Local Flexibility Markets: Challenging the Economic Rationale of a Monopsony Market

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***Abstract*—Flexibility, defined as the ability of a power system to reliably and cost-effectively manage the variability of supply and demand, is a key technology for a decarbonized energy system. However, integrating flexibility services (FS) into distribution networks poses challenges related to procurement mechanisms and market structure. This paper addresses the research gap concerning the economic implications of monopsony in local flexibility markets (LFMs), where the distribution system operator (DSO) acts as the sole buyer. The objective is to propose a market mechanism that ensures efficient pricing and procurement, challenging traditional monopsony concerns. Using a counterfactual valuation approach combined with Marshallian surplus maximization in a pay-as-bid pricing scheme, we show that monopsony power can enhance welfare and ensure rational pricing; even under supply scarcity or incomplete bids, it provides economically sound procurement signals. These findings support a regulatory shift towards structured FS markets and provide a robust tool for DSOs.**

***Index Terms*-- Distribution networks, Energy economics, Flexibility services**

I. INTRODUCTION

The clean energy transition is accelerating rapidly, raising significant challenges for electricity networks, especially at the distribution level. One major question is whether grid expansion, upgrading and replacement will be able to keep the pace. The analysis of the expected change in the total final energy consumption mix gives an indication about the expected pressure in electric networks, namely in distribution grids. In 2023 the electricity consumption in buildings was 46 EJ and in transport sector was 2 EJ, raising in 2050's lowest IEA scenario, respectively to 82 EJ and to 21 EJ [1]. Assuming that most transport electricity consumption will be made in buildings areas, and that buildings areas are supported by electricity distribution networks, we can expect that DSO will have to manage a network that in 25 years will be carrying at least more than two times of today's electricity.

While in developing countries new network will appear to guarantee those loads, in developed countries the network will need to be upgraded due to ageing. In Europe around 40% of distribution networks are over 40 years old, being the adoption of a new network code on demand-side flexibility, in the course of 2025, appointed as part of the solution [2]. The draft of this network code [3] has two important sections for DSOs, pointing out where efforts must be made to answer in time to the regulation requirements.

The section about Distribution Network Development Plans (DNDP) reinforce what was already required in the Directive (EU) 2019/944 on common rules for the internal market for electricity [4], which stated that: (1) the development of a distribution system shall be based on a transparent DNDP; (2) the DNDP shall provide transparency on the medium and long-term flexibility services (FS) needed; and (3) the DNDP shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the DSO is to use as an alternative to system expansion.

With the objective of gaining an in-depth understanding of what is needed to meet these requirements, the authors published an analysis that went beyond the problematic around network planning [5]. This analysis established an end-to-end epistemological common ground for policymakers, regulators and DSOs, set the conventional planning objectives as a basis to understand the flexibility boundaries, and proposed an optimal capacity planning methodology where FS are taken as a new decision dimension, whose value can be obtained by means of a counterfactual approach, to be used in local flexibility markets [6].

This result directly addresses the current requirements in the new network code regarding the use of congestion management services in the DNDP. These services aim to alleviate or delay the need for grid reinforcement when it is cost-efficient and ensures the maintenance of electricity supply quality parameters. Furthermore, these results provide a foundation for analysis that can answer the second crucial section of the network code concerning market design for FS. This section reinforces that (1) the procurement of services for congestion management within a bidding zone shall be in accordance with transparent, non-discriminatory and market-based procedures and that (2) each systems operators shall choose, applying transparent and coordinated principles, the most effective and economically efficient option or combination of options of the different tools at its disposal, which can include grid investments, non-firm connection agreements, grid-technical measures, including non-costly remedial actions, and market-based procurement and activation of local systems operators' services or other tools to maintain active energy flows or voltage within operational limits.

Building on the findings from the earlier analysis by the authors, which concluded that the FS price should be derived using a counterfactual approach, this paper explores how this pricing has a lower limit when supply is scarce—a limit that, under certain circumstances, may need to be reassessed. This emerges from the interaction between investment deferral valuations and FS market clearing, illustrating how the DSO's monopsony power, within market-based frameworks, can enhance welfare by ensuring continued access to FS through sound economic principles.

These findings are at most importance since, despite the attention in how LFM could enhance distribution network congestion management [7] [8] [9] [10] [11] [12] [13] [14], with a significant number of research projects [15] [16] [17] [18] [19] and commercial initiatives [20] [21], a gap remains in the economic understanding of monopsony effects in LFMs. Most market design thinking assume dogmatically that single-buyer environments need independent market operator for sake of information sharing, neutrality and non-discrimination [22] [23] [24] [25] [26] [27] [28] [29], overlooking unique features of electricity distribution system that have positive implications on pricing, supplier incentives and welfare outcomes.

This paper aims to fill this gap, having as objective to develop and validate a market-clearing mechanism for FS that regulates the DSO's monopsony power to enhance efficiency, using a counterfactual valuation method aligned with regulatory and operational goals.

II. FS VALUATION

The importance of incorporating FS into distribution network planning has been emphasised in various works, as mentioned in the extensive literature review in [30]. The literature emphasises the growing recognition of the potential of flexibility, providing valuable information on how to take advantage of FS to increase planning efficiency. The advantages of flexibility have been integrated into planning in two different ways: (i) implicitly, by considering the electricity demand adjustment behaviour of consumers in reaction to external signals [31], [32], and (ii) explicitly, by considering the value of flexibility for postponing traditional grid reinforcements [33] [34] [35] [36].

The analysis done in [5] extended these ideas by proposing a counterfactual valuation framework tailored to hybrid planning, highlighting the different nature of flexibility and traditional investment, which were not considered in previous studies, having as starting point that the typical evaluation of DNDP is based on the discounted cash flow (DCF) methodology, which establishes the net present value (NPV) of the investment costs and the corresponding operating benefits [37].

The benefits in this approach are measured based on the reduction in operating costs made possible by the investment. The reduction is measured against the costs of reliability and losses in the year $t = 0$.

Changes to the optimal schedule, i.e., $t > t_0$ for the investment p_t^*, represent an opportunity to provide FS. This opportunity is viable when the economic value of this change is positive, which can happen if part of the investment costs can be postponed and the congestion that results from this postponement can be resolved using FS at lower costs than consumption or generation shedding.

In valuing FS, seeking to *maximize* the NPV consists of looking for a hybrid solution that combines investment and FS so that the corresponding NPV_F is equal to or higher than the NPV_I obtained exclusively by investing in the network.

The FS benefit can be estimated based on a demand for FS from a set of resources, $\{D_m\}$, (1).

$$BF = \gamma \sum_{m \in C} \lambda_m T_{3,m}(L_{3,m} - max\{0, L_{3,m} - D_m\}) \quad (1)$$

where $L_{3,m}$ is the load shed needed to mitigate congestion caused by the isolation of branch m; λ_m is the probability of a fault occurrence in asset m; $T_{3,m}$ is the repair time during which asset m is out of service; and γ is the unit cost of ENS.

For a well-defined demand for FS, $\{D_m\}$, and considered satisfactory by the DSO from the point of view of system security, the limit cost, CF, to satisfy that demand can be determined based on the relationship between the NPVs of alternatives, i.e., by ensuring that $NPV_F \geq NPV_I$.

In cases of insufficient FS, the problem of how to value smaller offers, $D_m < L_{3,m}$, arises. Considering that the benefit of the FS, BF, is proportional to the variation in shedding energy then a limit cost for the FS, CF, could be established as a linear function of this variation. Figure 1 illustrates this by marking with a red dot the maximum price the DSO would be willing to pay for a service 50 % lower than the required initially to match the counterfactual investment alternative.

It should be noticed that there is a service value, E_0, above which the value of postponing the investment is positive. Below E_0, the cost of doing nothing is lower than the benefit of postponing investment, given a discount rate α. Thus, for incomplete offers that do not match the complete ENS counterfactual investment solution related with structural capacity limitations, E^S, the valuation is no longer CF^* but a lower value that depends on the incomplete supply, E_i, given by (2).

$$CF_i^* = \frac{E_i - E_0}{E^S - E_0} CF^* \quad (2)$$

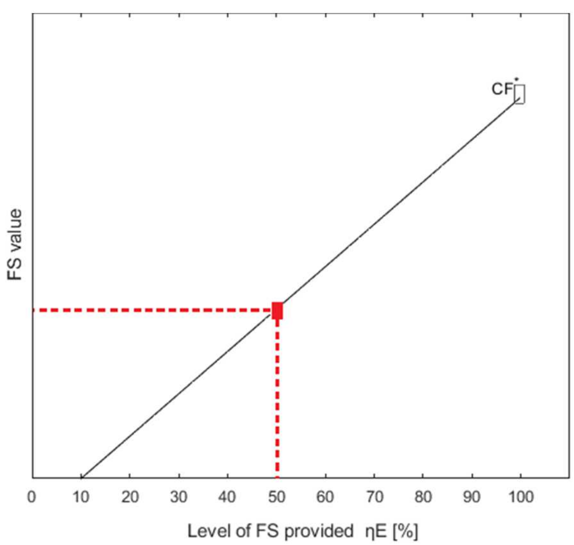

Figure 1. Counterfactual valuation of incomplete FS assuming that the benefit of flexibility is proportional to the ability to reduce congestion.

III. FS PROCUREMENT

In a FS context, the topological analysis of an electricity distribution network needs to characterize all contingency situations, $m \in C$, which are associated with asset congestion risks, s, due to the postponement of the conventional investment solution I_0. For each of these situations, i.e. for each pair (m, s), the search is aimed to identify the resources that can contribute to solve the asset congestion $\{D_k: \forall k \in N_{s-m}\}$, informing them of each and every request they have to respond to, $\{L_{3,m}\}$, the individual duration of these requests, $\{T_{3,m}\}$, as well as the likelihood of being called upon to respond to each request, $\{\lambda_m\}$.

It is the set $(\{L_{3,m}\}, \{T_{3,m}\}, \{\lambda_m\})$, that corresponds to what was previously called FS. It is for this service that we can establish, based on the counterfactual investment solution, a limit cost CF^* and, therefore, a mark-up for the P^* bid price by the DSO. For selected network development projects, the search for FS could be directed at potential service providers that have flexibility resources that can be activated in the circumstances defined by the DSO.

It is important notice that we are aiming on the demonstration about FS market equilibrium and not FS eligibility to respond to a DSO requests, being that evaluation complex namely due to the weight of localization of the FS assets [38].

Table I provides an example of a situation in which FS suppliers are asked to respond to two requests, $m = 1, 2$. For this situation of demand from the DSO, the expected value of non-distributed energy (E^S), in the absence of investment, is given by (3).

$$E^S = \sum_m \lambda_m T_m L_{3,m} = 0.04 \times 2 \times 10 + 0.20 \times 1 \times 6 = 2.0 \text{ MWh} \tag{3}$$

TABLE I. INFORMATION REQUIRED FOR BIDDING ON DEMAND FOR FS AND SUBSEQUENT VALUATION OF OFFERS.

m	λ_m	T_m (h)	$L_{3,m}$ (MW)
1	0.04	2	10
2	0.20	1	6

Table II shows a response from the FS providers to meet the demand required by the DSO in Table I. It should be noted that the offers assume that the provision of the service is provided for all the situations (m) indicated, for which each provider will indicate the maximum variation of power that it makes available to be activated if needed.

TABLE II. BIDS OF FS PROVIDERS.

i	S_i (MW)	π_i (€/MWh)
1	6	800
2	5	1200

Having characterized the demand (Table I) and the supply (Table II), the question now arises about this market equilibrium, identifying the quantities to be traded and the respective price.

Figure 2 represents CF^* and P^*, considering $P^* = \varphi CF^*$ with φ=0.5, for a range of values for the reduction in energy not supplied (E) that can be provided by the FS. The fraction φ is defined as the part of the avoided cost of the investment that will be transferred to the FS suppliers, and its complement $(1 - \varphi)$ the gain allocated to the system by contracting FS as an alternative to investment. Based on the P^* values, it is possible to evaluate the FS bidding processes as represented in Table II.

The first step is to check whether the total quantity of FS offered is sufficient for the needs set out by the DSO, i.e., whether (4) is fulfilled.

$$\sum_i S_i \geq \max_m L_{3,m} \tag{4}$$

In this example, the quantity of FS on offer is sufficient to meet the needs of the DSO, (5).

$$\sum_i S_i = 6 + 5 = 11 \text{ MW} > \max_m L_{3,m} = 10 \text{ MW} \tag{5}$$

For this reason, the maximum value to be paid for these services is obtained from the point corresponding to the complete supply of the necessary FS – the highest in the rank of the valuation line P^* shown in orange in Figure 2.

Once the maximum value is known, we then map the valuation obtained according to E and the valuation of the DSO's bid to purchase FS ($L_{3,m}, \pi_{DSO}$). The value of the purchase bid by the DSO is given by (6) (see Figure 2).

$$\pi_{DSO} = \frac{P^*}{E} = \frac{3600}{2.0} = 1800 \text{ €/MWh} \tag{6}$$

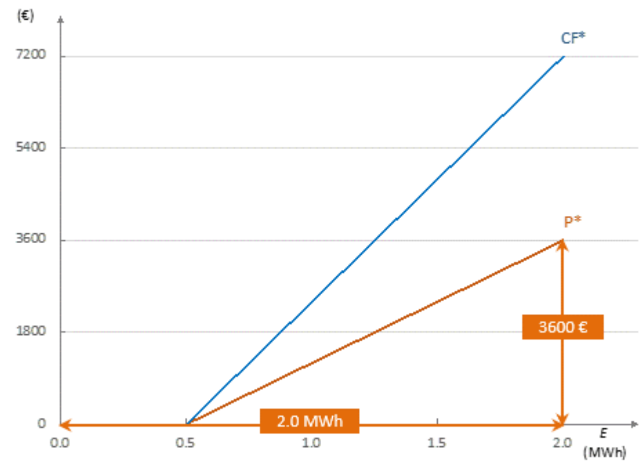

Figure 2. Counterfactual valuation of FS indicating the value of the limit cost (CF*) and the maximum value to be paid for FS (P^{*}).

This results in the DSO bidding for the purchase of FS with a price of 1800 €/MWh and a quantity equal to the maximum activation requirement of 10 MW, $m = 1$. This bid from the DSO and the sales offers (Table II) are shown in the Figure 3, for $m = 1$.

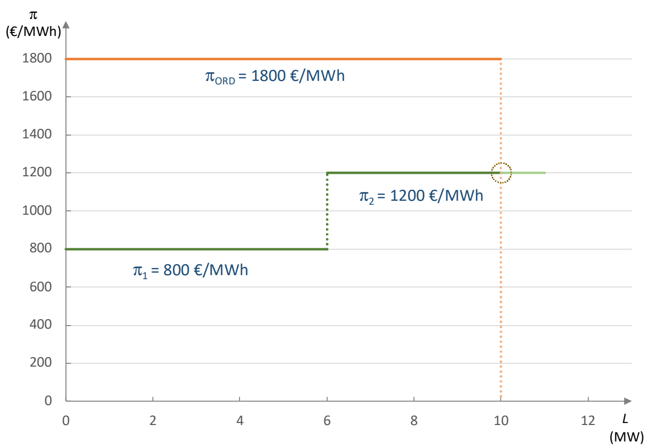

Figure 3. FS market balance with the DSO's demand and the suppliers' supply for a full supply situation for $m = 1$.

In this example, as the total quantity of FS offered is equal to or greater than the DSO's maximum requirement, and as the DSO's bid price is higher than the last sale bid needed to satisfy demand, then the market is closed for the maximum quantity (10 MW) at the market closing price, which will depend on the closing rule to be considered: *pay-as-bid (*PAB) or *pay-as-clear (*PAC) [6]. In the PAB situation, each bidder would receive the price of its bid, i.e., 800 €/MWh for the provider $i = 1$ and 1200 €/MWh for the provider $i = 2$ and in the PAC situation everyone ($i = 1, 2$) would receive the marginal price of 1200 €/MWh.

Although PAC has been adopted by most national European electricity markets [6], and some LFM analysis indicate preference for PAC, rather than PAB [39], based in the fact that the PAB is considered to be less robust against wrong beliefs and uncertainty, more exposed to asymmetries, namely due to information access, and less transparent [40], others indicate that PAC increase the cost of flexibility for the DSO [41]. Being PAB the most used closing rule in existing market platforms [25], will be the one used further to study the FS market equilibrium.

IV. FS Market Equilibrium

In the microeconomic theory the relation between the optimal consumption and production levels of a good can be obtained as the solution to a maximization problem of the total utility generated from consumption of that good less its costs of production. The optimal consumption and production levels for that good maximize this aggregate surplus measure, known as the Marshallian aggregate surplus (or, simply, the aggregate surplus) [42].

Adapting this concept to find equilibrium in a market where there are a number of potential suppliers, but the buyer is a single buyer (the DSO, in the case of the FS market), is to maximize the expected value of this Marshallian surplus (W), obtained by the difference between the DSO's valuation of the FS and the respective costs to be paid to the FS providers.

Using the PAB pricing rule, this market equilibrium can be obtained by solving the following maximization problem (U), (7).

$$\max_{\{S_{i,m}\}} \; W = \sum_{m} \lambda_m T_m \left[\pi_{DSO} D_m - \sum_{i} \pi_i \, S_{i,m} \right] \tag{7}$$

Subject to:

$W \geq 0; \pi_{DSO} = \frac{P^{*}(E)}{E}; E = \sum_m \lambda_m T_m D_m$

$D_m = \sum_i S_{i,m}; D_m \leq L_{3,m}; S_{i,m} \leq S_i$

where E is the expected value of energy not supplied avoided by contracting FS and is obtained by correspondence with the FS contracted in each request m given by $D_m = \sum_i S_{i,m}$, noticing that $S_{i,m} \leq S_i$ since the total offer of the last FS could mean a sum bigger than the DSO need.

Note that $\pi_{DSO}(E)$, as the DSO's volumetric valuation of FS, is dependent on E, which shows the relationship between the DSO's valuation of the FS and the offers made by the FS providers. This aspect is very peculiar to this problem and constitutes an additional complexity of this market, in which price offer is lower when the supply is lower, which is the opposite of most markets for other goods and services. In a market with a sole buyer, this could be seen as an abuse of the monopsony power, but this is so in this case to guarantee the interest of electricity network users in keeping the use of networks at an explainable and correct price.

This methodology applied to the example above, means that the expected value of the Marshallian surplus solving (7) would be 1872 €, which corresponds to an expected value of the FS for the DSO of 3600 € and an expected value of the FS contracting costs of 1728 €. By changing the second supplier's sales bid (i=2) from 1200 €/MWh, Table II, which is below the demand valuation of 1800 €/MWh (6), to 2500 €/MWh, which exceeds 1800 €/MWh, we have a different situation.

Although $\sum_i S_i > \max_m L_m$, the bid ($i = 2$) no longer fulfils the economic merit criterion and, as such, will not be considered in the market closure. The result is that the DSO's maximum requirement of 10 MW will no longer be met, and we are faced with a situation of incomplete supply in request $m = 1$.

As a result, the bid previously calculated for FS demand, with a value of 1800 €/MWh (6), is no longer valid in this context, as it only applies in the case of total fulfilment of flexibility needs (maximum value of 10 MW with an expected activation value of 2.0 MWh).

The new value of the maximum price can be calculated bearing in mind the partial fulfilment of the DSO's needs by 6 MW. For this situation, the expected value of the energy not supplied avoided by the DSO (E), is now given by (8).

$$E^S > E_{m=1} = \sum_m \lambda_m T_m L_{3,m} \\ = 0.04 \times 2 \times 6 \ + 0.20 \times 1 \times 6 \\ = 1.68 \text{ MWh} \tag{8}$$

Then, from (2), the valuation is no longer P^* but a value given by (9).

$$P^*(E_m) = \frac{E_m - E_0}{E^S - E_0} P^* \tag{9}$$

where E_0 is the expected value of non-distributed energy above which there is a value associated with investment postpone. Like represented in Figure 4, in this case this value is given by (10).

$$P^*(E_{m=1}) = \frac{1.68 - 0.5}{2 - 0.5} 3600 = 2832 \text{ €} \tag{10}$$

Figure 5 illustrates this new situation, with the Marshallian surplus indicated by the dotted area. This area is the graphical representation of the components that participate in the objective function of the maximization problem (U) from which market equilibrium is obtained.

Using the valuation presented in Figure 4, we now obtain a value for the DSO's purchase bid for the incomplete offer given by (11).

$$\pi_{DSO} = \frac{2832}{1.68} = 1686 \text{ €/MWh} \tag{11}$$

The expected value of the Marshallian surplus solving (7) in this situation is 1488 €, which corresponds to an expected value of the FS for the DSO of 2832 € and an expected value of the FS contracting costs of 1344 €.

It seems that, in such case where a bid doesn't fulfil the economic merit criterion, the effort to solve the maximization problem (U) is pointless, since if we solve it for the case of accepting the second supplier's sales bid (i=2) of 2500 €/MWh, it will give a value of 1456 €, value lower than 1488 €. Let's prove that is not always true, and that the mechanism for closing the FS market has to be attained by solving the maximization problem (U), not being trivial to calculate it by simply analysing offers and the DSO's valuation of the purchase of FS.

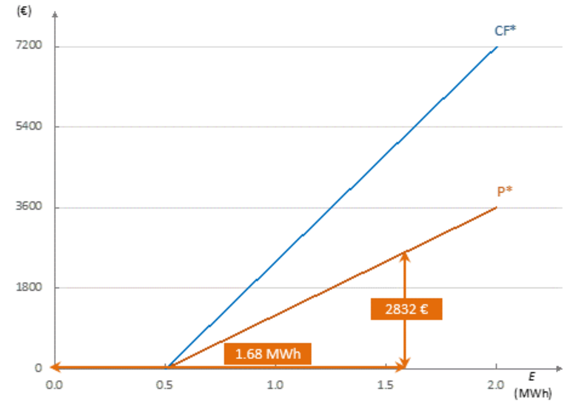

Figure 4. FS counterfactual valuation of the maximum value to be paid for FS for insufficient supply.

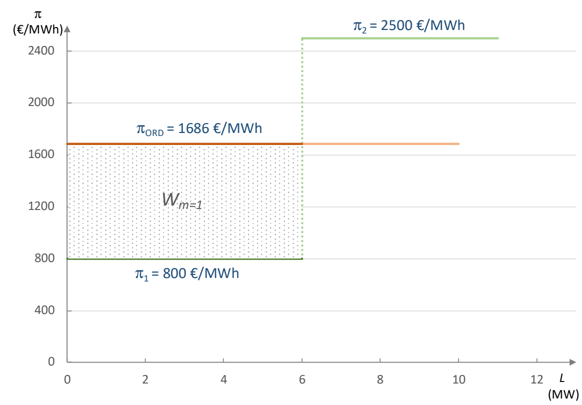

Figure 5. FS market closure with DSO demand and supplier supply for an incomplete supply situation, for $m = 1$

The following example tries to show this need for calculation given that its result is counterintuitive.

Let us consider that in the previous example we change the second supplier's sales bid ($i = 2$) from 2500 €/MWh to 2000 €/MWh. Given that this new *bid* value $i = 2$ ($\pi_2 = 2000$ €/MWh) is higher than the DSO's valuation price $\pi_{DSO} = 1800$ €/MWh, (6), for a complete supply, we would tend to consider that this bid cannot add economic value and, as such, would not be purchased by the DSO.

If it was considered that the bid ($i = 2$) does not fulfil the economic merit criterion, the outcome of the market clearing process, presented in Figure 6, where similar to the previous example and the expected Marshallian surplus would remain 1488 €.

Nevertheless, solving the maximization problem (U), considering the acceptance of an offer that doesn't fulfils the economic merit criterion, an expected value of the Marshallian surplus of 1616€ is reached (higher than 1488 €), corresponding to an expected value of FS for the DSO of 3600 € and an expected value of FS contracting costs of 1984 €, even if the bid value $i = 2$ is higher than the DSO's valuation price. Thus, in this example, part of the FS contracted is paid at a higher price than the DSO's valuation (see $W^{-}_{m=1}$ in Figure 6).

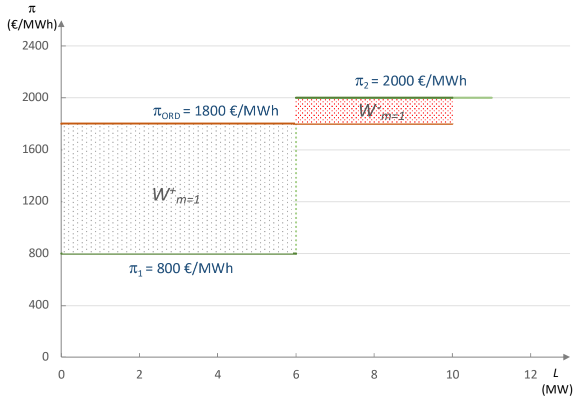

Figure 6. Closing of the FS market with the contracting of sales bids at a price higher than the DSO's maximum price for $m = 1$.

This is because, by contracting an additional FS that allows the full supply to be made available (from 6 MW to 10 MW in $m = 1$), there is an increase in the DSO's valuation (from 1686 €/MWh to 1800 €/MWh), allowing a marginal loss to be more than offset by the corresponding inframarginal gains.

It should be notice that this result is influenced by the others offers (solving the last example for bid value $i = 1$ higher than 900 € the Marshallian surplus will no longer be higher than 1488 €), and that it only applies if the considered closing rule is PAB, not be applied if we choose PAC.

V. Results and discussion

The previous example demonstrates the complexity of finding equilibrium in the FS market that arises from the fact that the valuation of demand depends on the quantity contracted.

To demonstrate this, we applied the proposed model to a compact example involving two providers responding to DSO FS requests. When supply is sufficient, the market clears at efficient prices below the DSO's valuation cap (Figure 3). When supply is above the DSO's valuation cap, the valuation dynamically adjusts downward (Figure 4), not being direct that offers above DSO cap should be rejected, since solving the maximization problem considering high-priced offers may increase total surplus, compared with a rejection based just in economic merit criterion (Figure 6).

This result contrasts with standard merit-order logic, showing that inframarginal gains can justify accepting supra-marginal prices. As stated, this only applies to PAB closing rule. Although the reasoning behind the PAC adoption by most national European electricity markets, our analysis demonstrates that the PAC approach would disable to reach a more complete use of flexibility. This reinforces the rationale behind why is the most use closing rule in existing market platforms.

Moreover, the results emphasize the importance of refining FS procurement mechanisms. They reveal that under supply limitations, dynamic pricing still supports rational decisions by DSOs and encourages participation. This is critical for addressing provider scarcity in certain geographic areas and establishing trust in market fairness.

This result and the method proposed raise awareness to the fact that, today's discrimination concerns related to the DSO's role as the single buyer in local flexibility markets, are based in the experience in markets with intrinsic differences of LFM, in the sense that, if applied the proposed method, the latter will have a price formulation contrafactual, and this way auditable, enabling to set a closing rule that is transparent and has positive implications for pricing, supplier incentives, and welfare outcomes.

VI. Conclusion

This paper focus on the economic valuation and procurement mechanisms of FS in local flexibility markets. By leveraging a counterfactual valuation methodology, we demonstrated that FS can be effectively integrated into DSOs operations while ensuring cost-efficiency and maintaining network reliability. The findings underline the importance of DSOs' monopsony power in managing FS procurement in a manner that benefits both FS providers and consumers.

The findings respond to the discrimination concerns related to the DSO's role as the single buyer in local flexibility markets, since it is showed that under the proposed approach, there is interest from all parties, DSO, FS providers and consumers to set the right price to the FS. There is no interest on hiding strategic information on market competitors from the DSO, as that would undermine the potential benefits of FS instead of create value for all parties.

The counterfactual valuation approach enables DSOs to set a rational price cap, avoiding overspending expenditure on FS while ensuring that these services remain a viable alternative to traditional network investments. Moreover, when FS supply is limited, the model's price adjustment mechanism ensures that procurement remains aligned with cost-efficiency. The study also highlighted the importance of refining FS procurement mechanisms to ensure reliability and long-term feasibility. Establishing clear bidding processes, ensuring adequate information flow between DSOs and FS providers, and setting appropriate cost benchmarks will be critical to sustaining efficient FS local markets. Addressing potential challenges, such as limited FS provider participation in certain geographic areas and the complexity of coordinating multiple service offerings, will require further refinements in procurement design and incentive structures.

From a policy perspective, regulatory frameworks must evolve to support the integration of FS as a standard tool for distribution system management. Strengthening transparency in procurement processes, refining market design to account for diverse flexibility needs, and equipping DSOs with advanced analytical tools for decision-making will be critical to maximize the effectiveness of FS markets. Encouraging broader FS provider participation will also be important to fostering competition and ensuring a robust supply of services. Future research should also explore dynamic FS activation strategies, predictive modelling for FS demand forecasting, and scalability solutions to support the broader adoption of flexibility markets in an evolving energy landscape.

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