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Economic Implications of DSO-TSO Coordination Schemes at a System Level and for Market Actors in case of Flexibility or Traditional Grid-based Solution

Carlos Madina, Amaia González-Garrido, Ines Gomez-Arriola
Energy, Climate and Urban Transition Unit
TECNALIA, Basque Research and Technology Alliance (BRTA)
Astondo Bidea, Building 700, 48160, Derio, Spain
carlos.madina@tecnalia.com; amaia.gonzalez@tecnalia.com; ines.gomez@tecnalia.com

***Abstract*— This paper proposes a methodology to evaluate the economic implication of the use of flexibility to solve both joint DSO-TSO and local DSO-specific congestion management needs. The presented methodology enables evaluating the economic implications at a system level and per market actor according to the selected DSO-TSO coordination scheme and given flexibility needs. Firstly, several DSO-TSO coordination schemes are presented to solve joint needs, in which market access to flexible resources at the distribution grid is enabled to a greater or lesser extent. Secondly, the use of flexibility is compared to traditional grid solutions (i.e., grid reinforcement, temporary commissioning services) to enable the DSO to make cost-efficient grid decisions in the short and medium term. Finally, the economic impact on flexible service providers at the distribution level is carefully presented. This methodology seeks to support energy policies and other regulatory decisions.**

***Index Terms*-- Energy Policy, Network Congestion, Power distribution networks, Power markets, Power system economics.**

I. INTRODUCTION

The Energy Transition is already raising important challenges to shift from fossil-based to zero-carbon energy sector in a cost-efficient way, in which power system operations become more complex. Closer cooperation between distribution system operators (DSOs) and transmission system operators (TSOs) will be a key issue [1]. To this end, regulation should evolve to clearly define coordination schemes (CSs) between the DSOs and TSO, standardized products, and flexibility services. To identify the most efficient way of such DSO-TSO cooperation, the CoordiNet project is investigating the economic implications of the selection of different CSs, for the procurement of flexibility and voltage services.

With the Clean Energy Package in place, DSOs now have a framework at the European level to use local flexibility and optimize network investment decisions [2, 3]. In fact, from the DSO perspective, the use of flexibility markets can offer more efficient solutions than just reinforcing the grid, applying temporary commissioning solutions, or taking other urgent remedial actions, when: a) power consumption increases due to the electrification of heating or mobility sectors, b) distributed energy resources (DERs) cause local congestion events and higher losses, c) increasing renewable energy should be accommodated in the grid, and d) the access of new electrified consumers should be allowed as far as possible. The casuistry of the problem is diverse and highly country specific.

From the flexible service providers (FSP) perspective, the participation in flexibility markets, where the needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale DERs at the distribution level [4], due to tough requirements related to the size, reliability, or communication. As presented above, DSOs can establish local markets to procure congestion management (CM) services and exploit the flexibility of small DERs. The appearance of local congestions may hinder economic development or the connection of new users to the system, as the commissioning times of grid-based solutions may be too long. Thus, the use of these local markets may be faster, most cost-efficient and a temporary solution. Local market enables to avoid congestion, while this solution may provide reduced cost of energy and improved quality of supply for the consumers and system security.

In the literature, the effects of model parameterization and formulation on congestion management results are evaluated in [5], the design of flexibility procurement markets under specific conditions is presented in [6], the redispatching for congestion relief is evaluated in [7], including optimal bids of an aggregator, and incentives are proposed for demand response in [8]. To the authors' knowledge, a holistic methodology that evaluates the economic implication of flexibility markets at a system level and per market actors is not addressed yet. In this way, this paper aims to provide a methodology to evaluate the efficiency of different TSO-DSO coordination schemes, to compare flexibility solutions versus traditional grid-based investments at a system level and in local markets (both in the short and medium term), and to evaluate the economic implication for all market agents (regulated and non-regulated).

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II. METHODOLOGY FOR THE ECONOMIC ASSESSMENT

To identify the most adequate TSO-DSO CSs and the most cost-efficient DSO grid alternative, the economic implications and overall efficiency should be investigated, especially for the use of flexibility services at both network levels and standardized products. The methodology is described in detail and applied to the demo countries investigated in CoordiNet project (Spain, Sweden, and Greece) in [9]. The methodology aims to provide a general framework that addresses: i) the assessment of the economic implication at a system level of the flexibility solution according to the selected TSO-DSO CS, ii) the comparison of the use of flexibility versus traditional grid solutions (i.e., grid reinforcement, temporary commissioning services, or others) both for solving joint TSO and DSO needs and for addressing DSO-specific local needs to enable the DSO to make the right decision in the short and medium term, and iii) the evaluation of the business model for flexible service providers and DERs at the distribution level in the provision of joint TSO and DSO and/or local CM needs.

The economic assessment of the different CSs is performed at two levels. On the one hand, the overall efficiency of the different CSs at a system level must be evaluated, while, on the other hand, the economic implications for all the involved market agents must be considered. Non-regulated agents, such as aggregators, the DERs they represent, and other FSPs, will only participate in flexibility markets if they can see an attractive business model for providing flexibility. That is, if the remuneration they receive for participating in those markets is higher than the cost of providing them, including the costs of developing and deploying the necessary information and communication technologies (ICTs). As for regulated agents, regulation must be set in a way that allows them to see a reasonable return of investment of capital, while ensuring the most cost-efficient solution from the system perspective which solves properly the given congestion management need.

Furthermore, regulated agents must ensure that they will be able to respond to any contingency in the system, so they must ensure that there will be the required availability under extreme events causing congestion. For that purpose, the proposed flexibility CM solution should be compared to business-as-usual approaches (e.g., grid reinforcements, remedial actions).

III. ECONOMIC ASSESSMENT AT A SYSTEM LEVEL

A. TSO/DSO Coordination Schemes

A coordination scheme is defined as "*the relation between TSO and DSO, defining the roles and responsibilities of each system operator, when procuring and using system services provided by the distribution grid*" [10]. Closer cooperation between TSOs and DSOs is essential for enabling TSOs and DSOs to fulfill their duties in a manner that minimizes societal cost at a system level. Market-based procurement of some system services (voltage control, inertial response, black start, controlled islanding) is currently under discussion. In contrast, there are already well-established markets for balancing services [11] and the European regulation poses on the TSO the responsibility of ensuring system balance. Hence, one of the most promising approaches for flexibility is the market-based procurement [3]. In this line, the economic evaluation of the CM through market-based procurement has drawn attention within the Coordinet project [12]. Thus, the economic assessment in this paper evaluates the economic implications at a system level of applying different CSs [13] to procure CM services at the transmission and distribution levels:

- *Common Market Model (CMM)*: both local and joint needs coming from DSO and TSO are considered in a single market. Thus, the TSO can use assets connected to the distribution grid to solve all system needs.
- *Multi-level Market Model (MMM)*: it is a variation of the CMM, in which each system operator uses its own market, rather than through a single market. Two alternatives can be considered in this case:
  - The unused bids in the market operated at the distribution level are forwarded automatically to market operating at the transmission level.
  - Aggregators and other FSPs are allowed to send new bids for their unused flexibility afterward to the market operating at the transmission level.
- *Fragmented Market Model (FMM)*: the market is split as in the *MMM*, but the TSO has no access to DERs. Hence, resources connected to the distribution grid can offer only their flexibility to solve the DSO needs.

B. Comparison of the coordination schemes at a system level

This subsection III-B presents the economic efficiency of the different CSs at a system level, which can be measured by comparing the costs for regulated agents (i.e., TSOs, DSOs, and market operator (MO), which is taken as a regulated agent in this analysis). The MO platforms may be located on the TSO and/or DSO premises, or the MO role may be an independent agent [14]. To present the most generic case, the roles of the Transmission Market Operator (TMO), Distribution Market Operator (DMO), or Common Market Operator (CMO) are evaluated independently from the role of the TSO and DSO.

As shown in Figure 1, the economic impact at a system level of the flexibility solution per each CS should be evaluated, including the procurement of the services as well as other regulated costs. The capital (CAPEX) and operational (OPEX) terms related to the software platforms (SW) and ICT costs for all actors are included, as well as the cost for the procurement of the CM at the distribution and transmission levels.

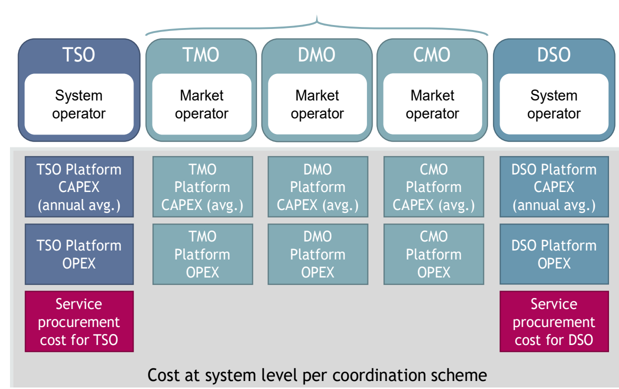

Figure 1. Economic impact of flexibility solution per CS at a system level.

For consistency in the evaluation of the deployment of the flexibility CM solution, the comparison of CSs addresses only CM cost, leaving aside the potential impact in the participation in balancing markets, wholesale markets or other grid services.

The annual average CAPEX ($\overline{Capex}^{flex}_{n,CS}$) is used as a metric to evaluate investments 'i' along its lifetime '$\mathcal{N}^i$' (i.e., 10 years for software and ICT investments), as in eq. (1). It allows for a fair cost comparison between other grid investments with low/high capital and high/cost operating costs (and vice versa) and different project lifetimes. The regulated actors recovered their investments through annuities, in line with [15], in which the annual CAPEX per CS in eq. (2) ($Capex^{flex}_{n,CS}$) includes amortization and financial terms per each year 'n' along its lifetime '$\mathcal{N}^i$'. The amortization term is the annual tangible asset costs ($TCost^i_n$) divided by the asset lifetime '$\mathcal{N}^i$' of the investment 'i', while the financial remuneration term represents the annual interest accruing, based on the financial remuneration rate '$\mathcal{R}^i$' and the annual tangible asset costs.

$$\overline{Capex}^{flex}_{n,CS} = \frac{\sum_{n=1}^{\mathcal{N}^i} Capex^{flex}_{n,CS}}{\mathcal{N}^i} \qquad \forall n \in \mathcal{N}^i \qquad (1)$$

$$Capex^{flex}_{n,CS} = \frac{TCost^i_n}{\mathcal{N}^i} + TCost^i_n \cdot \mathcal{R}^i \qquad \forall n \in \mathcal{N}^i \qquad (2)$$

On the other hand, the annual operating expenses in the year 'n' gathers the OPEX component for the operation and maintenance (O&M) cost related to the market platform.

IV. Economic Impact on Regulated Market Actors

This section IV addresses the comparison between the use of flexibility and other traditional grid solutions (i.e., grid reinforcement, temporary commissioning services, or any remedial action) for both joint and local needs, especially to enable the DSO to make the right grid decision from the power system perspective. As exposed in [3], "*reinforcement should always be compared with getting flexibility from the resources in the system and the optimal solution should be determined*".

A. Joint DSO-TSO congestion management

The casuistry of the congestion and grid alternatives is diverse and highly country-specific, so the flexibility solution will be compared versus some potential grid-based alternatives. According to the demo countries investigated in CoordiNet project (Spain, Sweden, and Greece), a general framework to establish the comparison between flexibility solution and traditional grid solutions is presented in Figure 2. The accumulated costs for both alternatives are evaluated along a variable flexibility commissioning time, with the aim of comparing the economic impact on regulated market agents for diverse grid planning solutions and supporting the decision-making process of the medium-term grid expansion plans.

In order to compare both grid alternatives with different lifetimes, the accumulated cost for both alternatives should be evaluated for a specific time span. In this case, the flexibility commissioning time ($\mathcal{T}$) is used as a dynamic time span, with the aim of supporting the decision-making process of the medium-term grid expansion plans (i.e., the upcoming 5 years).

Once the consideration of the flexibility markets as a potential means to solve system needs is granted (it has already been borne at system level), the cost of their implementation (i.e., CAPEX for the ICT and SW platforms to enable new flexibility markets) becomes a sunk cost. Hence, it must not be considered when evaluating whether flexibility or grid reinforcement is the best solution for a given system need [3].

From the flexibility solution side, OPEX terms related to the SW platform and ICT costs for all actors are included, as well as the cost for the CM service procurement, both at the distribution and transmission levels. In the case of Sweden, the cost of the temporary subscription should be also added when flexibility is not enough to solve all the congestion issues. The regional DSOs have a contract with a specific subscription level towards the TSO, which might be extended i.e., in peak time.

From the Business as Usual (BaU) grid alternative, both CAPEX and OPEX terms for new grid assets (where necessary) are included, as well as the cost for the CM service procurement at the transmission level (if exists), considering the scenario of the avoidance of CM at distribution level.

In the case of Sweden, the BaU grid-based alternative to the use of flexibility is not reinforcing the grid, but to make use of temporary increases of subscription level (access capacity to higher level network, i.e., the regional distribution network or the transmission one). This temporary subscription is an extra cost to DSOs, in addition to the annual capacity subscriptions that allow the power consumption up to the agreed capacity with the TSO or the regional DSO. Even worse, higher penalty costs for surpassing the agreed subscription may happen in case of the subscription level was denied (see e.g., [16]).

The flexibility solution will be the preferred option for the DSO if the economic impact of using flexibility (OPEX, service use, and subscription) is lower than the economic impact of the grid alternative, as presented in Figure 3.

It can be pointed out that the CAPEX, OPEX, and service procurement costs are recovered by the DSO via network tariffs (including a reasonable rate of return of investment), while the DSO subscription costs are not recovered, so that the DSO has a direct economic incentive to reduce them as much as possible.

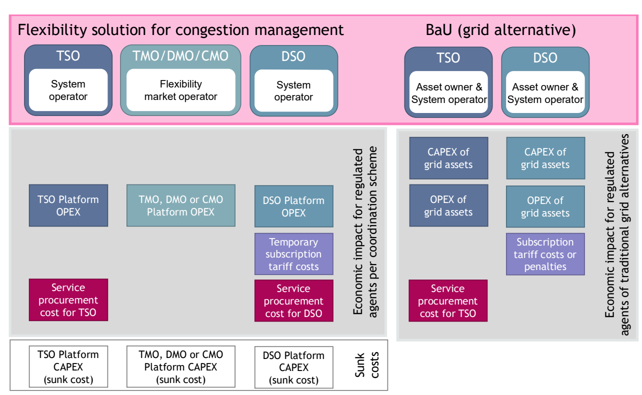

Figure 2. Comparison flexibility use cost versus BaU alternative cost.

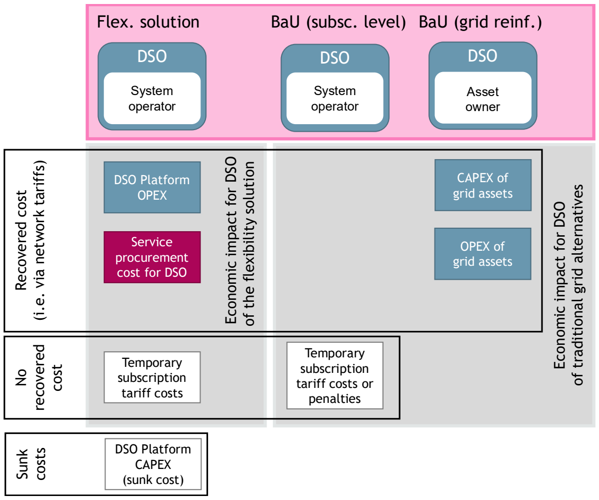

Figure 3. Comparison of the DSO economic implications for the flexibility use versus BaU alternatives (reinforcement or subscription tariffs).

B. *Local DSO congestion management*

Participation in flexibility markets (under CMM, MMM, and FMM), where the needs of both TSOs and DSOs are satisfied, is not an easy task for small-scale DERs or energy aggregators with limited resources. Technical and economic requirements are tailored to ensure the overall power system security and were designed to be suitable for large-scale players, but not for small DERs at the distribution level.

DSOs can procure congestion management services, according to transparent, non-discriminatory and market-based procedures, as long as "*such services cost effectively alleviate the need to upgrade or replace electricity capacity and support the efficient and secure operation of the distribution system*" (Art. 32, EU 2019/944) [2]. Hence, DSOs can use local markets to avoid grid reinforcements when those markets are transparent, non-discriminatory, and provide a cost-effective solution. Thus, the *local market model* (LMM), where the DSO buys flexibility to solve a local need in one market and no interaction with the central flexibility can be used [13].

This subsection IV-B describes the conditions under which the use of flexibility can postpone or temporarily replace traditional grid solutions to solve DSO-specific needs. The general framework to establish the comparison between the two alternatives to solve local congestions is presented in Figure 4.

Additionally, the comparison of the economic impact that the flexibility and BaU grid-based solutions have on the DSO is carried out at two timeframes: a remedial action for the short-term and a grid reinforcement for the medium-term.

In the short term, when there is a need for an urgent solution to avoid local CM, in which non-supplied energy must be a DSO concern, the flexibility solution may be compared to the cost of a remedial action. While, in the medium term, the use of flexibility for a longer commissioning time (i.e., 5 years) may be compared to the cost of a traditional grid reinforcement when the DSO should make decisions for the network planning.

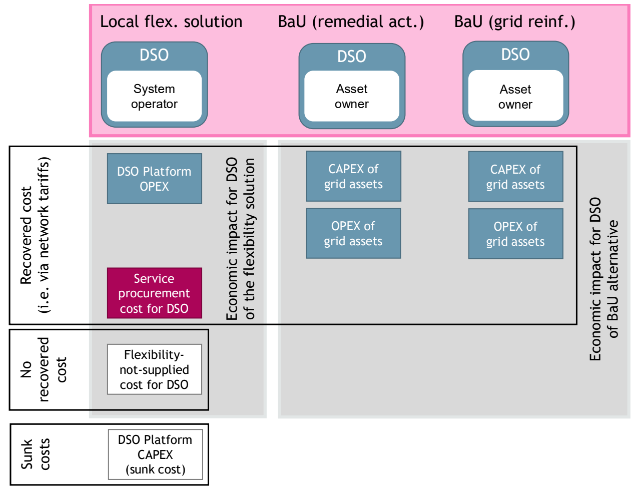

Figure 4. Comparison of the DSO economic implications for the local flexibility use versus BaU alternatives (reinforcement or remedial action).

From the flexibility solution side, CAPEX is considered to be sunk costs for the DSO, as stated in the subsection IV-A, while OPEX terms related to the SW platform and ICT costs and the cost for the CM service procurement at the distribution level are considered. Additionally, there may be some "flexibility not supplied" (FNS) when there is not enough available flexibility, and no traditional grid solution is implemented. This FNS could result in non-supplied energy to consumers (and high DSO cost) if no action is taken.

In contrast, the DSO, in the BaU solution, should consider CAPEX and OPEX of the traditional grid reinforcement (i.e., repowered line, new transformer, new generation asset, etc.) as both grid alternatives have different lifetimes. In order to evaluate which is the best solution along the same life span, the flexibility commissioning time ($\mathcal{T}$) is used as a dynamic time span (i.e., 1-5 years) in which the accumulated costs are calculated and compared among both grid solutions.

In the medium-term, the economic impact on the DSO is evaluated for a variable time span, which could correspond to a given flexibility commissioning time (i.e., 5 years). Whereas, in the short-term, the economic impact on the DSO is evaluated for a specific time span ($\mathcal{T}$=1), as the urgent and temporal remedial action is addressed on an annual basis.

In case of occasional congestions (low energy flexibility) flexibility use may be a faster and cost-efficient solution than reinforcing the grid or taking costly remedial actions, via short-term market procurements. In case of structural congestions, the quality and security of supply is at higher risk, so bilateral contracts to ensure sufficient availability of flexibility would be recommended. Under some circumstances, the flexibility solution will be a faster and temporary solution to avoid or postpone grid reinforcements, or temporarily replace, while they are commissioned and come into service.

V. BUSINESS MODEL FOR NON-REGULATED AGENTS

This section V addresses the business model for non-regulated market agents, in which the profitability of the provision of flexibility services by FSPs and DERs is evaluated under the three TSO/DSO CSs or in local markets.

A. Joint DSO-TSO congestion management

Non-regulated agents, such as aggregators and other FSPs, will only participate in flexibility markets if they can see an attractive business model for providing services. That is, if the remuneration that they receive for participating in those markets is higher than the cost of providing them. In this paper, the flexibility providers are classified according to the network to which their resources are connected:

- *FSPs at the transmission network* (FSP@T) are mostly direct owners of flexible resources participating in the provision of the grid services of joint DSO-TSO CM.
- *FSPs at the distribution network* may be direct owners of flexible resources participating in the provision of the grid services of CM (FSP@D) or may be aggregators (FSP-ag@D), either independent or not, which encompass the multiple types of flexible DERs and end-users connected to the distribution grid.

All FSPs receive market incomes by the provision of flexibility services (from the TSO, from the DSO or from both in the case of the CMM), but they must deal with additional costs associated to its business activity, as depicted in Figure 5.

Regarding costs, there will be several components:

- Costs for developing, deploying, and operating the SW platforms and ICT infrastructure to participate in flexibility markets, including both CAPEX and OPEX. Pure hardware equipment (HW) should be included. In the case of aggregators, it is assumed that they pay for the costs of local controllers installed at the premises of DERs and of the ICTs to control them. Some other costs, such as extra personnel costs, may also be added.
- It is assumed that MO(s) charges a fee for participating in flexibility markets to aggregators and other FSPs, which is used to pay for i.e., O&M of the platform.
- When flexibility is provided by demand side or storage units, flexibility actions are expected to create some rebound effect, in which the aggregator and other FSPs should redispatch the load profile or take energy time-shift actions, which will imply some extra costs.
- Depending on the regulatory scheme, aggregators and other FSPs may be required to compensate the relevant Balancing Responsible Parties (BRPs) for the imbalances resulting from the activation of flexibility, when they imply an imbalance charge for the BRP.
- In the case of the independent aggregators, they will remunerate DERs based on the flexible energy provided, according to a bilateral contract (i.e., price-indexed, flat rate, etc.). If the aggregator is also the retailer, a bill discount or auxiliary services may be offered, but it would still be a cost for the aggregator.

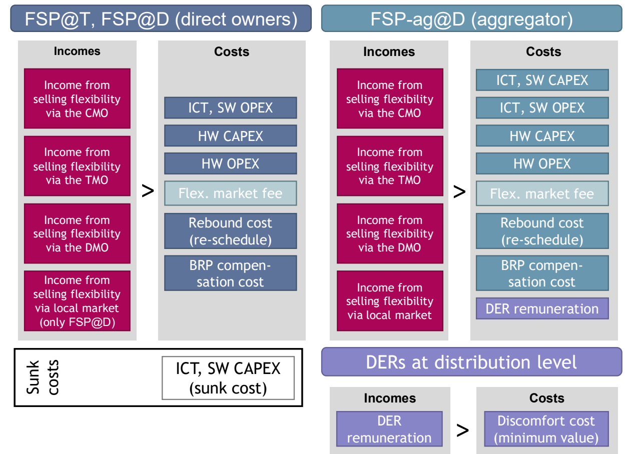

Figure 5. Business model for non-regulated actors.

Focusing on market incomes, aggregators and other FSPs will receive a remuneration for participating in the different flexibility markets (via the CMO, TMO, or DMO) The market incomes obtained from the FSPs will vary depending on the market clearing process (pay-as-bid, pay-as-clear, etc.), the adopted DSO-TSO CS, and the features of other competitors (demand response, generation units, etc.).

B. Local DSO congestion management

The business model seems to be still uncertain and risky under the simulated cases, especially when the solution is only implemented in one specific location. The high entry costs (SW platforms, communication infrastructure, prequalification, market participation fee, etc.) and demanding technical and communication requirements discourage the participation.

As presented in section I, DSOs could establish local market models (via a local market operator) to exploit the flexibility of small DERs to solve congestion issues at the distribution level. These local markets may be more accessible and attractive for small DERs, as communications and reliability requirements (and, thus, costs) may be lower, while they can also provide a highly valuable service for the DSO at the local level.

VI. CONCLUSION

This paper presents a general methodology to evaluate the economic implications of the use of flexibility markets to solve CM needs, with the focus on comparing the procurement of flexibility versus traditional grid solutions (grid reinforcement, temporary commissioning services, or any other remedial actions), and taking into mind the diversity of commissioning times, lifetimes, and cost allocation of each solution. To procure flexibility solutions, DSOs should develop and deploy SW and ICT-based platforms, which require massive investments, but they are easily scalable and replicable, enabling them to solve issues in many different locations, and making the flexibility solution a potential cost-efficient alternative as its deployment increases. This methodology seeks to support energy policies and other decisions from the regulatory perspective (i.e., incentives to foster the investments in innovative solutions from the TSO and DSO side and enable a cost-effective framework for flexible resources in the provision of flexibility services).

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