IEEE Access
Multidisciplinary ⋮ Rapid Review ⋮ Open Access Journal

Received 23 September 2023, accepted 30 September 2023, date of publication 5 October 2023, date of current version 19 October 2023.

Digital Object Identifier 10.1109/ACCESS.2023.3322365

APPLIED RESEARCH

Value of Flexibility Alternatives for Real Distribution Networks in the Context of the Energy Transition

FERNANDO-DAVID MARTÍN-UTRILLA[1,2], JOSÉ PABLO CHAVES-ÁVILA[3], AND RAFAEL COSSENT[3]

[1]i-DE Redes Eléctricas Inteligentes, 46130 Valencia, Spain
[2]Comillas Pontifical University, 28015 Madrid, Spain
[3]Institute for Research in Technology (IIT), Comillas Pontifical University, 28015 Madrid, Spain

Corresponding author: Fernando-David Martín-Utrilla (fmartin@iberdrola.es)

ABSTRACT The distribution grid faces several challenges related to the decarbonisation of the economy, which require incorporating flexibility services alongside traditional grid reinforcement solutions to enable an efficient grid development. Flexibility services, as well as the needs that require them, are very diverse. Therefore, general estimations about the value of flexibility applicable to any given scenario are unfeasible or imprecise. This paper reviews the literature on the quantification of the value of flexibility and proposes a broad-spectrum methodology aligned with the actual challenges of the energy transition for the planning of distribution network as it includes a comprehensive analysis of the real costs and the type of needs. Based on it, four representative and realistic case studies compare the BAU (business as usual) solutions with flexibility services analysing the technical and economic perspectives. Results show that flexibility value depends on the case studies considered and that, under certain circumstances, BAU solutions can be more competitive than alternatives with flexibility services. Network reinforcements in the distribution network have a long lifespan and provide a reliable service to thousands of customers. However, flexibility services can be particularly useful for accelerating decarbonisation with flexible connections or short-term solutions to manage the distribution network operation.

INDEX TERMS Congestion management, flexibility evaluation, flexible connection, power distribution planning, systems operation.

I. INTRODUCTION

The energy transition brings a new paradigm in which dimensioning new grid components should not follow the same conventional approach anymore, i.e. infrastructure is no longer dimensioned solely for peak demand. Distribution System Operators (DSOs) will also need to study the effects of distributed generation (DG), new loads and storage and their reliability, which means dealing with more uncertainty. The unquestionable necessity in the investment of new infrastructures requires a prior review process in which network users with diverse profiles, including consumers, generators, storage units or a mix of them can have incentives to adjust to the grid conditions, becoming an alternative to traditional network reinforcements. Peak demand with low local generation or peak local generation with low demand are scenarios that can be actively managed by the DSO.

Digitalisation technologies enable active management of networks and data exchanges between DSOs and their grid users, or among system operators. However, the vision of an uninterruptible electricity supply as an essential service is still in force. The strategy of managing the power profile from network users, both demand and generation, according to the network conditions needs to be carefully reviewed. Some electricity usages are not flexible enough, and the flexibility services will not meet their goals if the incentives are insufficient to move away from the BAU (business as usual) solution.

The associate editor coordinating the review of this manuscript and approving it for publication was Qiang Li.

The use of flexibility in distribution networks has been addressed extensively in the literature as shown in [1], [2], and [3]. Flexibility has also been tested in different pilots from different purposes with convincing results. Projects such as CoordiNet [4], EUniversal [5] or OneNet [6] demonstrate that services based on the active management of grid-connected resources can provide efficient and beneficial services and products for the operation of the distribution network and enable efficient use of the distribution network focusing on TSO-DSO coordination, platform development, service design or market testing.

In this paper, a literature review is conducted on assessing flexibility in comparison to traditional solutions from different points of view: methodology, costs considered, and the drivers taken into account. A practical methodology to evaluate the value of flexibility is proposed, including a complete cost calculation aligned with the real needs in managing distribution networks. This paper also selects a set of representative case studies by making a prior analysis of the drivers that determine the present and future network planning and draws some conclusions on the real usefulness of implementing flexibility services in different cases. Conventional solutions and flexibility alternatives are analysed, and an economic study of the possible solutions is carried out. Finally, considering the risks of dealing with more unpredictable parameters even close to real-time in a more dynamic way of operating the grid, a sensitivity analysis is necessary to calculate a range of cost-effective conditions for using flexibility.

This paper continues as follows. Section II presents the literature review to guide the methodological approach. Section III describes the methodology used to evaluate flexibility solutions. Section IV describes four case studies where flexibility solutions can be alternatives to BAU network investment, compares the results of the case studies and discusses the relevant parameters where flexibility can be alternative for BAU investments. Finally, Section V draws the main conclusions.

II. LITERATURE REVIEW ON FLEXIBILITY EVALUATION

As a preliminary step, a literature review on three related topics has been carried. Firstly, the type of methodologies applied in the literature are analysed. Secondly, this section studies what inputs have been considered to assess the value of flexibility; and, thirdly, an analysis of what use cases have been evaluated is made. Given that the objective is to obtain an accurate estimation of the value of flexibility, all three aspects are decisive. Those references with a focus on the assessment of flexibility for networks were considered. Other references focused on the power system balance such as [7], [8] or [9] were not taken into consideration.

A. METHODOLOGIES

Traditional network planning studies consider the worst-case scenario and apply deterministic methods. With flexibility services, a greater number of scenarios must be considered, which require probabilistic or stochastic approaches. This vision can be applied to the modelling of uncertainties in the performance of flexibility solutions, traditional solutions and even in the calculation of grid requirements. As a result, methodologies can vary greatly and can be applied to different stages of the planning process.

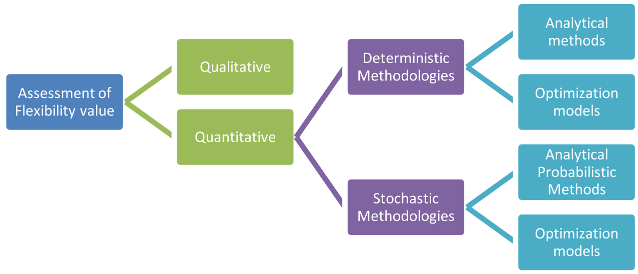

FIGURE 1. Methodologies classification obtained from the literature review Source: Own elaboration.

Methodologies for flexibility evaluation can be categorised as shown in Fig. 1. Some references adopt a descriptive approach with no quantitative calculations. Such is the case of [10], which provides some recommendations on market design and economic requirements for flexibility provision by electric vehicles (EV), or [11] that describes the evaluation mechanisms at the local level. Likewise, [12] proposes a synthesis of the costs and benefits, and [13] evaluates four projects from a qualitative perspective.

Turning to the publications that perform some form of quantitative evaluation, the first group of papers follow deterministic approaches, e.g. [14] performs a thorough cost-benefit analysis of implementing network flexibility for several case studies. Some references use optimisation methods such as in [15] in which the technical potential of flexibility alternatives are evaluated, as a theoretical upper limit for reference costs. Reference [16] applies the sector-coupling model GRIMSEL-FLEX (quadratic dispatch with perfect foresight), to optimize both the flexibility solution and the reinforcement solution simultaneously.

On the other hand, another family of papers implemented analytical stochastic methodologies to model uncertainty. For example, authors in [17] consider probabilities of different demand scenarios in the formulation, obtaining a distribution of flexibility values. Reference [18] evaluated a case study for the United Kingdom using a decision tree with variations in costs and probabilities of flexibility needs. Reference [19] applies an optimization model to a photovoltaic integration case study, minimizing the costs of flexibility. In [20] a real option valuation is performed based on scenario trees and Monte Carlo simulations to optimize grid investments.

Lastly, some publications combine stochastic methods with optimization models. Some of them use meta-heuristics, such as [21] where a genetic algorithm is used to solve a bi-level risk-based optimisation using a stochastic model to consider the uncertainty, or [22] which applies a particle swarm optimization algorithm to optimise flexible resources.

TABLE 1. Literature review and compliance with requirements.

Ref.	Electric mobility	Demand response	Distributed Generation	Mix of drivers	Not specified
[10]	x				
[12]		x			
[13]		x			
[15]		x			
[14]					x
[17]		x			
[18]					x
[19]			x		
[16]				x	
[21]			x		
[22]		x			
[20]					x
[23]					x
[24]		x			
[11]					x

Optimization-based papers present diverse objective functions, ranging from the minimization of the cost of the solution with reinforcement [21], minimization of flexibility costs [19], determination of optimal flexibility requirements [16],or a combination of the former [22].

Likewise, there is a range of optimization methods, which may be equally valid depending on the strategy or data available. Therefore, the methodology framework proposed must fit any type of model to solve and any type of need. Reference [23] proposes a planning framework that integrates different types of algorithms, addressing the entire planning process, including data collection.

This paper proposes an analytical methodology in several stages, under a simplified framework focused on carefully selecting the variables to be considered to make a more accurate assessment. This methodology could be improved, and different optimization methods could be integrated in the treatment of these variables, but before fine-tuning the result, it is necessary to approach the flexibility assessment in an adequate way without neglecting necessary and decisive variables without which it would be meaningless to impose complex optimization methods.

B. DRIVERS CONSIDERED

Network flexibility needs are different depending on their driver, i.e. integrating renewables, electric mobility, demand response, the electrification of other energy uses or a mix of them. As shown in Table 1, the reviewed references tend to target a single specific driver, being demand response the most commonly studied. Many references do not specify a driver, but rather a generic flexibility need without taking into account the specificities of each of them. Only [16] conducts a comprehensive study considering several possible drivers with the purpose of comparing flexibility options, albeit not considering the different grid needs generated.

To make a more accurate assessment of the flexible option, it is necessary to consider the driver that motivates it, both for network planning and operation. Not only because of the new flexibility there may be in reference to that driver, but also because of the network issues that may be created.

The drivers for determining short-term and long-term needs and new grid investments have historically been based on predictions of standard consumption profiles. The drivers of steady demand growth, city planning, or new connection requests will remain relevant. Nonetheless, as shown in [25], decarbonisation efforts bring about new drivers that can be broadly classified into new economic activities, electric mobility, electrification of heating and cooling, resiliency-driven investments, and other new uses of electricity (e.g. industrial processes). Table 2 analyses the old and the new drivers for network development and relates them to their effects and challenges for grid development.

Reference [26] presents a similar comparison as it identifies indicators used to evaluate the planning of the distribution network, sorting them into reliability indicators, economic indicators, coordination between actors and renewable generation connections, all of which are considered in this study. In addition to these indicators, a short list of future challenges is proposed.

C. COSTS AND BENEFITS CONSIDERED

The efficiency of flexibility in comparison to BAU solutions depends on several factors related to the grid, its users, and the flexibility providers. As summarized in Table 3, previous works have considered the following: flexibility costs (calculated or estimated), required investment and expenses to enable flexibility: capital expenditure (CAPEX) and operating expenditure (OPEX) breakdown, the frequency/duration of activations -which is a significant factor in the cost of flexibility, the cost of conventional solutions, and the realistic case study considered.

As shown in Table 3, most of the references propose a quantification for the value of flexibility, while some others do a descriptive analysis, such as [10], [13], [15], and [20]. Only two references [17] and [21] analyze the costs in greater detail by breaking down the Capex and Opex costs. Some others calculate flexible solutions without considering the duration of activation, such as [12], [14], [20] and [24]. Other references considered a very simple calculation of the conventional cost, such as [16], [18], [19], [22], and [23].

In summary, after the literature review, a gap is found to make a detailed analysis of the flexibility costs in order to make an accurate comparison. The flexibility value will depend on costs parameters faced by Flexibility Service Providers (FSPs), system operators and market operator, as well as the costs of the conventional solution, that need to be considered. The methodology must be based on trying to cover the entire possible spectrum of needs, so it must be simple and broad, with the possibility of fine-tuning and optimizing any part of the process.

III. METHODOLOGY: COST DESCRIPTION AND EVALUATION OF FLEXIBILITY SERVICES

The broad-spectrum methodology proposed starts from the type of need, regardless of the driver that motivates it. And then it makes an exhaustive analysis of the costs derived from

TABLE 2. **Drivers for grid investments. Source: own elaboration.**

	Drivers		Effects	Challenges
Traditional Drivers	Ordinary demand growth [30]		Increased energy flows in the grid.	Maintaining electricity supply and reliability levels
	Extraordinary demand growth		New energy flows in the grid. Urban planning.	Integrate new energy withdrawals safely
	Maintain grid reliability [36], [37]		Increasing complexity in ensuring the system reliability	Usually associated with regulatory incentives and a commitment to maintaining technical parameters within established limits
	Environmental concerns. Losses reduction. Cost reduction, other regulatory investments [38]		Different constraints and incentives for grid investments.	Regulatory compliance whilst containing cost levels.
New Drivers	Massive connection of DG [40], [41], [42], [43]		Energy flows in both directions that can generate new challenges for the grid.	Integrate sustainable generation. New planning tools are required.
	Electrification of energy uses	New economic activities (e.g., electrification of industries, hydrogen production)	Unpredicted new energy demands as a consequence of the shift away from fossil fuels and motivated by policies outside the electricity sector	Identify unpredicted demands to do a specific plan for the new energy profile
		Electric mobility [28], [45]	Increase of energy consumption with the possibly high-power requirement but with the flexibility to charge at different times	Incentivise smart charging strategies.
		Electrification of heating and cooling .[48],[49], [50]	Increase of energy consumption with a certain flexibility	Make use of flexibility potential
	Resiliency [53], [54]		Frequent extreme weather events resulting from climate change	Maintaining continuity of the service and reliability at the required levels

TABLE 3. **Literature review on valuing DSO flexibility.**

Ref.	Flex value quantification	Breakdown in CAPEX and OPEX	Duration of activations	BAU solution considered	BAU cost calculation	Realistic case study
[10]				x		
[12]	x			x		
[13]						
[15]				x		x
[14]	x			x		x
[17]	x	x	x	x	x	x
[18]	x		x	x		x
[19]	x		x			x
[16]	x					
[21]	x	x		x	x	x
[22]	x		x	x		x
[20]						
[23]	x		x			x
[24]	x					

the necessary flexibility solution, since the type of solution will depend on the type of need, as concluded in [27]. Assessing the cost competitiveness of flexibility is not a simple task since, as mentioned in [28], casuistry is very diverse and highly country specific. Following this methodology, the competitiveness of flexibility versus BAU is quantified and evaluated. Afterwards, by selecting use cases related to some relevant drivers in the energy transition, it is possible to make a comparative analysis of various needs and various flexibility solutions following the same methodology.

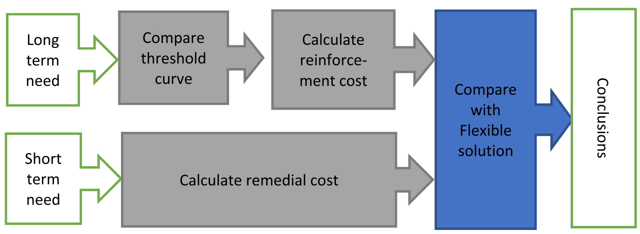

FIGURE 2. **Methodology for comparing BAU and flexibility solutions. Source: own elaboration.**

A. COSTS COMPARISON DEPENDING ON THE NEEDS

The needs of the network can be divided into long-term needs and short-term needs as indicated in [27]. For long-term needs, network reinforcements are compared with flexibility services, considering the risk of not reinforcing addressed in section B. However, for short-term needs, the comparison is not made with the reinforcement cost, but with the cost of the corresponding remedial action. Fig. 2 shows this methodology. The different steps could include optimization functions, whether for the calculation of the best reinforcement solution, the calculation of the best flexibility solution, or the calculation of the network requirements by means of an optimal power flow (OPF). Indeed, all the costs considered can be studied and optimized. However, there is a preference for separating the methodology from the optimisation methods that may exist in any part of the process, as can be seen in [11] or [18].

B. RISKS OF NOT REINFORCING AND NOT CONTRACTING FLEXIBILITY

As studied in [28], reinforcing the network or contracting flexibility are not the only options. A third alternative would be to accept the risks of not contracting flexibility, nor reinforcing the grid.

This risk is difficult to model because it involves making a trade-off between the reliability of the network and the risk that the DSO wants to or can assume. It therefore depends on its strategic decisions. However, it is assumed that small punctual overloads in the distribution network are acceptable and do not affect the useful life of the assets [29].

The longer the duration of the overload or the larger the overload, even of short duration, the more unacceptable the risk becomes. This risk can be modelled with a time-load curve similar to the time-current one used by protective devices [30].

In [29] a relationship between Load and Duration is established based on equal risk criterion. Different curves are defined depending on whether it is planned or emergency loading. These threshold curves (TC) depend on the strategy and according to its shape, it is proposed to be assimilated as a logarithmic curve as presented in (1) or in (2):.

$$\boldsymbol{h} = \boldsymbol{\beta} + \mathbf{log}_{\boldsymbol{\theta}}\,(\boldsymbol{\alpha} - \mathbf{P})\,;\,(\theta > 1) \tag{1}$$

$$\mathbf{P} = \boldsymbol{\alpha} + \boldsymbol{\theta}\hat{\ }(\boldsymbol{\beta} - \boldsymbol{h}) \tag{2}$$

where:

- $\boldsymbol{\alpha}, \boldsymbol{\beta}, \boldsymbol{\theta}$ are constants that determine the shape of the curve and that depend on the strategy. $\boldsymbol{\alpha}, \boldsymbol{\beta}$ allocate the curve in reference to the axis, which is useful to adjust the strategical situation as in Fig. 3 (emergency or long term), and $\boldsymbol{\theta}$ will define the slope and has to be more than one and positive, which will depend on the type of asset and the number of overloading hours that can support. A smaller $\boldsymbol{\theta}$ will determine a steeper curve and therefore a greater sensitivity to overloading. For example, an underground line would present a lower $\boldsymbol{\theta}$ than an overhead line.
- $\boldsymbol{P}$ is power in MW.

In the long term, this curve is not calculated for the purpose of obtaining the cost, but to have a threshold from which no action beyond the monitoring of the asset would be necessary. The scenarios presented in the previous figure on planned loading or emergency loading are measures that have to be configured depending on the risk to be taken by the DSO. Therefore, for the long term in this section no cost is considered. The DSO strategy considers a limit of hours below which neither flexibility services nor network reinforcement are necessary. When the load gets closer to this value, the network requires a planning action in line with the evolution of the need.

As can be seen in Fig. 3 different curves can be proposed depending on the risk that the DSO wants to assume. When alpha is high, the DSO assumes the risk of long-lasting high overloads, which is an operational decision that depends on the different risks to be assumed in different scenarios, configuring emergency scenarios or planning scenarios as proposed in [29]. Depending on the position of the threshold curve (TC), as long as it is above the Use Duration Curve (UDC), analogue as the Load Duration Curve (LDC), a certain value can be chosen. Thus, this curve may be completely above the UDC (when there is not enough saturation), or completely below the UDC (when a flexible solution or reinforcement is very necessary).

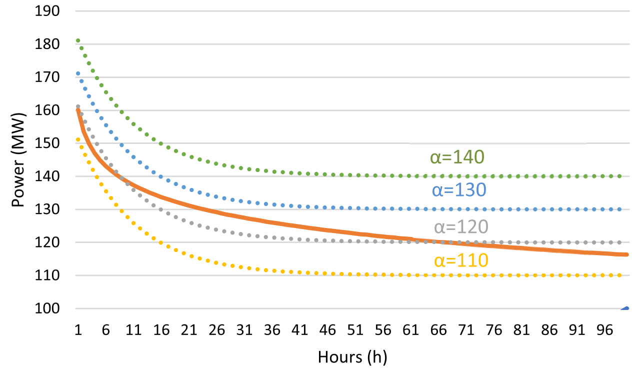

FIGURE 3. Threshold Curves TCs in dotted lines for no actions depending on the strategy (changing α which determines the admissible load for loads lasting many hours). In continuous line an expected UDC. In more emergency situations, greater limit curves will be considered and in more ordinary situations, lesser limit curves will be considered. Source: own elaboration.

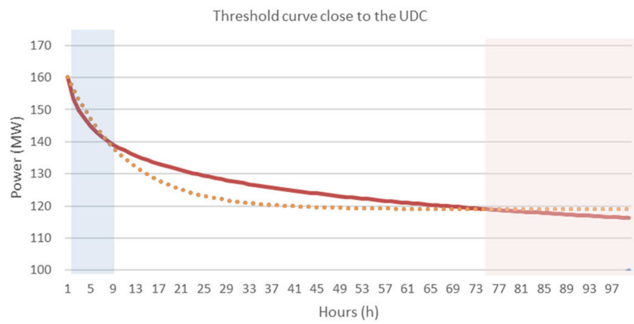

FIGURE 4. UDC close to the TC (dotted): There are different zones where no actions are considered: when being a few hours of overload or when being low overload. Source: own elaboration.

In some cases of mixed situations are possible as shown in Fig. 4 that, depending on the number of hours of need, long-term solutions are considered.

In the case that UDC and CT intersect more times, the most relevant intersection is the one that always has the TC curve above the UDC on the right. This point determines the number of hours that need to be considered as critical.

In short-term operational needs scenarios, the risk of temporarily overloading certain elements may be more bearable, especially because short-term needs can hardly be covered by network reinforcements. However, the remedial actions that can compete with flexibility solutions are different for each type of network. For example, for the work of replacing a transformer in a secondary substation due to failure or maintenance, a mobile generator can be installed so that customers do not suffer the interruption. The cost of installing a larger or smaller generator would compete with the flexibility offer. For this reason, there may occasionally be a cost to transcend this threshold in the short term.

C. FLEXIBILITY COSTS DESCRIPTION

The calculation of the cost of a specific flexibility service follows the equation (3). This description is more complete than the one carried out in [22], which only considers flexibility activation costs. Following the same equation, the values vary depending on the service.

$$\begin{aligned} Cost_{n,s}^{flex} &= O_{n,s}^{\mathrm{DSO\ Op}\ flex} + O_{n,s}^{\mathrm{DSO\ Pl}\ flex} + C_{n,s}^{\mathrm{Enab}\ flex} \\ &\quad + Cost_{n,s}^{\mathrm{Mkt}\ flex} + Cost_{n,s}^{\mathrm{Agg}\ flex} \end{aligned} \tag{3}$$

where:

- $Cost_{n,s}^{flex}$ is the annual cost (year n) of using a flexibility service s, including CAPEX and OPEX.
- $O_{n,s}^{\mathrm{DSO\ Op}\ flex}$ is the OPEX Operation cost (year n) for the DSO in year n of using a flexibility service.
- $O_{n,s}^{\mathrm{DSO\ Pl}\ flex}$ is the OPEX Planning cost (year n) for the DSO in year n of using a flexibility service.
- $C_{n,s}^{Enab\ flex}$ is the CAPEX Enabling cost (year n) for the DSO in year n of using a flexibility service.
- $Cost_{n,s}^{\mathrm{Mkt}\ flex}$ is the Market cost (year n) of using a flexibility service.
- $Cost_{n,s}^{FSP\ flex}$ is the payment (year n) to the FSP for proving a flexibility service. Also including CAPEX and OPEX as there is an investment to be made by the flexibility provider.

A description of each term of the equation follows below.

1) DSO: OPEX AND CAPEX

Operating costs are separated from the planning costs (i.e. the costs of long-term requirements).

a: OPERATION OPEX COSTS

Based on the study conducted in [28], which considers Opex and Capex costs for every option; but also on other studies such as [31], with the same approach but comparing coordination schemes; [17], considering all relevant factors the annual costs of flexibility; and [22], with the methodology approach. The calculation follows the equation (4).

$$O_{n,s}^{\mathrm{DSO\ Op}\ flex} = \mathbf{h} \times O_{n,s}^{\mathrm{DSO\ Op}\ Activ} + \mathbf{fsp} \times O_{n,s}^{\mathrm{DSO\ Op}\ FSP} \tag{4}$$

where:

- **h** are the hours of activation
- $O_{n,s}^{DSO\ Op\ Activ}$ is the cost for activation duration for the DSO
- **fsp** is the number of resources which provide the service
- $O_{n,s}^{\mathrm{DSO\ Op}\ FSP}$ is the cost per FSP for the DSO.

These costs will be mainly linked to the costs associated with the prequalification process, the studies of short-term alternatives and monitoring. This cost will mainly depend on the hours of activations and the number of resources enabled.

The number of activations in hours may be calculated depending on the DSO's needs at any given time as shown in [23] or in [32]. For this purpose, for long-term congestion needs is useful to obtain a function of the UDC of the congested element. For other types of needs, for reactive power or voltages for example, the same method would apply. This data is necessary input for network planning, an optimized curve is assumed for each hour of network operation. To treat these curves it is necessary to filter out possible outliers due to extraordinary situations in the network.

The UDC is used for the calculation of network requirements. By observing that the format of the curve for different real cases is similar, a logarithmic formulation is adjusted to the following formula.

$$\mathbf{P} = -\mathbf{A} \times \mathbf{lnh} + \mathbf{B} \tag{5}$$

where:

- **P** is the power limit
- ***h*** is the hours of activation
- **A** and **B** are constants that depend on the load forecast

According to it, equation (4) can be re-written as:

$$\begin{aligned} h = \mathrm{e}^{\wedge}((B-P)/A);\ O_n^{\mathrm{DSO\ Op}\ flex} &= \mathrm{e}^{\wedge}((B-P)/A) \\ \times O_n^{\mathrm{DSO\ Op}\ Activ} + \mathbf{fsp} \times O_n^{\mathrm{DSO\ Op}\ FSP} \end{aligned} \tag{6}$$

b: PLANNING OPEX COSTS

As for the planning process, the equation is as follows:

$$O_n^{\mathrm{DSOPl}\ flex} = \mathbf{R} \times O_n^{\mathrm{DSO\ Pl}\ FSP} \equiv k \times \mathbf{fsp} \times O_n^{\mathrm{DSO\ Pl}\ FSP} \tag{7}$$

where:

- **R** is the number of requests for connecting new resources that are referred to the service. This number is closely related to **fsp** and can be considered proportional to the service.
- $O_n^{\mathrm{DSO\ Pl}\ FSP}$ is the cost per FSP.

Planning costs are linked mainly to the costs associated with cost-benefit studies of long-term alternatives and the definition of the need for investing in the network. Therefore, these costs depend on the number of requests and not so much on the activation.

c: ENABLING OPERATION AND PLANNING. CAPEX COSTS

Enabling costs refer to those necessary for the software and hardware required to start using flexibility. These are the most significant costs since enabling the solution requires putting in place tools for managing flexibility, monitoring, and managing data that are not necessary with traditional solutions. On the other hand, there is an initial cost to start the process and an annual cost to maintain it. The initial cost also includes monitoring and data management, training, and communication.

In terms of annual costs, maintenance and improvement costs of these tools are considered:

$$C_{n,s}^{Sunk\ flex} = C_{n,s}^{Plat\ flex} + C_{n,s}^{Mon\ flex} + C_{n,s}^{Dat\ flex} \tag{8}$$

where:

- $C^{\mathbf{Plat}\,flex}_{n,s}$ is the annual cost of maintaining and improving the platforms. In this case, the operation and planning platforms for the calculation of the needs are included.
- $C^{\mathbf{Mon}\,flex}_{n,s}$ is the annual cost of the monitoring infrastructure, including real-time data and set points.
- $C^{\mathbf{Dat}\,flex}_{n,s}$ is the annual cost of the data management infrastructure, including sharing and acquisition platforms and data processing.

2) MARKET: OPEX AND CAPEX

As for the market costs, the equation is as presented in (9):

$$Cost^{\mathbf{Mkt}\,flex}_{n,s} = \sum O^{\mathbf{Clm}}_{i} + C^{\mathbf{CAPEX\ Mkt\ Sys}}_{n} \tag{9}$$

where:

- $O^{\mathbf{Clm}}_{i}$ is the OPEX cost for all services of the long-term and short-term market clearing, validation market data, receive information from the prequalified units, receive flexibility Long-Term and Short-Term needs from DSO, Open the market and inform flexibility needs and Receive flexibility offers.
- $C^{\mathbf{CAPEX\ MKT\ Sys}}_{n,s}$ is the CAPEX annualized cost of the calculation of baselines, interfaces to SO platforms, best procurement strategy deployment (auction / market) and communication with the rest of market platforms (balancing, congestion…)

$C^{\mathbf{CAPEX\ MKT\ Sys}}_{n,s}$ is expected to be significantly higher than $O^{\mathbf{Clm}}_{i}$, since it represents the entire investment in the market. The value $O^{\mathbf{Clm}}_{i}$is also proportional to the number **fsp**, as it defines the maximum number of bids.

$$O^{\mathbf{Clm}}_{i} \equiv \mathbf{fsp} \times O^{\mathbf{Clm}}_{i,s} \tag{10}$$

where:

- $O^{\mathbf{Clm}}_{i,s}$ is the OPEX cost for a specific service **s** of the long-term or short-term market clearing, validation market data, receive information from the prequalified units, receive flexibility long-term and short-term needs from DSO, Open the market and inform flexibility needs and receive flexibility offers.

3) FLEXIBILITY SERVICE PROVIDER: OPEX AND CAPEX

As for the FSP costs, the costs are presented in (11).

$$Cost^{\mathbf{Agg}\,flex}_{n,s} = \sum C^{\mathbf{FSPm}}_{i,s} + \sum O^{\mathbf{Actm}}_{j,s} + C^{\mathbf{CAPEX\ Agg\ Sys}}_{n,s} \tag{11}$$

where:

- $C^{\mathbf{FSPm}}_{i,s}$ is the OPEX cost of receiving scheduling data from generators, consumers, and flexibility Prediction
- $O^{\mathbf{Actm}}_{j,s}$ is the OPEX cost of calculation of flexibility bids, long-term & short-term flexibility activation, procurement of flexibility, real time flexibility activation and real-time monitoring.
- $C^{\mathbf{CAPEX\ Agg\ Sys}}_{n,s}$ is the CAPEX annualized cost of the operation platforms, data management, flexibility prediction tools, data acquisition from DERs, communications and interface to market platforms

As in previous cases, is proportional to the number of FSPs and is proportional to the number of activations in hours as presented in (12):

$$C^{\mathbf{FSPm}}_{i,s} \equiv \mathbf{fsp} \times Agg^{FSPm}_{i,s} \tag{12}$$

where:

- $Agg^{\mathbf{FSPm}}_{i,s}$ is the OPEX cost to receive scheduling data from generators, consumers, and flexibility prediction for a specific service **s**

And

$$O^{\mathbf{Actm}}_{s} \equiv \mathbf{h} \times O^{\mathbf{Actm}}_{j,s} \tag{13}$$

where:

- $O^{\mathbf{Actm}}_{j,s}$ is the OPEX cost of calculation of flexibility bids, long-term & short-term flexibility activation, procurement of flexibility, real time flexibility activation and real-time monitoring for a specific service.

4) FLEXIBILITY COST FORMULA

Taking into account all the values and proportionalities deduced in the previous subsections, (14) can be deduced:

$$Cost^{flex}_{n,s} = \sum \mathbf{h} \times Cost^{\mathbf{Act}}_{i,s} + \sum \mathbf{fsp} \times Cost^{\mathbf{fsp}}_{i,s} + Cost^{Enab} \tag{14}$$

And for the long-term the equation is as in (15):

$$Cost^{flex}_{n} = \sum \mathrm{e}\hat{\ }((B-P)/A) \times Cost^{\mathbf{Act}}_{i,s} + \sum \mathbf{fsp} \times Cost^{\mathbf{fsp}}_{i,s} + Cost^{Enab} \tag{15}$$

where:

- $Cost^{\mathbf{Act}}_{i,s}$ is the total cost that is proportional to the hours of activation.
- $Cost^{\mathbf{fsp}}_{i,s}$ is the total cost that is proportional to the number of **FSP**.
- $Cost^{Enab}$ is the total cost that do not depend on the hours of activations or FSP participants in the service and remains constant for a year.
- **P** is the power limit
- **A** and **B** are constants that depend on the load forecast.
- **fsp** is the number of resources that are referred to the service

Since it will not be possible to manage the enabling costs at the time of the comparison, the flexibility costs is considered once the service has been enabled, and will therefore correspond to the following formula in (16):

$$Cost^{flex}_{n,s} = \sum \mathbf{h} \times Cost^{\mathbf{Act}}_{i} + \sum \mathbf{fsp} \times Cost^{\mathbf{fsp}}_{i,s} \tag{16}$$

And for the long-term is as in (17)

$$Cost^{flex}_{n,s} = \sum \mathrm{e}\hat{\ }((B-P)/A) \times Cost^{\mathbf{Act}}_{i,s} + \sum \mathbf{fsp} \times Cost^{\mathbf{fsp}}_{i,s} \tag{17}$$

5) LIST OF NOTATIONS

As a summary for a better understanding of the costs considered in this section, Table 4 shows the notations used in it.

IV. CASE STUDIES FOR EVALUATION OF FLEXIBILITY SOLUTIONS

As mentioned in section B, the selection of representative cases is triggered by new flexibility drivers. Fig. 5 summarizes the realistic case studies selected and their main characteristics.

All four case studies are based in network situations with realistic parameters from Spanish grids and compatible with the values in the Joint Research Center (JRC) DSO Observatory publications [33], [34], and [35].

Regarding large-scale DG connection, two scenarios are chosen for the two renewable technologies that have proliferated the most: photovoltaic generation and wind generation. These are the two most relevant technologies in the case of Spain, where the National Energy and Climate Plan (NECP) [36] foresees 62 GW will come from wind energy and 76 GW from solar photovoltaic. Both technologies already represent a high installed capacity in 2022 (27.5GW of wind and 13.6GW of photovoltaic, PV).

Photovoltaic capacity has increased almost 3 times in Spain in four years [37], and wind generation connected to the distribution grid has become the first source of electricity in the country [38].

In the case of electromobility, the number of vehicles has increased fourfold in the last four years [39] and the NECP also foresees a boost for electric vehicles [36]. This rate is higher than the electrification of other processes or heating and cooling. The resilience case completes the list of case studies considering a short-term need in the network caused by a temporary asset unavailability. This situation is not new, although it may be more frequent in the case of extreme weather conditions depending on the fragility of the grid [40].

All the case studies presented are framed in the Spanish context, considering the Spanish distribution networks, which according to the network characteristics described in [34] could be broadly representative for most of the European Union, which also have ambitious targets in their NECP [41].

For calculating reinforcement costs, the unit costs set in [42] by the Spanish regulator is considered. This is a public cost reference used by the regulator. The solution considered is based on a real network.

To perform the evaluation, the cost of investments related to BAU solutions are obtained from the information of different technologies that the Spanish regulator published in 2015 [43]. Since many costs are CAPEX, in order to annualise these costs, a WACC (Weighted Average Cost of Capital) of 5% has been considered to levelize the investment over the useful life, which is considered of 40 years following [43]. Regarding remedial BAU costs, an average Value of Lost Load (VoLL) of 7.9€/kWh is also considered [44] that provides a baseline for Spain. Similar values are found in [45], [46], and [47]. In all cases, there is a relevant component of CAPEX considered as sunk cost which relates to investment

TABLE 4. Notations related to costs description.

Notation	Units	Variable description
$Cost_{n,s}^{flex}$	Monetary unit (€)	Annual cost (year n) of using a flexibility service s, including CAPEX and OPEX
$O_{n,s}^{DSO\ Op\ flex}$	Monetary unit (€)	OPEX Operation cost (year n) for the DSO in year n of using a flexibility service s
$\mathbf{h}$	Hours (h)	Hours of activation of the flexibility service
$O_{n,s}^{DSO\ Op\ Activ}$	Monetary unit (€)	Cost for activation duration for the DSO
$\mathbf{fsp}$	Number	Number of resources which provide the service
$O_{n,s}^{DSO\ Op\ FSP}$	Monetary unit (€)	Cost per FSP for the DSO
$O_{n,s}^{DSO\ Pl\ flex}$	Monetary unit (€)	OPEX Planning cost (year n) for the DSO in year n of using a flexibility service.
$C_{n,s}^{Enab\ flex}$	Monetary unit (€)	CAPEX Enabling cost (year n) for the DSO in year n of using a flexibility service
$\mathbf{R}$	Number	Number of requests for connecting new resources that are referred to the service
$O_{n}^{DSO\ Pl\ FSP}$	Monetary unit (€)	Cost per FSP
$C_{n,s}^{Sunk\ flex}$	Monetary unit (€)	Annual cost of enabling the flexible solution
$C_{n,s}^{Plat\ flex}$	Monetary unit (€)	Annual cost of maintaining and improving the platforms
$C_{n,s}^{Mon\ flex}$	Monetary unit (€)	Annual cost of the monitoring infrastructure, including real-time data and set points.
$C_{n,s}^{Dat\ flex}$	Monetary unit (€)	Annual cost of the data management infrastructure, including sharing and acquisition platforms and data processing.
$Cost_{n,s}^{Mkt\ flex}$	Monetary unit (€)	Flexibility market platform operating costs
O_{i}^{Clm}	Monetary unit (€)	OPEX cost for all services of the long-term and short-term market clearing, validation market data, receive information from the prequalified units, receive flexibility long-term and short-term needs from DSO, open the market, inform flexibility needs and receive flexibility offers.
$C_{n}^{CAPEX\ Mkt\ Sys}$	Monetary unit (€)	CAPEX annualized cost of the calculation of baselines, interfaces to SO platforms, best procurement strategy deployment (auction / market) and communication with the rest of market platforms (balancing, TSO congestion management)
$Cost_{n,s}^{Agg\ flex}$	Monetary unit (€)	Flexibility Service Provider and Aggregator costs
$C_{i,s}^{FSPm}$	Monetary unit (€)	OPEX cost of receiving scheduling data from generators, consumers, and flexibility Prediction
$O_{j,s}^{Actm}$	Monetary unit (€)	OPEX cost of calculation of flexibility bids, long-term & short-term flexibility activation, procurement of flexibility , real time flexibility activation and real-time monitoring.
$C_{n,s}^{CAPEX\ Agg\ Sys}$	Monetary unit (€)	CAPEX annualized cost of the operation platforms, data management, flexibility prediction tools, data acquisition
$Agg_{i,s}^{FSPm}$	Monetary unit (€)	OPEX cost to receive scheduling data from generators, consumers, and flexibility prediction for a specific service s

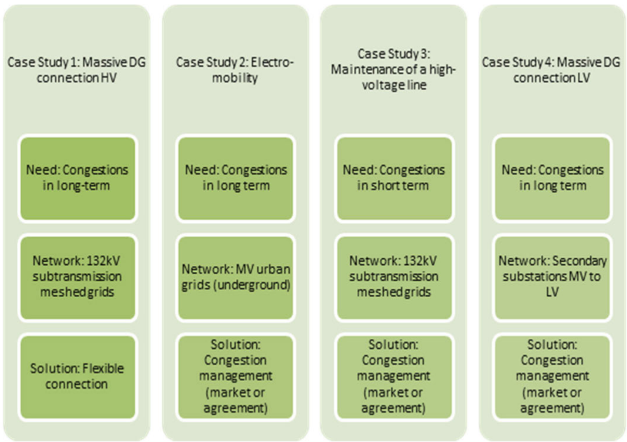

FIGURE 5. **Summary of realistic case studies selected based on a Spanish distribution grid.**

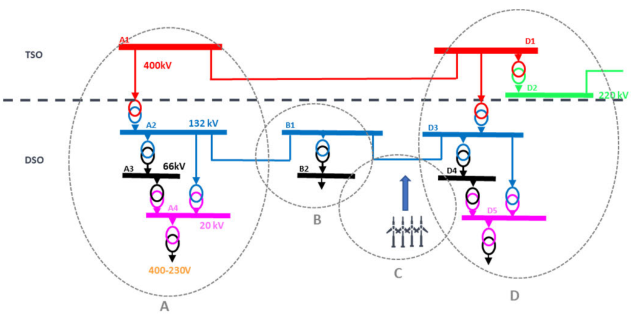

FIGURE 6. **Single-line diagram of a new flexible connection. Red and green colors represent TSO voltage levels, and blue and black are related to sub-transmission voltage levels (operated by the DSO in this case). Source: i-DE (Spanish DSO).**

in operating platforms, data exchange links between platforms and tools for flexibility management, planning and operation with flexibility, baseline calculation, market clearing, among others.

On the other hand, the cost of the traditional solution is also constant and independent of the hours of activations and the number of FSP for a given year. This cost is also calculated considering different scenarios that are not always comparable with a single flexible solution, so it is convenient to consider a fixed value of the traditional solution.

A. CASE STUDY 1: MASSIVE DG CONNECTION IN HV. NEW FLEXIBLE CONNECTION TO SUB-TRANSMISSION GRID OF RENEWABLE GENERATION

As discussed above, allowing the connection of more generation capacity that the grid can evacuate at any time without reinforcement requires Active Network Management (ANM). A flexible connection as a connection agreement described in [48] requires a service from the DSO, which would go to ''no-fit, don't forget'' and would require monitoring and control of the limits by the DSO.

Some ongoing pilots are considering ANM with different approaches such as in [49] or [50] in the United Kingdom. Limitation control and active management are carried out automatically and require some investment to automate the execution of the algorithms. Note that the limitation control can also be done manually in those cases where the investment of automating the solution is not more efficient than the manual solution itself.

1) GRID DESCRIPTION AND IDENTIFICATION OF THE NETWORK NEED

The case of manual management is considered as an example. Due to the high penetration of generators in an area (grid between city A and city D in Fig. 6) there is a risk of overloading a 132kV sub-transmission line, which is occasionally open to avoid energy transfers that may occur when the 400kV line between A and D is open.[1]

In this case, where the transmission line runs parallel to the distribution line without any branches, the operation of TSO and DSO requires special coordination. Any manoeuvres in the network should not cause congestion at any level. That is why a request for the connection of a new 50MW generator at point C in Fig. 6 would require to build a grid reinforcement in the 132kV network. The reinforcement required is costly, and the execution time is long, amounting to several years. This situation exceeds the thermal limit set for that system by 7.5MW. Therefore, there is a possibility to allow this wind farm to connect before building the reinforcement while the thermal limit is monitored and not violated by the impact of the wind farm by doing active management of the generation.

2) BUSINESS AS USUAL SOLUTION

The TC provided by the DSO is:

$$h = \beta + \log_\theta (\alpha - \mathbf{P}) = -\log_{1,23} (\mathbf{P} - 120) \tag{18}$$

Which is below the power needed as can be seen in Fig. 8, so either reinforcement or a flexible solution is needed.

To maintain the reliability levels of the network and to connect directly to substations in B and D and not jeopardize the current line running between them, the BAU solution would be (see Fig. 7):

- Construction of a 132kV to 20kV substation for power evacuation (this reinforcement is necessary to connect to the grid)

- Construction of two 132kV lines from B to C and from C to D with a total distance of several tens of kilometers.

- Modification of substations B and D to connect the new lines.

a: BAU SOLUTION COST

The costs for a new connection with the BAU approach would be 6,333,000€, obtained as follows:

- Construction of two 132kV lines:

30km x 183,547€/km (code TI-1UX in [42]) = 5,506,410€

[1]In Fig. 6, if A1-D1 line is open, energy from A1 to D1 may go through A2, B1 and D3.

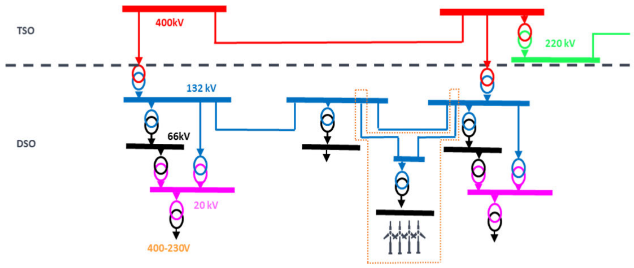

FIGURE 7. Single-line diagram for new connection including reinforcements. Source: i-DE (Spanish DSO).

- Modification of substations B and D to connect the new lines.

2 Bays 132kVx 413,270€/bay (code TI-91U in [42]) = 826,540€

The lifetime of this investment is considered to be 40 years [43] and annualising the cost considering a WACC of 5% gives an annualised cost of 369,075.59€.

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

According to the framework in [27], the case of the flexible connection is based on a bilateral agreement. This agreement establishes the periods in which power curtailment is necessary to ensure compliance with grid requirements. These periods must be agreed based on a long-term forecast, as it is intended to be compared with a reinforcement of the grid.

Fig. 8 shows the number of hours per year that are needed for wind generation to be curtailed. In this case the UDC and TC intersect only once. By sorting the hours of one year from highest load to lowest load in descending order, the hours in which a solution is necessary are obtained. These hours are the ones exceeding the maximum of the 132kV line capacity considering the generation and load curve in the energy flow in that line. This analysis results 68 hours of curtailments of 7.5MW during working days. The resulted curtailment would be based on the actual needs and for all hours when congestions are forecasted.

a: FLEXIBILITY SOLUTION COST

The annual cost of the flexibility service is assessed on the basis of the methodology explained above. CAPEX costs are mainly sunk costs in terms of DSO and market. Annual operating costs per fsp are considered as Prequalification (2.5h), Registration (2.5h), Planning costs as Cost Benefit Analysis (10h) and Definition of scenarios (10h). Annual operating costs per activation hour are: Monitoring (1h per activation h), Billing (1h per activation h) and Needs Calculation (1h per activation h). All costs are based on person-hours. An automated solution would only be incorporated if it is more efficient than a non-automated solution. The value of hours has been based on [51], considering the salary of an industrial engineer newly recruited plus corresponding employment charges in Spain [52].

In this case, a market is not necessary. Finally, in terms of Aggregation and FSP costs, operational expenses for

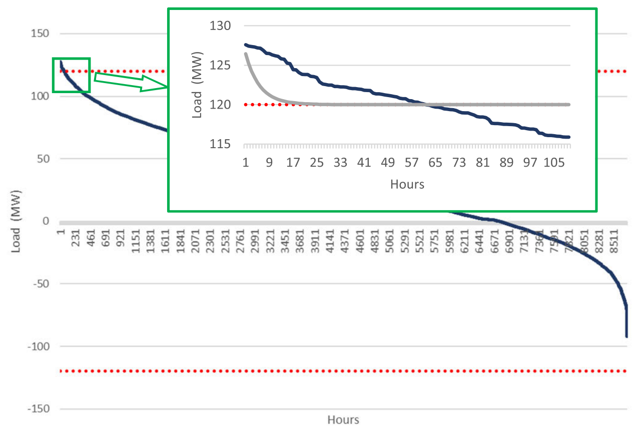

FIGURE 8. Load Duration Curve in blue of a 132kV line for one year. Calculation of the hours to be curtailed. The TC can be seen in grey in the zoom. Source: I-DE (Spanish DSO).

monitoring and energy costs and some investments in communications and data acquisition are considered (200€from the values used in CoordiNet [4]).). Despite the volatility to which the electricity market may be subject, a reference has been sought and a price of the energy of 40€/MWh has been considered as in [53].

With all this:

$$\begin{aligned}\boldsymbol{Cost_1^{Act}} &= (1+1+1+2)\,h \times \frac{40000€}{1760h} \\ &\quad + 40€/MWh \times 7.5MW = 413.63€ \\ \boldsymbol{Cost_1^{fsp}} &= (2.5+2.5+10+10)\,h \times \frac{40000€}{1760h} \\ &\quad + 200€ = 768.18€\end{aligned}$$

From the UDC curve, the constants A and B are calculated:

$$\begin{aligned}\boldsymbol{Cost_n^{flex}} &= \boldsymbol{e}^{\frac{\mathbf{160.17-P}}{\mathbf{9.534}}} \times \boldsymbol{Cost_1^{Act}} + \boldsymbol{Cost_1^{fsp}} \\ &= \boldsymbol{e}^{\frac{\mathbf{160.17-P}}{\mathbf{9.534}}} \times 413.63 + 768.18 = \mathbf{28,\,722.56€}\end{aligned}$$

4) COMPARISON AND SENSITIVITY ANALYSIS

The main benefit of this action is actually accelerating the renewables integration and the transition to a more sustainable generation mix. The economic impact in terms of emissions reduction or other benefits could be addressed, but it is out of the scope of this analysis which focuses on the distribution system costs. Therefore, in this case the investments costs include connection costs, even if this cost is borne by the developer.

a: COMPARISON

Table 5 summarizes the assessment of the case 1.

The solution with flexibility is clearly cheaper, only a significant lower reinforcement cost could reverse this situation. Another benefit associated with this solution is the anticipation of the connection in the period when the reinforcement is being executed. In this case, it is necessary to consider the life span of the generation facility itself, the grid extension to connect such a facility and the corresponding reinforcement. The value in producing earlier in time could be significant.

TABLE 5. Costs assessment for new flexible connections.

Business As Usual: Reinforcement			Alternative with a flexibility service	
Investment cost	Years	Annual cost	Hours of activation	Annual Cost
6,333,000€	40	369,075.59€	68	28,722.56€

For instance, for a 1500h/year production of 50MW, even with curtailment, at an average price of 30€/MWh it would mean 2.25M€ per year.

b: SENSITIVITY ANALYSIS

If the required curtailment activation is larger, it could reach the reinforcement value. These conditions a priori should not change as the grid circumstances do not change. But the solution with flexibility is almost proportionally linked to the cost of energy, valued at 40€/MWh. With market prices in 2022, which are often several times higher, the flexible solution could be unfeasible. Market volatility would therefore call into question short-term market solutions for long-term needs. For this particular use case, if the energy price rises up to 712€/MW, the break-even point is found.

On the other hand, the BAU solution is also influenced by network needs and the distances of new lines. In this case, halving the number of line kilometers would also lower the cost of the BAU solution almost proportionally.

B. CASE STUDY 2: ELECTRO MOBILITY. CONGESTION ON MV NETWORK AS A RESULT OF ELECTRIC VEHICLE CHARGING

1) GRID DESCRIPTION AND IDENTIFICATION OF NEEDS

In this case, potential grid congestion is considered in the case of incorporating electric vehicle charging points. The grid to be considered is shown in Fig. 9. It represents a consolidated urban area.

Fig. 9 shows a 20 kV feeder that departs from a primary substation and travels through seventeen secondary substations over a distance of 10 km (compatible with a median 0.73km per MV supply point in [33]) until it reaches a switching centre where it is normally operated open on arrival. Several 20kV feeders with similar characteristics arrive at the switching centre.

Each secondary substations feeds several residential buildings, offices, shops, and commercial buildings. With an average of 200 customers per secondary substation (compatible with 0.95 percentile of 209 consumers per MV/LV substation in [33]), 90% are domestic. According to [54] and [55], and especially to [56] for typical load profiles, the usual peak load in Spain for this type of consumer would occur between 18:00 and 20:00 when both businesses and homes consume energy. If electric vehicles demand can be shifted, it is expected that the peak demand for charging occurs at that time.

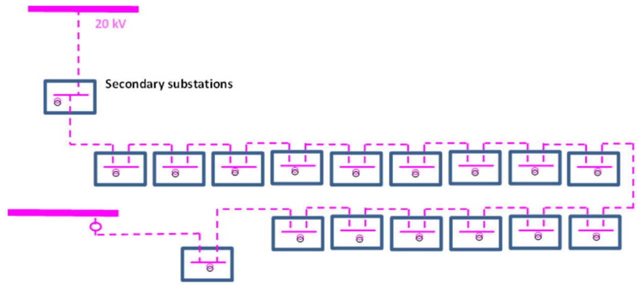

FIGURE 9. One-line diagram of simplified MV i-DE network representation. Source: i-DE (Spanish DSO).

The maximum load of the feeder in the year is 6MW. The capacity of the feeder is 12MW (240mm2), as the operation of the feeder is not at its nominal capacity due to the probability of failure. The load is only increased to support other feeders that may need it due to contingencies. In this case, an additional load of 4MW is expected.

The assumptions made in this case are related to the increasing demand for electric vehicles charging.

2) BUSINESS AS USUAL SOLUTION

No TC was provided in this case as the power needed largely exceeds the capacity limits. Assuming that half of the residential consumers have an electric vehicle charger and demand an average of 3.5 kW, (that would be a single-phase charging at 16A at LV, typical of a domestic slow charging point and compatible with contracted peak power 5.9 kVA per LV consumer in [33])for charging at peak times, consumption would double. Therefore, it would be necessary to reinforce the grid to alleviate this increase in load.

The reinforcement needs, highlighted in red in Fig. 10 are: - Increase in transformer power at substation C (in Fig. 10). This increase is expected to be the same in the rest of the adjacent areas. Therefore, increasing transformer power to 20kV at one substation would alleviate the problem at several neighbouring substations. For that reason, to make a proportional distribution of the costs, a 10% of the cost of a complete transformer substation is estimated. - New feeder with a distance of 10km, which may not be the shortest route considering urban constraints. - Reinforcement of the secondary substation to connect the new feeder.

a: BAU SOLUTION COST

The costs for the reinforcement would be 1,656,700€, obtained following three steps described below.

1. Increase in transformer power at the substation (10% of the cost):

0.1 × 16,610€(code TI-163V in [42]) = 1,661€1Bay 20kV x 77,657€/bay (code TI-105V in [42]) = 77,657€

2. New feeder with a distance of 10km.

10km x 155,456€/km (code TI-18UY in [42]) = 1,554,560€

3. Reinforcement of the secondary substation to connect the new feeder.

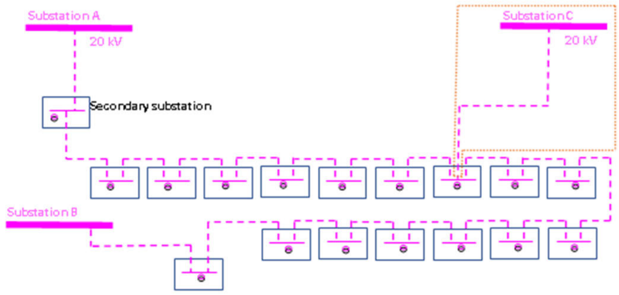

FIGURE 10. **Single-line diagram of simplified MV i-DE network representation including reinforcement (area in red). Source: i-DE (Spanish DSO).**

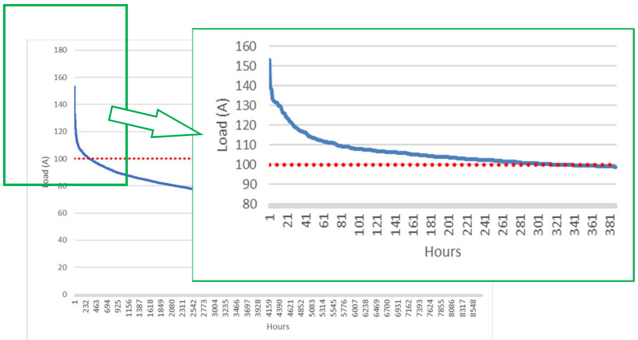

FIGURE 11. **Load Duration Curve of a MV line for one year. Calculation of the hours to be curtailed in the MV line during a year. Some extreme data refer to anomalous network situations. Source: i-DE (Spanish DSO).**

1 switching station x 22,818€/station (code TI-0CW in [42]) = 22,818€The lifetime of this investment is considered to be 40 years [43] and annualising the cost considering a WACC of 5% gives an annual cost of 96,549.43€.

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

The case of electric mobility would be eligible for different mechanisms according to [27] depending on the liquidity and the possibility of having dynamic tariffs as it is a generalised situation across the area. The recurrent cost of managing a special tariff for charging electric vehicles would not be high, as smart meters easily incorporate time discrimination. The market-based option, when there is greater liquidity, should provide more optimised value due to competition. Therefore, the illiquid version with bilateral agreements can be taken as a benchmark as an upper limit.

Considering the days when the MV network is most loaded and the possible increase in consumption generated by the charging points, to avoid overloading, it would be necessary to incentivise the shift of the consumption for 300 hours (mostly working days) of more than 3,000 recharging points. This calculation was obtained from the load duration curve of the medium voltage line (Fig. 11). Following the same method as in the previous case, ordering the hours of the year from highest load to lowest load in descending order, the 300 hours in which a solution is necessary are obtained, which are those which in the load duration curve are above the

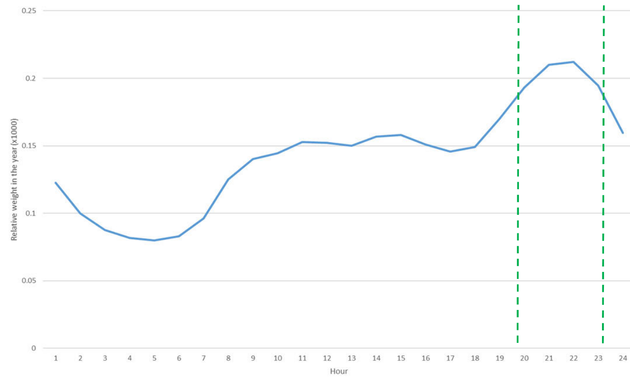

FIGURE 12. **Typical load profile in Spain fitting residential consumption (peak consumption in the evening). Source: REE (Spanish TSO).**

limit. These limitations fit the peak load hours of the typical consumption profile in Spain shown in Fig. 12.

a: FLEXIBILITY SOLUTION COST

Under the same assumptions as in the previous case study, the operating costs related to activation hours considered are: an operational cost of activation (0,15€ per charging point and activation in terms of aggregation and FSP costs); and the operating costs related to the number of fsp are: Registration (0,25h per charging point), planning costs considered as Cost Benefit Analysis (10h) and Definition of scenarios (10h). All costs are based on person-hours. And operational expenses for managing schedules (1€ per charger and year); and some investments in communications (100€) and data acquisition (10€ per charger and year) are considered. All these values are based on the experience of the pilots conducted by i-DE (Spanish DSO) CoordiNet [4] and OneNet [6].

The obtained costs are:

$$\boldsymbol{Cost_2^{Act}} = \mathbf{3000 \times 0.05} = 150€$$

$$\boldsymbol{Cost_2^{fsp}} = 3000 \times \left(0.25h \times \frac{40000€}{1760h} + 1e + 10€\right) + 100€$$
$$= 50,145€$$

From the UDC curve, the constants A and B are calculated:

$$\boldsymbol{Cost'^{flex}_n} = \boldsymbol{e}\string^\mathbf{((160.17 - \mathit{P})/(9.534))} \times \boldsymbol{Cost_1^{Act}} + \boldsymbol{Cost_1^{fsp}}$$
$$= \boldsymbol{e}^{\frac{\mathbf{160.17-\mathit{P}}}{\mathbf{9.534}}} \times \mathbf{150}\boldsymbol{C}\ 50145 = \mathbf{96,595€}$$

4) COMPARISON AND SENSITIVITY ANALYSIS

The variation of the level of congestion over the years and compare it with the lifetime of the asset provide a more robust results in this case. However, the annualised value of the investment and the scenario with 3000 charging points are used to simplify the calculation.

a: COMPARISON

The assessment of the case is shown in Table 6.

In this case, both solutions' costs are tight. The largest driver of the aggregation cost is the activation cost transferred to the end-customer as an incentive. However, the price

TABLE 6. Costs assessment for Congestions in MV network due to electric vehicle charging.

Business As Usual: Reinforcement			Alternative with a flexibility service from EV charging	
Investment cost	Years	Annual cost	Hours of activation	Annual Cost
1,656,700€	40	96,549.43€	310	96,595€

received by each of the users of the 3000 charging points amounts to 15€ per year, which is not a very attractive figure for the effort required by the customer for a whole year. If the time of activation also increases, it makes the flexible solution costlier.

b: SENSITIVITY ANALYSIS

In this case, the cost of the BAU solution is influenced by the distances of the new lines. Again, half the number of line kilometres would lower the BAU cost almost proportionally.

The case study is almost at the break-even point itself. In addition to the factors that influence the cost of reinforcement, such as the distance to existing assets, the unit cost of reinforcements or the capacity of the current network, other parameters influence these needs. For example, the hours of activations or resources involved in congestion management. However, the cost per activation, even if doubled or tripled, would still be of little incentive value to the end user. Not even with significant economies of scale bringing the cost down would make the flexible option competitive enough to provide value to the end consumers. In the case studied, eliminating the aggregator's operating costs, the maximum price to be delivered to the customer would be 0.26€, which appears to be insufficient.

C. CASE STUDY 3: RELIABILITY. MAINTENANCE OF A HIGH-VOLTAGE LINE USING DG FLEXIBILITY

1) GRID DESCRIPTION AND IDENTIFICATION OF THE NETWORK NEED

As discussed above, the maintenance of a HV line is a traditional driver, but the case could be also representative of resiliency considerations. Besides, this case study shows that flexibility may also support in case of conventional needs/drivers. Fig. 13. shows the diagram explaining the case study. That is a request for work on a 132kV double circuit for three hours. According to [57], the average duration of programmed outages would be around one hour, but it includes many shorter MV works. A 132kV work has more demanding security requirements that require more time, so the three hours requested for this case are considered representative.

Two 132kV lines running in a double circuit, sharing poles, must be interrupted for some time due to scheduled maintenance works. These two lines feed a transformer substation located in area E in Fig. 13, which in turn feeds several MV feeders and a 66kV line. The only alternative to maintain the service to the MV and LV customers affected by the maintenance works is through the supply from the 66kV line, which also feeds the 20kV bus, but the total power required is 60MW and the 66kV line does not support that load. Moreover, the line capacity cannot be dedicated exclusively to this need, as it feeds other substations. As shown Fig. 13, a generator is connected to one of 132kV lines and is capable of supplying 50MW, fully relieving the needs of area E.

2) BUSINESS AS USUAL SOLUTION

In this case, following the methodology in section B, the TC will not be considered. It is the cost of the remedial actions that must be assessed. As shown in Fig. 14, when the two 132kV lines to the E substation are interrupted, the entire 132kV grid in the area is de-energised. Under normal network operation, it is not possible for the DSO to maintain an island on the 132kV network and manage the balancing, even locally. It is therefore necessary to limit the power in area E to meet the capacity of the 66kV network resulting in 30MW demand to be curtailed.

Regarding the BAU solution for short-term needs. No reinforcement is considered. The TC could be adapted depending on the emergency. But in this case study, excess power is too much to bear even for a short time. Therefore, it is necessary to consider remedial actions costs.

The result, in this case, is the interruption of a large part of the 60MW consumption at substation E, which cannot be fed from the 66kV line. Note that, in this case, since the DSO is addressing an operational need, grid reinforcements are not considered (at least in the short-term). Hence, the costs associated are purely operating costs. Small generators connected in LV grids may be a solution for smaller power requirements to supply some specific loads, but the number of units required may be significant.

a: BAU SOLUTION COST

As mentioned above, the assumption is that works occur during the daytime.

- The total cost of the load shedding, in terms of VoLL is 711,000€: 3h x 30MW x 7,900€/MWh = 711,000€

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

Enabling the generator to maintain the network island operation at 132kV and managing the appropriate quality parameters including voltages within ranges, and the area may not face any supply interruption. The generator must be committed to maintain power for the duration of the work. Given that this is a Combined Heat and Power (CHP) unit expected to be generating during the maintenance work, there is no additional costs of providing such as service. On the contrary, it is an opportunity to generate which was not possible under BAU conditions.

The case of the maintenance works can only be managed with short-term mechanisms, which are related to markets when there is liquidity or to bilateral contracts when there is not enough liquidity in the market, following the framework presented in [27]. As for the costs of a maintenance operation

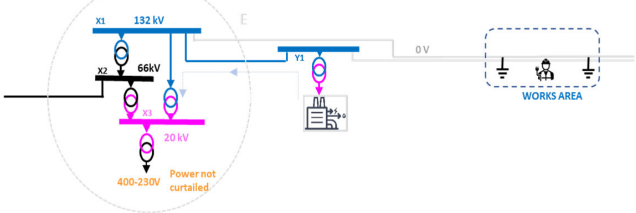

FIGURE 13. Single-line diagram of a grid for maintenance of a high-voltage line of i-DE network. Source: i-DE (Spanish DSO).

FIGURE 14. Single-line diagram during works in BAU situation. Source: i-DE (Spanish DSO).

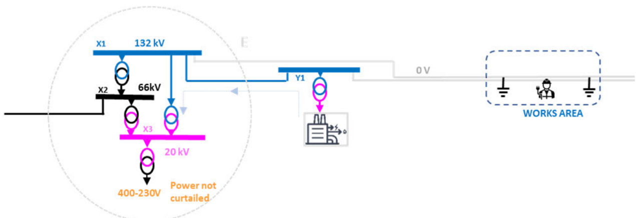

FIGURE 15. Single-line diagram during works with flexibility solution DSO acting as system operator. Source: i-DE (Spanish DSO).

as proposed, the recurrent cost of making a short-term market available would again depend on the liquidity of the market, leaving room for bilateral agreements in the absence of liquidity.

The cost of energy injection is assumed to be zero. If the network is missing, the production process does not stop as the thermal process keeps working and self-generating in island mode. As it is CHP unit, the thermal demand is assumed not flexible, therefore, the generation has to be available as far as the thermal process works. If thermal process were flexible, the CHP would request remuneration to keep supporting the grid and, therefore, the DSO would have to pay for the service availability to maintain grid reliability.

The presented need is occasional, and it is difficult to estimate future needs. However, given that the review periods of the installations are triennial [58], it is expected to have the same need at least once every three years.

a: FLEXIBILITY SOLUTION COST

In this case, activations do not depend on a UDC curve but on a specific need. To calculate the cost in this case the components considered are: Monitoring (hours of activation +0,5), Prequalification (2h/fsp), Cost Benefit Analysis (10h/fsp), Registration (2h/fsp), Billing (1,5h/fsp) and Needs Calculation (1h/fsp). It is not necessary to consider Planning costs as they are short-term needs nor market costs, as this

TABLE 7. Costs assessment for maintenance works.

Business As Usual: outage			Alternative with a flexibility service	
Energy	VoLL	Intervention cost	Hours of activation	Annual Cost
90 MWh	7,900€/MWh	711,000€	3	443.18€

need can only be solved by one FSP. With equation (14):

$$\begin{aligned} \boldsymbol{Cost_3^{flex}} &= \left(\boldsymbol{3h \times Cost_i^{Act}}\right) + \left(\boldsymbol{Cost_i^{fsp}}\right) \\ &= \left(3h \times \frac{40000€}{1760h}\right) \\ &\quad + \left((2+10+2+1.5+1)\,h \times \frac{40000€}{1760h}\right) = 443€ \end{aligned}$$

4) COMPARISON AND SENSITIVITY ANALYSIS

Numerous alternatives through the MV network can surely help in case of an outage, in addition to the power that the 66kV network involved can provide. In this case, the network is sufficiently interconnected so that it is considered that only half of the 60MW load is going to suffer an actual outage. The maintenance works could be expected to last 3 hours. This duration should have considered other efficient solutions such as shifting the work schedule to night-time to minimize the impact on end-users, but this is not always possible because of the labour legislation (e.g., European Directive [59]).

a: COMPARISON

Only the cost of the flexibility mechanism is considered. The assessment of the case is shown in Table 7.

In the short term the difference is obvious, but many sunk costs have been considered in this case. Uncertainty in short-term needs makes it difficult to generate costly investments at the local level. The sunk costs of operation, planning and market needs are for the system and not for the specific local situation. But the monitoring or resource management costs of the aggregator or FSP can only be considered as sunk costs if they are necessary for the regular operation of the network.

b: SENSITIVITY ANALYSIS

The difference costs above shows the amount the DSO could devote to the sunk costs. If the sunk cost figures do not break down individually, they should be calculated collectively considering that situations like this occur on the network on a daily basis.

On the other hand, there are also the sunk costs of the aggregator or FSP. If the interface with the market and the exchange of data is simple and cheap, and the operational costs of activation are not very significant, liquidity in these short-term markets would also improve.

Sunk costs aside, the cost of non-delivered energy or the value of lost load (VoLL) is always high. Therefore, considering the actual cost of the flexible option that requires only

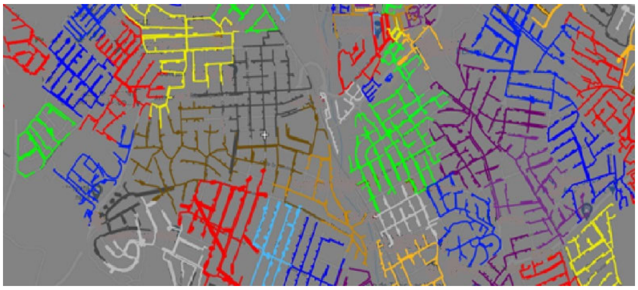

FIGURE 16. LV grid in the area of a single-family house. Each colour represents a different feeder. Source: i-DE (Spanish DSO).

a few DSO operator hours, there is no further analysis to be made. It seems the benefits from the flexibility service are enough to support this use case. Other variables such as the cost of energy are not significant. The big change is to enable the DSO to manage DG to avoid an outage.

D. CASE STUDY 4: MASSIVE DG CONNECTION LV. CONGESTION ON LV NETWORK AS A RESULT OF NEW ROOFTOP PV GENERATION

This case addresses the impact that the massive implementation of solar generation in the LV network of an area of single-family houses. Practically all of the consumption in the presented area is from single-family households with rooftop solar generation. The distribution network is dimensioned to evacuate the power that households have contracted, affected by a simultaneity factor which is not suitable for photovoltaic (PV) units. Therefore, the installation of PV generators could exceed the limits of the feeders or the substations and would require new reinforcements in the network. Generation is not expected to exceed the power of the individual evacuation line, which corresponds to the contracted power (i.e. purchased by the consumer) and is not affected by any simultaneity factor. The maximum consumption and maximum generation happen at different times of the day.

1) GRID DESCRIPTION AND IDENTIFICATION OF THE NETWORK NEED

In the considered network, selected choosing homogeneity in the load behavior and network design, there are 10 secondary substations in total with a very similar load profile, which have an average of 100 customers each. An aggregated load curve is used. The power of these substations is 400kVA and each of them has 6 LV feeders. Feeder length varies between 200m and 800m. It is assumed that each feeder admits a power of 200kW (150mm2 Al 400/220V) and that the average contracted power[2] is 5kW.

Half of the households have solar panels installed and are generating at full capacity at a time of low consumption, fitting typical load profiles D and F from [56]. Therefore, there would be a simultaneous generation of 500kW at the secondary substation and would exceed the nominal 400kVA, that according to the expected power factor of the PV units could be assimilated to an active power of 400kW. Any variation may be considered an admissible overload due to the small duration or amplitude. In this case, the LV feeders would not suffer capacity saturation with half of the households with PV units.

The assumptions in this case are related to the PV plants, but the grid considered is realistic.

2) BUSINESS AS USUAL SOLUTION

As in previous cases, no TC was provided in this case, as the power needed largely exceeds the capacity limits. Nevertheless, as admitted by the distribution company of the area and supported by [29], short-lasting overloads are admitted, and it covers any variation produced by the assumed unity power factor hypothesis mentioned above. The reinforcement needs, in this case, would be as follows. Power upgrade in a transformer at all 10 secondary substations. No reinforcements would be necessary at higher voltage levels as the minimum demand curve is higher. Some secondary substations would not need upgrades and others would not be possible because they will be too large. Again, for the sake of simplicity, all upgrades are considered to be done evenly throughout the grid.

The same effect is expected in the rest of the adjacent areas, therefore reinforcements in the transformation capacity in the primary substation are needed in the same proportion. Given that a transformer in an urban area is designed to feed several different feeders, for the power calculated, 10% of the cost of a complete transformer is estimated. Even transformers are non-divisible, they are highly interconnected in urban networks, so it is assumed that 10% of the transformers need upgrading.

a: BAU SOLUTION COST

The Spanish catalogue [43] used does not include the option of upgrading the transformer. To arrive at a good approximation in the calculation, the cost of replacing a 630kVA transformer will be obtained by subtracting the cost of installing a (15kVA) substation, that is basically the room building, from the cost of installing a 630kVA substation, that is the room building and the transformer. This removes the costs of the substation, leaving the costs related to the power of the machine. The residual value of the decommissioned machine is not considered, but the decommissioning itself has a cost. Then, the power-related cost of installing a 630kVA transformer is then obtained.

- Power upgrade in the transformers at all 10 secondary substations: 141,090€, including:

- Cost of the secondary substation with 1 × 15kVA machine (code TI-22W in [42]): 23,947€.
- Cost of the secondary substation with 1 630kVA machine (code TI-39W in [42]): 38,056€.
- The estimated cost of installing the 630kVA machine in an existing structure: 14,109€.

[2]Contracted power: maximum power limitation to each customer according to contracting terms.

The lifetime of this investment is 40 years [43] and annualising the cost with a WACC of 5% gives an annual cost of 8,222.47€.

3) ALTERNATIVE SOLUTION WITH A FLEXIBILITY SERVICE

Again, following the framework in [27], the case of LV congestions for solar generation is not very different from the case of MV in terms of the costs of the flexibility mechanism. The market liquidity or the generalisation factor for considering dynamic tariffs are also relevant here. The difference is that in this case the sum of consumption and generation must be considered for the demand forecast.

Solar generation reaches the maximum power during the central hours of the day, with an estimated 80% of the transformers' evacuation capacity being exceeded during the four central hours. This overload situation does not occur on non-working days because domestic consumption increases during these central hours. They would fit typical load profiles D and F from [56] corresponding to the Spanish case shown in Fig. 12. So, the need is to reduce power by 20% (100kW) for 4 hours per day on 200 days a year.

a: FLEXIBILITY SOLUTION COST

The annual operating costs considered are related to registration (0,25h per PV unit), cost benefit analysis (10h) and definition of scenarios (10h), also investments in communications (100€) and data acquisition (10€ per household and year) are considered. Regarding the activation costs, it will depend on the opportunity cost for the generation. A price of 0.0275€/kWh was considered for solar PV as in [53]. With all this:

$$
\begin{aligned}
Cost_4^{Act} &= \mathbf{0.0275}€/\text{kWh} \times 1000\text{kW} \times 200 \times 4\text{h} \\
&= 27.5€ \\
Cost_4^{fsp} &= \left((500 \times 0.25 + 20)\, h \times \frac{40000€}{1760h} \right) \\
&\quad + 500 \times 10 + 100 = 8,395.45€
\end{aligned}
$$

From the UDC curve, the constants A and B are calculated:

$$
\begin{aligned}
Cost_4^{flex} &= e^{\frac{865.11-P}{9.737}} \times Cost_4^{Act} + Cost_4^{fsp} = e^{\frac{865.11-P}{9.737}} \\
&\quad \times 27.5 + 8395.45 = 30,445.07€
\end{aligned}
$$

4) COMPARISON AND SENSITIVITY ANALYSIS

In this case, a residential area of 1,000 customers fed by 10 secondary substations is considered. The existence of a well-dimensioned network is also assumed. Obviously, the casuistry is enormous and although it cannot be extrapolated to all situations, the results provide an order of magnitude of the costs.

a: COMPARISON

The assessment of the case is shown in Table 8.

Similar to case 2, the flexible solution can be considered cheaper when the time of activation is small, and not for a sustained situation where activations have a daily occurrence.

TABLE 8. Costs assessment for congestions in LV.

Business As Usual: Reinforcement			Alternative with a flexibility service	
Investment cost	Years	Annual cost	Hours of activation	Annual Cost
141,090€	40	8,222.47€	800	30,445.07€

TABLE 9. Cost results for the different case studies.

Case study	Annual cost BAU	Annual cost with a flexibility service	Is there an evident benefit of the flexibility service?
1. New flexible connection	369,075.59€	28.722,56€	Yes
2. Congestion on MV network	96,549.43€	96,595€	No
3. Maintenance works	711,000€	443,18€	Yes
4. Congestion on LV network	8,222.47€	30,445.07€	No

This suggests that the solution would be useful for postponing investments rather than replacing them.

b: SENSITIVITY ANALYSIS

Here again, the activation costs are important. Smart meters could play a role in limiting these costs, as well as the inverter software applications of the PV panels themselves. The energy cost and the hours of activations are also relevant. In the BAU case, it is not so much the distances that matter but the grid design capacity itself. A multi-year plan is likely to be necessary to cater for the necessary upgrade for all these power increases and to coexist with flexible solutions as long as the time of activation is small.

The price of 0.0275€/kWh considered for solar PV generation in [53] could vary and affect the result. But even if it was reduced to a third, the overall conclusions would not change.

In the long-term, the alternative with a flexibility service does not seem economically viable. As the break-even point is reached with an energy price close to zero. So, it seems that it may be an option just to delay investment, as long as the time of activation is small.

E. DISCUSSION: COSTS COMPARISON: OF BAU VS FLEX SOLUTIONS

A summary of the costs of flexibility and business as usual solutions are shown in Table 9.

The results show that flexibility mechanisms can be particularly attractive solutions for new flexible connections (case 1) and to ensure grid security during planned maintenance works (case 3). Moreover, flexible solutions can

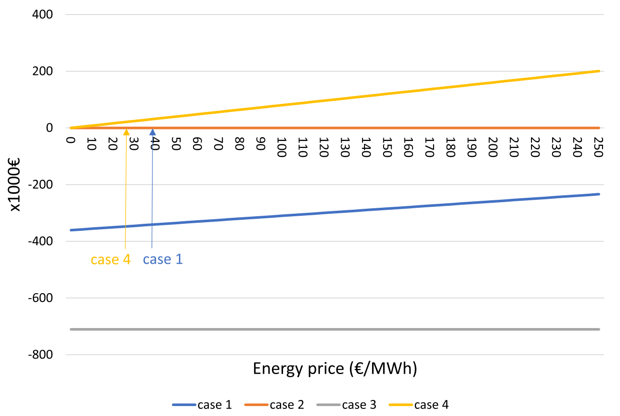

FIGURE 17. Net value (Flexibility - BAU) variation with the energy price. Source: own elaboration.

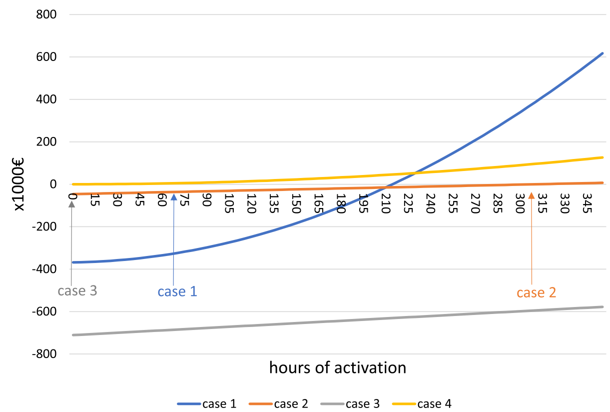

FIGURE 18. Net value (Flexibility - BAU) variation of the flexibility cost with the hours of activations. Source: own elaboration.

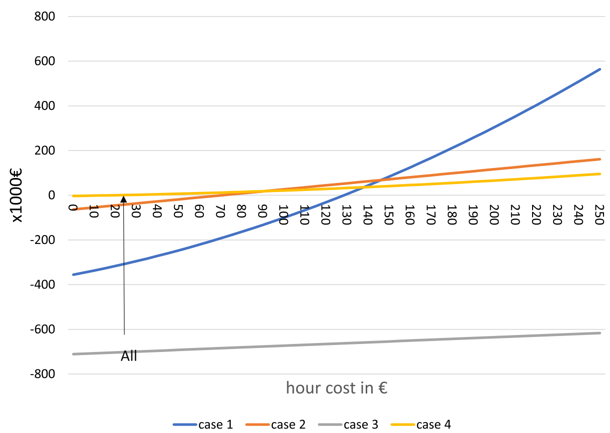

FIGURE 19. Net value (Flexibility - BAU) variation of the flexibility cost with the operational cost of the DSO. Source own elaboration.

be useful while the reinforcement is being built as it may temporarily be the only solution (cases 2 and 4). The competitiveness of the flexibility-based solution mainly in case 1 depend on the time of activation. This means that, in the case of few activations, there is a lot of margin compared to the traditional solution.

Fig. 17 shows the net value of flexibility (benefits minus costs) and its variation with respect to the energy price.

It follows that the break-even point of case 1 is reached with a high value, which makes it cost-effective, and that of case 4 with a value close to zero, which makes flexibility hardly viable in this case. This is consistent with the previous conclusions. Cases 2 and 3 being insensitive to the price of energy.

Regarding the variation with respect to the hours of activations, the conclusions are different. Fig. 18 represents this sensitivity. Case 1 turns out to be quite sensitive with respect to the hours of activations, finding a break-even point close to 210 hours. Which is also logical, because flexible connections are designed for cases in which the peak of need is reached in a few hours a year.

For the rest of the cases, a greater insensitivity is observed, although a number of hours greater than 80 hours also makes cases 2 and 4 unfeasible. Case 3 is uniform by increasing the number of hours, but it is a different case, since what is valued in this case is the duration of the scheduled outage and it is compared to interrupted supply. It is unreasonable to consider hundreds of hours in this case.

Finally, it is necessary to observe the variation with respect to the labour cost of the DSO in hours showed in Fig. 19. This will depend on the efficiency of the process and the digitalization and observability of the network, which will allow the process to be automated and less costly without losing reliability. In this case, the conclusions are similar to those of the variation with the hours of activations. While it is true that this cost is not likely to grow with the maturity of the solution, but to decrease. Therefore, if the operational labour cost decreases as expected cases 1, 2 and 3 will continue to be clearly viable. The viability for case 4 will depend on other variables such as the energy price.

It is also important to consider reinforcement costs (BAU cost) for new flexible connections as well as for congestion management. In the case of flexible connections the margin is very wide due to the low cost of activation. But in the case of congestion, the BAU solution must be very expensive to for the flexible solution to break-even. This variable will move up or down the curves in figures Fig.17, Fig. 18, and Fig. 19.

Throughout the study, the importance of taking into account all types of costs and not neglecting any that may be relevant to the viability of the solution is demonstrated.

There are also sunk costs that need to be considered when studying the whole solution, but not to assess a specific flexibility application within a limited network area. For an FSP, the uncertainty of how many times a service will be required is also a barrier to investment. The cost of this uncertainty is not handled in the presented studies. The necessary information exchange and the transparency of the agents involved can alleviate this uncertainty. The grid congestion maps published by DSOs in Europe are an example of this (e.g. [60], [61])

Based on the flexibility services considered, it can be concluded that flexibility services are highly case-dependent and do not always outperform the traditional alternatives.

Flexible connections (i.e., agreements that give the DSO the right to limit power injections or withdrawals during a specified time) are a paradigm shift for the DSO and accelerate the energy transition by allowing faster and cheaper connections. For example, for avoiding N-1 reinforcements that are sporadically used. Flexibility services and the possibility for the DSO to use DG to supply local demand in case of network failures or maintenance in cases where the grid has a weak connection with the rest of the grid are tremendously useful. Both solutions have an obvious benefit, as the alternative is to wait until reinforcements are made.

In the case of seeking to avoid grid reinforcement, the benefit is not so obvious, and it would be necessary to create a context in which the motivation of grid users and the reliability of service delivery compensate for the reliability and security benefits of grid reinforcement. For the case of congestion caused by PV generation, there is very little room to compensate for the operational costs of the flexible solution or the customer incentive. Only for zero energy prices scenario it could be a competitive solution. MV grid reinforcements can also be very competitive in urban environments and difficult to be replaced by flexibility services. Subsequently, further studies would be necessary to determine whether flexibility can compensate for the effect of the new drivers for grid reinforcements or whether BAU solutions still prevail as the most efficient solution.

V. CONCLUSION

This paper proposes a general method to evaluate the cost of flexibility for any type of need and that can be applied to any case study.

One of the main findings is that the value of flexibility depends on the type of need and associated characteristics such as the number of activations, the price of energy or the cost to the DSO. Therefore it is necessary to address a wide range of parameters before taken a decision.

The difficulties to obtain real data to estimate costs and the difficulties to obtain reliable data, not only for the access to the information but also for the immaturity of the process regarding to flexibility solutions for DSOs are the limitations of this research.

This paper performs a necessary comprehensive analysis of the real costs of flexible solutions to compare them with traditional solutions and avoid neglecting decisive parameters that may determine the effectiveness of the flexible solution against business-as-usual solutions not considered in previous papers. A descriptive methodology to evaluate flexibility costs is proposed to make an exhaustive description of the flexibility costs, both OPEX and CAPEX of each of the stakeholders involved, providing formulas that simplify their study and a method of comparison depending on the needs' type. Then, an analysis of four representative and realistic case studies in Spain, accurately selected starting from representative drivers, is conducted to compare business as usual solutions with flexibility alternatives. One case refers to a flexible connection of new distributed generation, the second considers congestion management in an urban MV feeder managing EV charge demand, the third case relates to programmed outages due to maintenance works, and the last one considers to congestion management in LV grids managing PV generation. Various network situations are selected, at different voltage levels; with diverse resources, with different types of generation and demand; and related to the new drivers, distributed generation, new flexible connections, and electric vehicle charging points. BAU solutions are proposed and compared with the corresponding flexible solution. Then, the value that flexibility can bring to the future challenges facing the distribution networks are assessed. Concluding that flexibility services are highly case-dependent and they do not always outperform the traditional alternatives.

Following the analysis carried out, certain parameters can vary greatly and induce a sensitivity analysis, such as the hours of activations of a flexibility solution, the implementation and operating costs for the DSO, the value of load lost or the remedial actions, the cost of reinforcements, or the cost of energy whose magnitudes determine the true value of flexibility. The values taken in this paper try to be realistic and reflect situations that are as real as possible considering the expected penetration of distributed energy resources.

Overall, it can be concluded that the paradigm shift of flexibility services may be especially useful from an operational perspective, as it allows more optimal extraction of the potential of the network in the short term. And it is also useful to accelerate the integration of distributed renewable generation by allowing flexible connections. For the long-term use of flexibility, it is necessary to thoroughly assess each need to establish whether flexibility services can compete with BAU solutions considering their reliability, duration and the number of customers involved. But given that the needs of the network are progressing over time, flexible tools are valid to postpone investments for a few years as long as the number of hours of activations required is limited.

A wider range of use cases studied considering all costs faced by the different flexibility providers with the same methodology would definitely help to take informed decisions. Alternative methods to assess flexibility potential could provide more accurate estimated costs when the quantity and quality of data provided is enough.

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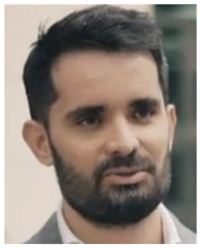
FERNANDO-DAVID MARTÍN-UTRILLA received the degree in law and the degree in business sciences from Universidad de Salamanca, the degree in marketing from Universidad Miguel Hernández, Elche, and the Master in Energy Business Management (M.B.A.) degree from Universidad Nebrija, Madrid. He is currently pursuing the Ph.D. degree in planning and regulation with the DSO Department. He is also with i-DE (Iberdrola), Valencia. He is also a Industrial Engineer with Universidad Politécnica Valencia. He joined Iberdrola, in 1999, and during 20 years, he has had different operational responsibilities in Salamanca, Alicante and Murcia in Spain, and Recife in Brazil. The last few years, he has been leading i-DE's DSO role in Spain being involved in strategic projects, such as CoordiNet, OneNet, and Flexener. He is coordinating the BeFlexible Project launched, in September 2022.



JOSÉ PABLO CHAVES-ÁVILA received the bachelor's degree in economics from the University of Costa Rica, Costa Rica, in 2008, the master's degree in electric power industry from the ICAI School of Engineering, Comillas Pontifical University, the Erasmus Mundus master's degree in economics and management of network industries, the master's degree in digital economics and network industries from Paris Sud-11, Paris, France, and the Erasmus Mundus Joint Ph.D. degree in sustainable energy technologies and strategies from the Delft University of Technology, The Netherlands, in 2014, under the joint program with Comillas Pontifical University and the Royal Institute of Technology (KTH), Sweden. He is currently a Research Professor with the Institute for Research in Technology (IIT), ICAI School of Engineering, Comillas Pontifical University. In August 2020, he was selected as a member of the Expert list of the Regional Commission of the Electrical Interconnection for Central American (CRIE) and he was appointed as a member of the ACER Expert Group on Demand Side Flexibility for EU Agency for the Cooperation of Energy Regulators (ACER), in September 2021. He has been a Visiting Scholar with the European University Institute, Italy; the Lawrence Berkeley National Laboratory, USA; and the Massachusetts Institute of Technology (MIT), USA. Since September 2016, he has been the Lead of the ISGAN Virtual Learning of the International Smart Grid Action Network.

RAFAEL COSSENT received the Industrial Engineering degree from the ICAI School of Engineering, Comillas Pontifical University, and the Ph.D. degree in electrical engineering from Comillas Pontifical University. He is currently a Researcher with the Institute for Research in Technology (IIT), ICAI School of Engineering, Comillas Pontifical University, where he acted as a Coordinator of the Research Unit on Smart and Sustainable Grids, between 2016 and 2021. Additionally, he is also the Co-Director of the Chair for Hydrogen Studies and he has previously acted as a Coordinator of the BP Chair in Energy and Sustainability. Besides his research activities, he teaches on the regulation of network activities in the power sector. Throughout his academic career, he has participated in over 50 research and consultancy projects dealing with power sector economics and regulation, integration of renewable and distributed generation, electric mobility, smart grids, and decarbonization and energy transition. He has published over 50 papers in national and international journals and conference proceedings on these topics. He has been a Visiting Researcher with INESC, Porto, Portugal, and Heriot-Watt University, Edimburgh, Scotland. He has contributed to the on-line education program of the Florence School of Regulation.