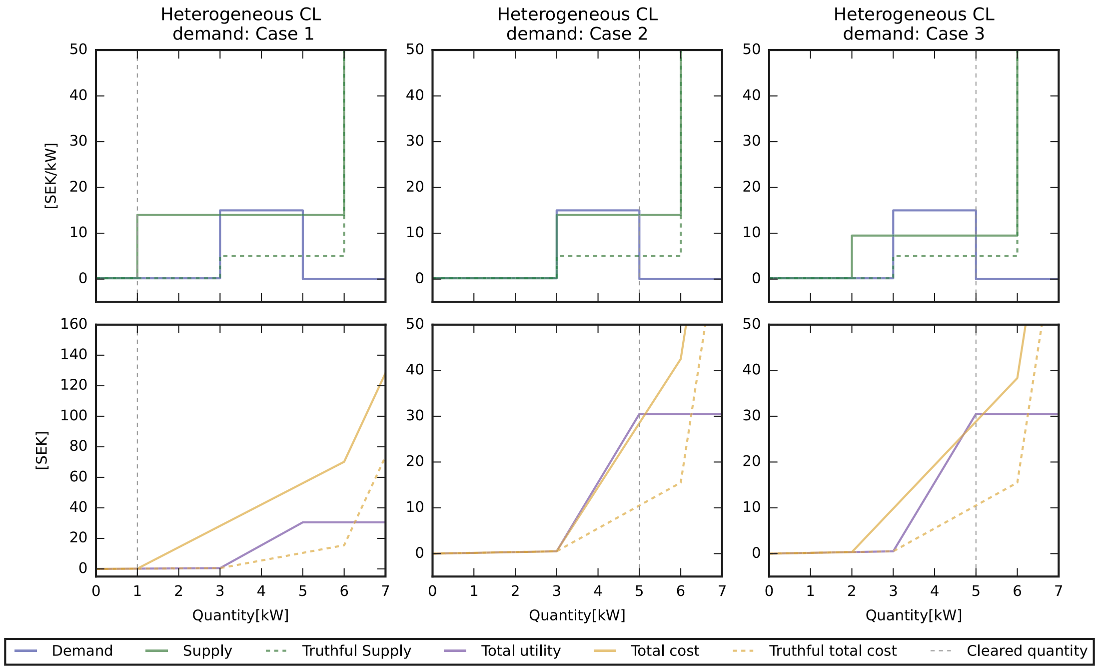


Fig. 12. Potential bidding strategies for FSPs.

Table 4
Market clearing computation time for different number of sub-bids.

# Sub-bids	30	300	3000
MILP	0.00 (s)	0.12 (s)	7.1 (s)
MILP + overhead	0.07 (s)	2.33 (s)	120.3 (s)

the required computational power for up-scaling concerns only the market clearing algorithm. The market clearing is a mixed-integer linear programming (MILP) problem where the number of variables and constraints are correlated with the received sub-bids and offers (Section 2.2.4). To compare the required computation time for clearing the market, three scenarios with 30 (the illustrative simulation example), 300, and 3000 bids and offers are compared on a laptop with Intel(R) Core(TM) i5-8365U @1.60 GHz 4 Cores, and 16 Gb of RAM using the Python interface of Gurobi 9.5.1. Table 4 shows that the computation time, even for the case with 3000 sub-bids (100 times larger than the simulation example), is acceptable for the time frame of a day-ahead market. Additionally, the overhead computation time can be further reduced by improving the code if needed. The overhead includes reading and organizing the bids and offers and transforming them into the optimization formulation.

Regarding the scalability towards meshed grids, the proposed market design is primarily tailored for addressing congestion issues in radial distribution networks. While meshed grids are relatively uncommon in distribution networks, it is still possible to adapt the design to accommodate them. One approach is to calculate the contributions of each load in the system to the power flow in a specific line using power transfer distribution factors, as described in [49]. These factors can be pre-calculated and dependent on the grid topologies. Based on these factors, the current market design can still accept bids from each load (node), which can then be re-evaluated considering their actual contributions to congestion over a line, before being cleared. Other adaptations can be running the market in sub-areas, or sending the cleared market caps/floors to the DSO to be used as a worst-case scenario for power flow calculations.

The robustness of the proposed design can be discussed from the angle of general discussions on robustness of market-based solutions. The proposed triple-stage design can provide robustness in varying network conditions by providing opportunities for availability payments, capacity-limitation service trade, and adjustments which can support the decision making of market participants. For example, through the long-term market stage, DSOs can realize in advance if there will be enough amount of flexibility available and thereof decide whether to choose flexibility or to reinforce grid. If there has been enough amount of flexibility, the DSO can procure capacity-limitation services in the short-term market. Additionally, in the case of a change in the network condition through changes in the load forecasts, the DSO can procure larger or smaller amount of flexibility depending on the updated forecasts. Even after the short-term market, further forecast deviations can be adjusted through the adjustment market. Therefore, from a market design perspective, the proposed triple-stage design can minimize the risk of congestion by providing reliability and support for decision making of the agents at different time horizons where varying network conditions can be incorporated.

3.6. Other alternatives to the proposed design

There are other alternatives to the proposed design. An alternative is a reversed one-sided auction in which the DSO purchase by the merit order until the congestion is solved. However, in one-sided auctions, the willingness of DSOs for payment is not included and thus high costs might be imposed on DSOs. Another alternative design to LFMs are local capacity markets (also known as tradable access rights). In such mechanisms, a fixed amount of available connection capacity can be auctioned or grandfathered and then the connection capacity can be directly traded between the consumers and the DSO. Similar ideas have been discussed in [50–52]. A potential challenge for this alternative is consumer discrimination regarding capacity prices at different geographical locations. An alternative to market-based solutions is tariff-based solutions. There exist different types of tariffs such as time of use (ToU) tariffs and power tariffs. ToU tariffs, if used for reflecting the local grid constraints, can lead to consumer discrimination since they can differ depending on the consumers' location. Moreover, tariffs such as static ToU and power tariffs cannot cover unexpected events or adjustments and can also lead to rebound effects by shifting congestion to other hours. The discrimination also exists for

LFMs since the opportunity for revenues from LFMs is only available to FSPs located in specific geographical areas with congestion issues. This can be especially discriminating towards end-users located at non-congested areas because DSOs pay FSPs through the collected grid tariffs from consumers located at both congested and non-congested areas. A potential measure addressing the discrimination issue can be varying the fixed part of the grid tariffs depending on the status of the grid where end-users are located. Consequently, studying a combination of solutions such as different tariff designs and market-based solutions would be valuable for finding the most social optimal solution [5].

3.7. Deployment requirements

The requirements and considerations to deploy the proposed market include: (1) smart-meters for delivery validation, (2) VoLL estimations for bidding algorithms, (3) EMS for FSPs for extracting the cost curve, congestion prognosis a few years ahead, hourly congestion forecasts up to a day-ahead, (4) consideration of end-users not participating in the market, (5) considering grid losses in the bidding of DSOs, and (6) handling rebound effects from deploying the LFM. The first 3 requirements are relatively clear. However, requirements 4–6 may need further clarification.

Regarding requirement 4, not all end-users would in real-life participate in the LFM and this needs to be considered. From the perspective of the market, these end-users can be considered as inflexible and represented by two alternatives. An alternative is to estimate their unused capacity and deduct it from part (I) of the utility curve (Fig. 6(b)). Another alternative is to submit a supply bid on their behalf in the shape of an ascending step function with low valuation in the first part (representing the unutilized capacity) and a high valuation in the second part (representing the capacity used for inflexible loads).

Regarding requirement 5, if grid losses are not considered, the loading of the congested component may end up being higher than the expected cap after flexibility procurement (as shown in Section 2.3). To address this, DSO can see grid losses as an "end-user" that consumes electricity and consider it as an inflexible end-user through the alternatives mentioned for requirement 4.

Regarding requirement 6, the rebound effects can be handled by two means: (1) the probabilistic nature of the DSO's bidding algorithm, and (2) enforcing mechanisms such as power tariffs besides the proposed LFM. The hours with a loading close to the component rating can be prone to rebound effects. The proposed probabilistic approach will lead to scenarios where congestion is expected in the neighbouring hours. Consequently, the algorithm will lead to purchasing the service for more than one step, although, the lower the probability of congestion is, the less the declared utility would be. Additionally, incorporating mechanisms such power tariffs besides the proposed LFM design, can contribute to avoiding rebounds effects by providing incentives for peak reduction. The rebound effects can be further studied in future work.

3.8. Limitations, adoption barriers and future work

Based on the above-mentioned discussions, limitations and barriers are foreseen for the adoption of the proposed design. These limitations and barriers are summarized below and future work for further studying these barriers is proposed.

1. **Market liquidity:** Although market liquidity can be improved using the mentioned suggestions, it can continue to exist and be an adoption barrier. This can raise concerns for DSOs regarding reliability of LFMs and can cause higher costs due to lack of competition. For future work, an investigation, similar to [46], on a suitable size for the LFMs can be done using evolutionary game theory and agent-based models. Moreover, non-mechanism-design related causes for low liquidity can be studied, for example, barriers for digitalization and automation, bureaucratic pre-qualification procedures, lack of relevant competences, and contradicting/unclear regulations.
2. **Potential gaming:** Another barrier is that FSPs compensated for availability through the long-term market, can exercise potential gaming in the short-term market that can raise reliability concerns. To address the potential gaming by these FSPs, finding suitable mechanisms such as price-cap curves can be investigated which can be enforced on these FSPs within the short-term market.
3. **Complexity and the DSOs utility curve:** Complexity is a limitation of the proposed design. Despite the benefits of CL products, they can increase the complexity of the design, especially considering heterogeneity of the product, and consequently the shape of the DSO's utility curve and the internalized negotiation on baselines. Therefore, the shape of the demand curve for the CL product can be further investigated in future work.
4. **Rebound effects:** Another limitation of the proposed design is that it does not inherently include direct measures against rebound effects. However, the rebound effects can be handled by the probabilistic nature of the DSO's bidding algorithm, and enforcing mechanisms such as power tariffs besides the proposed design as explained in Section 3.7. Future work can study what share of the rebound effects can be handled using these two means.

Additionally, the current study mainly evaluates the proposed design from a qualitative perspective through the identified challenges and the provided solutions. Therefore, the design can be further evaluated in a detailed quantitative study including a comparison with other congestion management methods such as power tariffs and local energy markets. The design can be quantitatively evaluated utilizing a holistic approach as proposed in [53]. The quantitative evaluation metrics can include the number of congested hours under each congestion management method, load duration curves of the critical grid components, and the cost of market participants.

4. Conclusions

In this paper, five important challenges in designing LFMs were identified and argued for from the mechanism design perspective and by literature review. A comprehensive design was proposed to address the challenges. The challenges and the proposed solutions are summarized below:

1. Low market liquidity: An integrated long-term market for flexibility availability, and allowing multi-bids,
2. Reliability concerns: An integrated triple-stage market structure,
3. Baseline challenge: A new capacity limitation product with respect to subscribed connection capacities, and a market clearing algorithm that internalizes an automatic negotiation of the unutilized capacity,
4. Forecast errors at low aggregation levels: A continuous adjustment market and probabilistic approaches for marginal utility calculations,
5. Potential high costs for ICT and delivery validation: A new capacity limitation product that its delivery can be validated using net-load measurements from smart meters.

The proposed solutions are provided focusing on real-life applications. Therefore, it can contribute to a better understanding of the problem from a multi-dimensional perspective among different stakeholders such as policy-makers, system operators, flexibility providers, and researchers.

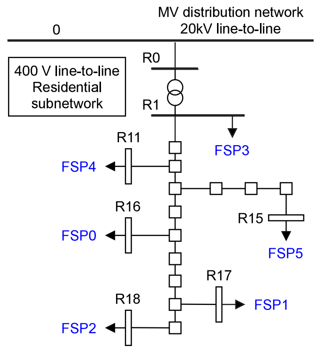


Fig. A.13. The residential sub-network of CIGRE's European Low Voltage Distribution Network [54].

CRediT authorship contribution statement

Nima Mirzaei Alavijeh: Conceptualization, Formal analysis, Investigation, Methodology, Software, Visualization, Writing – original draft, Writing – review & editing. **David Steen:** Conceptualization, Funding acquisition, Methodology, Supervision, Validation, Writing – review & editing. **Le Anh Tuan:** Conceptualization, Funding acquisition, Supervision, Writing – review & editing. **Sofia Nyström:** Validation, Writing – original draft, Writing – review & editing.

Declaration of competing interest

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

Data availability

The authors do not have permission to share data.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work the authors used ChatGPT in order to enhance readability and language. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

Appendix. Illustrative simulation example

An illustrative simulation example is designed to show how the proposed design work. The example is focused on the short-term market because: (1) the long-term market is very similar to the short-term market except that the valuations and quantities are declared with a long-run marginal cost/utility and for reservation purpose; and (2) the continuous adjustment market is a conventional continuous market. Moreover, it has been assumed that there is enough flexibility available in the example.

The residential sub-network of CIGRE's European Low Voltage Distribution Network [54] is used as the test-system (Fig. A.13). This test-system is chosen due to potentials for conducting comparable studies and benchmarking. However, in this network, neither loads are flexible, nor the transformer between buses R0 and R1 is congested. Therefore, the six loads are replaced by five flexible FSP agents, and the rating of the transformer is reduced by 70%.

The FSP agents are constructed based on real data from different sources. The gross load and PV production of the FSPs are presented in Fig. A.14. The load data for residential agents are from [55] and a local DSO in Sweden. Solar radiation data is obtained from [56]. In this case-study, battery energy storage (BES) is considered as the only flexibility resource. The energy management system of each FSP is an adapted version of our previous work [57]. The energy management system is a cost minimization algorithm that is run with a rolling time-horizon deciding the battery dispatch and PV curtailment levels. The cost function includes energy and power costs. The FSP agent module includes a bid generator function that provides the cost curve of the FSP for providing different quantities of capacity limitation product. At the moment these modules are kept simple since the aim of the example is to illustrate the market design. Details of the FSPs optimization algorithm are provided in Appendix A.1.

The DSO agent includes a congestion forecast module that runs power flow calculations based on the output of load and PV forecasts and finds the hours that CL product should be requested. A perfect forecast based on historical data is assumed for the congestion forecasts. As the case-study is designed for illustrative purposes, the assumption for the shape of the probability distribution curve would not affect our conclusions. Power flow calculations are done using the Pandapower package [58] in Python.

A.1. Optimization algorithm of flexibility service providers' EMS

In this study, flexibility service providers own battery energy storage (BES) and photovoltaic (PV) panels. The PVs have different geographical orientations. The FSPs and their assets are presented in Table A.5.

The dispatch of batteries for each FSP is decided individually by a cost minimization algorithm in their EMS that is presented in Eq. (A.1). The optimization algorithm runs every hour and decides the dispatch for the next 48 h ($\mathcal{T}$). The objective function (A.1a) includes power costs (C^{power}), energy import costs (C^{imp}), and energy export revenues (R^{exp}). The revenues from LFM is not included to extract the truthful cost curve for providing CL product. The fees for energy import (ρ_t^{imp}) and export (ρ_t^{exp}) are shown in (A.2). The fees include electricity spot-market prices (ρ_t^{spot}), power tariffs ($\rho^{\text{P}_{\text{tariff}}}$), grid energy tariffs ($\rho^{\text{gridtariff}}$), energy tax ($\rho^{\text{tax}}$), and tax returns ($\rho^{\text{taxreturn}}$) in the case of export of energy to the grid. ρ_t^{spot} is presented in Fig. A.14, $\rho^{\text{P}_{\text{tariff}}}$ is 1.21 SEK/kW for the daily peak [59], $\rho^{\text{gridtariff}}$ is 0.30 SEK/kWh [59], ρ^{tax} is 0.33 SEK/kWh [60], and $\rho^{\text{taxreturn}}$ is 0.60 SEK/kWh [61].

$$\min_{\Xi} \quad C^{\text{power}} + \sum_{t\in\mathcal{T}} C_t^{\text{imp}} - R_t^{\text{exp}} \tag{A.1a}$$

$$= \rho^{\text{P}_{\text{tariff}}} p_{\max} + \sum_{t\in\mathcal{T}} \rho_t^{\text{imp}} p_t^{\text{imp}} - \rho_t^{\text{exp}} p_t^{\text{exp}}$$

s.t.

$$\xi \geq 0 \quad \forall \xi \in \Xi \tag{A.1b}$$

$$z_t^{\text{BES}} \in \{0,1\} \quad \forall t \tag{A.1c}$$

Balance :

$$p_t^{\text{load}} + p_t^{\text{exp}} + p_t^{\text{BES,ch}} - p_t^{\text{PV}} - p_t^{\text{BES,dch}}$$

$$- p_t^{\text{imp}} = 0 \quad \forall t \tag{A.1d}$$

BES :

$$p_t^{\text{BES,ch}} \leq \overline{p}^{\text{BES}} \quad \forall t \tag{A.1e}$$

$$p_t^{\text{BES,dch}} \leq \overline{p}^{\text{BES}} \quad \forall t \tag{A.1f}$$

$$p_t^{\text{BES,ch}} \leq z_t^{\text{BES}} M \quad \forall t \tag{A.1g}$$

$$p_t^{\text{BES,dch}} \leq (1 - z_t^{\text{BES}}) M \quad \forall t \tag{A.1h}$$

$$\overline{e}^{\text{BES}} SoC_{\min} \leq e_t^{\text{BES}} \leq \overline{e}^{\text{BES}} SoC_{\max} \quad \forall t \tag{A.1i}$$

$$e_t^{\text{BES}} = e_{t-1}^{\text{BES}} + \eta p_t^{\text{BES,ch}} - \frac{1}{\eta} p_t^{\text{BES,dch}} \quad \forall t \tag{A.1j}$$

$\mathbf{p}^{\mathbf{max}}$:

$$p^{\max} \geq p_t^{\text{exp}} + p_t^{\text{imp}} \quad \forall t \tag{A.1k}$$

PV :

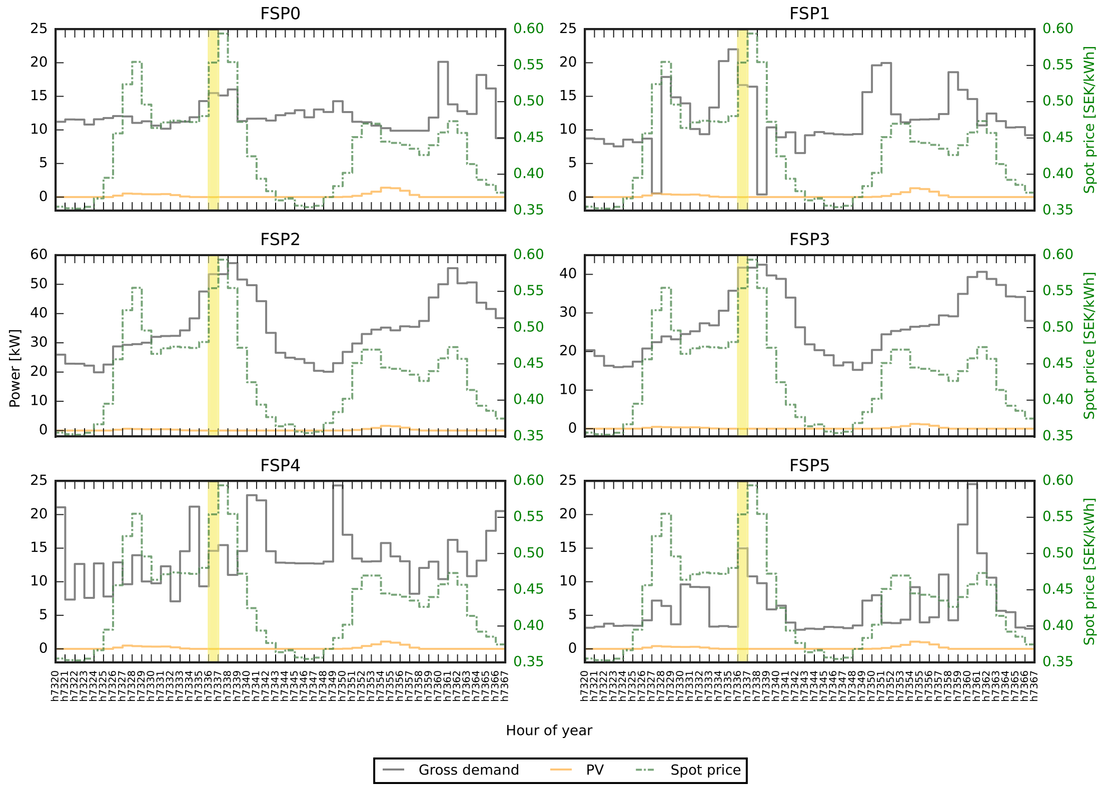


Fig. A.14. The gross load and PV production of the FSPs with the congested hour h7336 highlighted.

Table A.5
The location and the assets of FSPs.

ID	Bus	Connection capacity (kW)	PV capacity (kW)	PV orientation	BES power (kW)	BES energy (kWh)
FSP0	R16	27	15.3	West	0	0
FSP1	R17	30	12.5	South	5	13.5
FSP2	R18	63	15.3	South	0	0
FSP3	R1	50	11.8	South	5	13.5
FSP4	R11	30	12.7	East	5	13.5
FSP5	R15	30	10.3	South	5	13.5

$$p_t^{\mathrm{PV}} = r_t \overline{p}^{\mathrm{PV}} - p_t^{\mathrm{PV,curt}} \quad \forall t \tag{A.1l}$$

$\underline{\mathbf{CL-cap}}$:

$$p_t^{\mathrm{imp}} \le \overline{p}^{\mathrm{net}} - q_t^{\mathrm{CLcap}} \quad \forall t \tag{A.1m}$$

$$\rho_t^{\mathrm{imp}} = \rho_t^{\mathrm{spot}} + \rho^{\mathrm{gridtariff}} + \rho^{\mathrm{tax}} \tag{A.2a}$$

$$\rho_t^{\mathrm{exp}} = \rho_t^{\mathrm{spot}} + \rho^{\mathrm{taxreturn}} \tag{A.2b}$$

The decision variables of the algorithm are $\Xi = \{p_t^{\mathrm{imp}}, p_t^{\mathrm{exp}}, p^{\mathrm{max}}, p_t^{\mathrm{BES,ch}}, p_t^{\mathrm{BES,dch}}, z_t^{\mathrm{BES}}, e_t^{\mathrm{BES}}, p_t^{\mathrm{PV}}, p_t^{\mathrm{PV,curt}} \mid \forall t \in \mathcal{T}\}$. p_t^{imp} and p_t^{exp} are the imported and exported power at each time step. They will not occur at the same time because it would lead to higher power costs and also ρ_t^{imp} is always larger than ρ_t^{exp} that leads higher costs than revenues. p^{max} is the maximum net-load of the optimization problem. $p_t^{\mathrm{BES,ch}}$ and $p_t^{\mathrm{BES,dch}}$ are charging and discharging power of the battery. z_t^{BES} is a binary variable indicating charging mode when 1, and discharging mode when 0. e_t^{BES} is the energy content of the battery. p_t^{PV} is the final PV production after considering the potential curtailment $p_t^{\mathrm{PV,curt}}$.

The optimization is subjected to a few constraints. The balance constraint (A.1d) makes sure the input and output energy is in balance in each hour. Constraints (A.1e) and (A.1f) limit the charging and discharging power of the battery to its nominal values ($\overline{p}^{\mathrm{BES}}$). Constraints (A.1g) and (A.1h) make sure charging and discharging cannot happen at the same time using the big-M method. Constraint (A.1i) limits the energy content of the battery to a minimum and maximum state of charge (SoC) to reduce degradation in the battery. $\overline{e}^{\mathrm{BES}}$ is the nominal energy capacity of the battery in this constraint. Constraint (A.1j) is the inter-temporal constraint of the battery linking the energy content of the battery to its previous step energy content while considering charging and discharging efficiencies. Constraint (A.1k) finds out the largest net-load of the FSP in each time horizon. In constraint (A.1l), the power from the PV is calculated from the irradiation (r_t), its nominal capacity ($\overline{p}^{\mathrm{PV}}$), and the potential curtailed power ($p_t^{\mathrm{PV,curt}}$). Lastly, constraint (A.1m) limits the imported power by the sold CL-cap quantity (q_t^{CLcap}) with respect to the subscribed connection capacity ($\overline{p}^{\mathrm{net}}$).

A.2. FSPs' bids and market clearing results

The FSPs' bids at h7336, clearing results, and PAB payments are presented in Table A.6. The sum of sub-bid quantities for each FSP is equal to its subscribed connection capacity $\overline{P}^{\mathrm{net}}$. The minor deviations are due to rounding errors. The payments to the FSPs are small because the EMS of the FSPs could implement a re-dispatch of the flexible assets with a low cost. Payments to FSPs that get only their $g0$ cleared can be argue by providing a certainty for the DSO that the net-load will be under a certain cap. Moreover, this payment is a pay-back to the FSPs for limiting their subscribed connection capacity at this specific hour that is already paid for.

Table A.6
FSPs' bids, clearing results, and PAB payments at h7336 where $\overline{P}^{\mathrm{net}}$: subscribed connection capacity, g: sub-bid id, q: offered CL-cap quantity, u: offered valuation, x: cleared quantity, PAB: pay-as-bid payment.

ID	$\overline{p}^{\mathrm{net}}$ [kW]	g	q [kW]	u [$\frac{\mathrm{SEK}}{\mathrm{kW}}$]	x [kW]	PAB [SEK]
FSP0	27.0	g0	11.5	0.17	11.5	2.0
		g1	15.5	87.37	0	–
		Sum	**27.0**	**N/A**	**11.5**	**2.0**
FSP1	30.0	g0	13.3	0.17	13.3	2.3
		g1	2.6	1.61	0	–
		g2	2.0	1.64	0	–
		g3	0.4	1.70	0	–
		g4	11.7	87.37	0	–
		Sum	**30.0**	**N/A**	**13.3**	**2.3**
FSP2	63.0	g0	9.6	0.17	9.6	1.6
		g1	53.4	87.37	0	–
		Sum	**63.0**	**N/A**	**9.6**	**1.6**
FSP3	50.0	g0	10.5	0.17	10.5	1.8
		g1	0.6	1.51	0	–
		g2	2.1	1.85	0	–
		g3	36.8	87.37	0	–
		Sum	**50.0**	**N/A**	**10.5**	**1.8**
FSP4	30.0	g0	15.4	0.17	15.4	2.6
		g1	3.8	0.98	2.2	2.2
		g2	1.2	1.00	0	–
		g3	9.6	87.37	0	–
		Sum	**30.0**	**N/A**	**17.6**	**4.8**
FSP5	30.0	g0	15.0	0.17	15.0	2.6
		g1	2.7	0.92	2.7	2.5
		g2	2.3	0.98	0	0
		g3	10.0	87.37	0	–
		Sum	**30.0**	**N/A**	**17.7**	**5.1**
Total sum	**230.0**	**N/A**	**230.0**	**N/A**	**80.2**	**17.4**

References

[1] Zou Y, Zhao J, Gao X, Chen Y, Tohidi A. Experimental results of electric vehicles effects on low voltage grids. J Clean Prod 2020;255:120270. http://dx.doi.org/10.1016/j.jclepro.2020.120270.
[2] Heinrich C, Ziras C, Syrri AL, Bindner HW. EcoGrid 2.0: A large-scale field trial of a local flexibility market. Appl Energy 2020;261:114399. http://dx.doi.org/10.1016/j.apenergy.2019.114399.
[3] The European Parliament and the Council. DIRECTIVE (EU) 2019/944 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 june 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU. 2019, p. 75.
[4] Radecke J, Hefele J, Hirth L. Markets for local flexibility in distribution networks. Tech. rep., Kiel, Hamburg: ZBW – Leibniz Information Centre for Economics; 2019, URL http://hdl.handle.net/10419/204559.
[5] Jin X, Wu Q, Jia H. Local flexibility markets: Literature review on concepts, models and clearing methods. Appl Energy 2020;261:114387. http://dx.doi.org/10.1016/j.apenergy.2019.114387.
[6] EDSO, CEDEC, Eurelectric, GEODE. Guidelines of good practice for flexibility use at distribution level. 2017, https://www.edsoforsmartgrids.eu/wp-content/uploads/170524_DSOs-response-to-CEER-consultation-on-flexibility_FINAL_good.pdf.
[7] Association of European Energy Exchanges (Europex). A market-based approach to local flexibility – design principles. Tech. rep., Brussels, Belgium: Europex; 2020.
[8] Mitridati L, Kazempour J, Pinson P. Design and game-theoretic analysis of community-based market mechanisms in heat and electricity systems. Omega 2021;99:102177. http://dx.doi.org/10.1016/j.omega.2019.102177.
[9] Silva C, Wollenberg BF, Zheng CZ. Application of mechanism design to electric power markets (republished). IEEE Trans Power Syst 2001;16(4):862–9. http://dx.doi.org/10.1109/59.962438.
[10] FlexiGrid Project. FlexiGrid Project Website. 2019, https://flexigrid.org/ (Accessed 2022-02-14).
[11] Villar J, Bessa R, Matos M. Flexibility products and markets: Literature review. Electr Power Syst Res 2018;154:329–40. http://dx.doi.org/10.1016/j.epsr.2017.09.005.
[12] Etherden N, Ruwaida Y, Johansson S. CoordiNet D4.5 – Report on lessons learned, bug fixes and adjustments in products and routines within the Swedish Demo. Tech. rep., CoodiNet project; 2020.
[13] Brolin M, Pihl H. Design of a local energy market with multiple energy carriers. Int J Electr Power Energy Syst 2020;118:105739. http://dx.doi.org/10.1016/j.ijepes.2019.105739.
[14] Mirzaei Alavijeh N, Ghazvini MAF, Steen D, Carlson O, et al. Key drivers and future scenarios of local energy and flexibility markets. In: 2021 IEEE madrid powertech. IEEE; 2021, p. 1–6. http://dx.doi.org/10.1109/PowerTech46648.2021.9494828.
[15] Olivella-Rosell P, Lloret-Gallego P, Munné-Collado Í, Villafafila-Robles R, Sumper A, Ottessen SØ, Rajasekharan J, Bremdal BA. Local flexibility market design for aggregators providing multiple flexibility services at distribution network level. Energies 2018;11(4):822. http://dx.doi.org/10.3390/en11040822.
[16] Minniti S, Haque N, Nguyen P, Pemen G. Local markets for flexibility trading: Key stages and enablers. Energies 2018;11(11):3074. http://dx.doi.org/10.3390/en11113074.
[17] Woerman M. Market size and market power: Evidence from the Texas electricity market. Energy institute at Haas working papers, Berkeley, CA: Energy Institute at Haas, University of California; 2019.
[18] Pihl H, Rossi J, Edvall M. D2.1, Report on barriers for adoption of innovative market design. Tech. rep., FLEXIGRID project; 2020.
[19] Schittekatte T, Meeus L. Flexibility markets: Q&A with project pioneers. Util Policy 2020;63:101017. http://dx.doi.org/10.1016/j.jup.2020.101017.
[20] Håkansson M. Energy actors' views on demand response from heat pumps. In: 5th European conference on behaviour and energy efficiency. Zurich: ZHAW Zurich University of Applied Sciences; 2018, p. 153–4.
[21] Ziras C, Heinrich C, Bindner HW. Why baselines are not suited for local flexibility markets. Renew Sustain Energy Rev 2021;135:110357. http://dx.doi.org/10.1016/j.rser.2020.110357.
[22] Nolan S, O'Malley M. Challenges and barriers to demand response deployment and evaluation. Appl Energy 2015;152:1–10. http://dx.doi.org/10.1016/j.apenergy.2015.04.083.
[23] Pagliuca S, Lampropoulos I, Bonicolini M, Rawn B, Gibescu M, Kling WL. Capacity assessment of residential demand response mechanisms. In: 2011 46th international universities' power engineering conference (UPEC). 2011, p. 1–6.
[24] Stevens N, Merckx K, Crucifix P, Gómez I, Santos-Mugica M, Díaz Á, Sanjab A, Kessels K, Rivero E, Mou Y, Pablo Chaves Ávila J, Lind L, Olmos Camacho L, Valarezo O. Deliverable D2.1 Markets for DSO and TSO procurement of innovative grid services: specification of the architecture, operation and clearing algorithms. Tech. rep., CoordiNet project; 2021-02-20.
[25] Bouloumpasis I, Mirzaei Alavijeh N, Steen D, Le AT. Local flexibility market framework for grid support services to distribution networks. Electr Eng 2022;104(2):401–19. http://dx.doi.org/10.1007/s00202-021-01248-y.
[26] Esmat A, Usaola J, Moreno MÁ. A decentralized local flexibility market considering the uncertainty of demand. Energies 2018;11(8). http://dx.doi.org/10.3390/en11082078.
[27] Heinrich C, Ziras C, Jensen TV, Bindner HW, Kazempour J. A local flexibility market mechanism with capacity limitation services. Energy Policy 2021;156:112335. http://dx.doi.org/10.1016/j.enpol.2021.112335.
[28] Rosen C, Madlener R. An Experimental Analysis of Single vs. Multiple Bids in Auctions of Divisible Goods. SSRN Electron J 2013. http://dx.doi.org/10.2139/ssrn.2294949.
[29] Valarezo O, Gómez T, Chaves-Avila JP, Lind L, Correa M, Ulrich Ziegler DU, Escobar R. Analysis of new flexibility market models in Europe. Energies 2021;14(12):3521. http://dx.doi.org/10.3390/en14123521.
[30] Scharff R, Amelin M. Trading behaviour on the continuous intraday market Elbas. Energy Policy 2016;88:544–57. http://dx.doi.org/10.1016/j.enpol.2015.10.045.
[31] Ocker F, Jaenisch V. The way towards European electricity intraday auctions – Status quo and future developments. Energy Policy 2020;145:111731. http://dx.doi.org/10.1016/j.enpol.2020.111731.
[32] Neuhoff K, Ritter N, Salah-Abou-El-Enien A, Vassilopoulos P. Intraday markets for power: Discretizing the continuous trading. Tech. rep., Berlin: Deutsches Institut für Wirtschaftsforschung (DIW); 2016.
[33] IREMEL Project. IREMEL Project Website. 2019, https://www.omie.es/es/proyecto-iremel (Accessed 2022-02-14).
[34] InterFlex Project. InterFlex Project Website. 2017, https://interflex-h2020.com/ (Accessed 2022-02-14).
[35] INTERFACE Project. INTERFACE Project Website. 2019, http://www.interrface.eu/ (Accessed 2022-02-14).
[36] Esmat A, Usaola J, Moreno MÁ. Distribution-level flexibility market for congestion management. Energies 2018;11(5). http://dx.doi.org/10.3390/en11051056.
[37] European Commission. Development of EU ETS (2005–2020). 2021, https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/development-eu-ets-2005-2020_en (Accessed: 2022-10-27).
[38] Black J, Hashimzade N, Myles G. A dictionary of economics. USA: Oxford University Press; 2012.
[39] Dorman P. Microeconomics a fresh start. Springer; 2014.
[40] Cheng M-H, Kang H-H. Price-formation process of an emerging futures market: Call auction versus continuous auction. Emerg Mark Financ Trade 2007;43(1):74–97. http://dx.doi.org/10.2753/REE1540-496X430104.
[41] Bellenbaum J, Bucksteeg M, Kallabis T, Pape C, Weber C. Intra-day cross-zonal capacity pricing. Study Behalf Ofgem 2014.

[42] Cambridge Economic Policy Associates (CEPA) Ltd. Study on the estimation of the value of lost load of electricity supply in Europe. Tech. rep., Agency for the Cooperation of Energy Regulators; 2018.

[43] Srivastava A, Steen D, Tuan LA, Carlson O, Bouloumpasis I, Tran Q-T, Lemius L. Development of a DSO support tool for congestion forecast. IET Gener Transm Distrib 2021;15(23):3345–59. http://dx.doi.org/10.1049/gtd2.12266.

[44] EON Energidistribution. Our network fees for private customers. 2022, https://www.eon.se/content/dam/eon-se/swe-documents/swe-prislista-lag-sthlm-230101.pdf (Accessed: 2022-12-20).

[45] Alvehag K, Werther Öhling L, Östman K, Broström E, Strömbäck E, Klasman B, Lahti M, Morén G. Measures to increase demand side flexibility in the Swedish electricity system abbreviated version. Tech. rep., Eskilstuna, Sweden: Swedish Energy Markets Inspectorate; 2017, p. 78.

[46] Phelps S, Parsons S, McBurney P. An evolutionary game-theoretic comparison of two double-auction market designs. In: International workshop on agent-mediated electronic commerce. Springer; 2004, p. 101–14. http://dx.doi.org/10.1007/11575726_8.

[47] Marshall A. Principles of economics. 8th Edn 1920 ed.. Variorum Edn; 1961.

[48] Veblen T, Galbraith JK. The theory of the leisure class. Houghton Mifflin Boston; 1973.

[49] Šošić D, Škokljev I, Pokimica N. Features of power transfer distribution coefficients in power system networks. INFOTEH-JAHORINA 2014;13:86–90.

[50] Brandstätt C, Poudineh R. Rethinking the network access regime: The case for differentiated and tradeable access rights. In: Oxford energy forum, Vol. 124. The Oxford Institute for Energy Studies; 2020, p. 24–8.

[51] Bjarghov S, Farahmand H, Doorman G. Capacity subscription grid tariff efficiency and the impact of uncertainty on the subscribed level. Energy Policy 2022;165:112972.

[52] Doorman GL. Capacity subscription: solving the peak demand challenge in electricity markets. IEEE Trans Power Syst 2005;20(1):239–45.

[53] Mirzaei Alavijeh N, Song M, Tobiasson W, Steen D, Tuan LA. A toolbox for comparing congestion management solutions for distribution networks. In: 2023 IEEE Belgrade powertech. 2023.

[54] Strunz K, Abbasi E, Abbey C, Andrieu C, Annakkage U, et al. Benchmark systems for network integration of renewable and distributed energy resources. Task Force C6. 04.02, Vol. 575. CIGRE, Technical Brochure; 2014.

[55] Nyholm E, Goop J, Odenberger M, Johnsson F. Solar photovoltaic-battery systems in Swedish households – self-consumption and self-sufficiency. Appl Energy 2016;183:148–59. http://dx.doi.org/10.1016/j.apenergy.2016.08.172.

[56] Norwood Z, Nyholm E, Otanicar T, Johnsson F. A geospatial comparison of distributed solar heat and power in Europe and the US. PLoS One 2014;9(12):e112442. http://dx.doi.org/10.1371/journal.pone.0112442.

[57] Mirzaei Alavijeh N, Alemany Benayas C, Steen D, Le AT. Impact of internal energy exchange cost on integrated community energy systems. In: 2019 IEEE sustainable power and energy conference (ISPEC). 2019, p. 2138–43. http://dx.doi.org/10.1109/iSPEC48194.2019.8975145.

[58] Thurner L, Scheidler A, Schäfer F, Menke J, Dollichon J, Meier F, Meinecke S, Braun M. Pandapower — An open-source python tool for convenient modeling, analysis, and optimization of electric power systems. IEEE Trans Power Syst 2018;33(6):6510–21. http://dx.doi.org/10.1109/TPWRS.2018.2829021.

[59] Goteborg Energi. Network fees. 2022, https://www.goteborgenergi.se/privat/elnat/elnatsavgift (Accessed: 2022-11-26).

[60] Skatteverket. Energy tax on electric power. 2022, https://skatteverket.se/download/18.339cd9fe17d1714c07739ac/1639754819253/skattesatser%20el%20t.o.m.%202021-12-31.pdf (Accessed: 2017-07-01).

[61] Skatteverket. Tax reduction for microprocuktion of renewable electricity - private residences. 2022, https://skatteverket.se/privat/fastigheterochbostad/mikroproduktionavfornybarelprivatbostad.4.12815e4f14a62bc048f41a7.html (Accessed: 2022-11-26).