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Deliverable D4.1
Distribution Network Planning Strategies considering V2X Flexibilities

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Executive Summary

The traditional optimization problem approach of distribution grid planning aiming to minimize energy losses is no longer sufficient to guarantee backup capacity in the face of increasing electrification of transport and heating sectors and the penetration of Distributed Energy Resources (DER). The new paradigm for modern grids relies on two key principles: chronological modelling of loads to determine capacity needs, and flexibility, which involves adjusting to changes using a combination of Demand Response (DR) services, energy storage, and DER. In this deliverable, the focus is on the use of Electric Vehicles (EVs) as a source of flexibility: EV owners can become capacity enablers by providing charging load or power injection capability to mitigate network congestions. This flexibility is compensated for a price that is analogous to the investment in infrastructure reinforcement for the same capacity. This approach reduces the risk of stranded assets in face of uncertain load growth evolution.

To evaluate such flexibility and incorporate it into planning tools, it's necessary to develop an EV charging flexibility model that can be promptly characterized by the planner based on very few information about its future use, while still being capable of representing the main features, limitations, and costs of EV flexibility. The developed model proposed in this deliverable enables the estimation of the main flexibility features of a given resource based on four parameters: occupancy and charging rates of the flexibility resource, and the number and power capacity of the EV chargers. In this model, EV charging load shift and Vehicle-to-Grid (V2G) have a similar effect on the aggregate load state, but V2G allows for choosing when to discharge, while Vehicle-on-Grid (V1G) requires shifting within the planned charging period. Hence, the primary value of V2G in congestion management for peak shaving services is its ability to create new opportunities for V1G to shift, which can be important if there are not enough charging sessions available.

The EV flexibility charging model can be then integrated into a planning approach that assumes a high penetration of EVs and the creation of EV aggregators (which faces many challenges and barriers as of today). This methodology searches for grid solutions that trade off investment costs against flexibility resource costs and other operational costs, like those incurred in energy losses. In this way, the impact of grid structural limitations is mitigated by flexible resources if the load reduction that is necessary to eliminate overloads can be undertaken at a cost lower than the Energy Not Supplied (ENS).

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Acronym

DR	Demand Response
DER	Distributed Energy Resources
DSO	Distribution System Operator
ENS	Energy Not Supplied
EV	Electric Vehicle
RES	Renewable Energy Sources
TSO	Transmission System Operator
UK	United Kingdom
V1G	Vehicle-on-Grid (Unidirectional Charging)
V2G	Vehicle-to-Grid (Bidirectional Charging)
V2X	Vehicle-to-Everything

Nomenclature

T	Time period
N	Cardinality of the population of EV chargers
L	Aggregate (normalised) load demand of the population
v	Shifting velocity
d_c	Charging density
C	Charging rate
d_o	Occupancy density
O	Occupancy rate
w	Number of discharging decisions
λ	Failure rate of the line or cable
m	Branch
E	ENS
R	Reliability cost function
S	Energy losses cost function
I	Capital cost function
D	Demand for flexibility resources
F	Flexibility cost function
π	Clearing price for the procured flexibility

1 Introduction

1.1 Scope and Objectives

Modern distribution grids are in a path sometimes referred to as “3D’s”: decarbonization, decentralization, and digitalisation. These trends manifest in the growing number of devices installed at homes and buildings, like storage and photovoltaics, the deployment of smart meters and local energy management systems, and, of course, the electrification of otherwise fossil-fuel based resources, such as heating and vehicles. These novelties, alongside dramatically changing the grids’ behaviour, open new possibilities when it comes to leveraging the full potential of the installed infrastructure, while keeping it safe and reliable. The planning of these modern grids must then adopt new approaches and models to keep up with these changes.

When it comes to planning grids with a high penetration of EV chargers, flexibility is key, and the models that quantify the potential arising from EV charging loads must be compatible with distribution system optimization and the algorithms upon which grid planning tools are based. They must be simple enough to not overburden the decision-making, but at the same time capable of representing the main features of the loads’ flexibility, their limitations, and corresponding costs as dependent on such features.

This deliverable describes in depth a model for EV charging flexibility and how to correctly deploy it in distribution grids’ planning. It also discusses the relevance of smart charging and V2G in this context and identify the flexibility contracts and what are their key success factors and insights.

1.2 Structure

This document structure follows a straightforward rationale: Section 2 starts by discussing the inadequacy of traditional planning strategies to comply with modern grid features, introduces the concept of flexibility (illustrated by real-world EV-charging data), and identify flexibility contracts and how it can be a cost-effective solution. In Section 3, a detailed model of EV charging flexibility is presented: first, in a simplified form that, although not realistic, is practical to understand the approach; then, in its more complete form, closer to a realistic utilization of EV chargers and supporting V2G. Section 4 more broadly discusses how to introduce flexibility into distribution grid planning and consider it in the infrastructure investment decisions.

1.3 Relationship with other deliverables

Work Package 1 (*Millions of EVs Scenarios, Business Models and Technologies*) aims to define road e-mobility evolution scenarios, with its Deliverable 1.1 [1] introducing a forecast for transport electrification in Denmark, Greece, Slovenia, and Portugal, considering the time horizons of 2030, 2040, and 2050. The present deliverable then introduces a proper approach and the necessary modelling tools for planning the distribution grids that will support this evolution in a smart way, that is, leveraging EV charging flexibility to optimize investments and lower risks. Deliverable 4.2, focused on the scheduling and operation of distribution grids, shall dig into flexibility contracts and their deployment to avoid network congestions in benefit of the EV users. The present deliverable does not directly apply to the demonstration activities.

2 Flexibility Prospects

In the early days of electrification, distribution grid planning consisted of deciding between a few mutually exclusive grid topology options, adapting typified grid designs to the available equipment and the existing topography of the areas to be served. Within the available topologies, grid design and equipment selection tasks could be formulated as optimization problems [2] aiming to minimize energy losses. The result would have been grid designs that guaranteed backup capacity, even when this wasn't explicitly formulated in the study: if there were loads to serve, then there were losses, and if the target was to minimize these, then the result was a high-capacity grid [3]. This paradigm prevailed from the mid-70s to the early 80s. During this time, the optimization problem was formulated considering topology, security constraints, and grid losses costs under fixed-cost, transportation-type, and mixed-integer programming. In the 90s, evolutionary and other advanced heuristics algorithms were developed to deal with uncertainty in load growth and load location.

In the last decade, however, the elements connected to the distribution grids have evolved significantly, with the electrification of transport[1] and heating sectors, and the penetration of DER. These lead to increased peaks at times of low energy generation and lower (distribution) load factors, respectively, driving a paradigm change in distribution grid planning, as the energy losses optimization is no longer sufficient to guarantee backup capacity.

The new paradigm relies on two cornerstones. The first is the chronological modelling of the loads to determine the capacity needs. It banks on the surge of advanced metering infrastructure of the distribution grids, gathering data that allows the synthesis of realistic load profiles and thus the characterization and simulation of congestions in their amplitude, duration, recurrence, and temporality[2] - one of the better-known chronological load characterizations is the so-called "duck chart" [4]. The second is flexibility, defined as the ability to adjust to changes by using a combination of DR services, energy storage, and DER. In the transport electrification context, EV users become capacity enablers, having their vehicles' charging load or power injection capability (*i.e.*, V2G) deployed to mitigate network congestions. This flexibility is compensated for a (contracted) price which is analogous to the investment in infrastructure reinforcement for that same capacity, but with the advantage that, postponing the need for grid expansion investments, the Distribution System Operator (DSO) is also reducing the risk of stranded assets in face of uncertain load growth evolution [5].

2.1 EVs as an opportunity to flexibility

To study the effects of charging clusters of EVs on local electricity grids, EA Technology and the Scottish and Southern Energy Power Distribution developed the "My Electric Avenue" project [6], funded through Ofgem's Low Carbon Networks Fund. This investigation examined several types of low voltage networks in the United Kingdom (UK) and included groups of neighbourhoods that used an EV (Nissan LEAF) for 18 months in order to mimic a future scenario in which many residents choose to drive pure battery EVs or plug-in hybrid EVs. During the project, over 200 EVs were anonymised and monitored, and the participants divided into clusters. During the technical trials, all participants in a cluster were connected to the same low voltage feeder and had their EV charging monitored. Depending on vehicle

[1] A detailed analysis of different EVs evolution scenarios has been published in Deliverable 1.1 of EV4EU.

[2] As line ratings are dynamic, acknowledging the period in which a congestion occurs helps to determine its severity.

usage and network usage, the charging rate could have been reduced. In contrast, another group of social trial participants were located throughout the UK and were not subjected to any curtailment of their EV charging.

From the data made available (EVs monitored from April 2014 to November 2015), two scenarios of interest are analysed: Chiswick and Slough, two neighbourhoods in the great London area. Chiswick is a typical residential area and Slough is a mixed commercial and residential area. The Chiswick trial encompassed charging curtailment in peak hours, while Slough did not have any charging power adjustment.

Figure 1 represents the average occupancy, charging rate, and power output of the Chiswick trial over the monitoring period. The typical higher concentration of charging sessions during evenings can be observed, and a power peak occurs between 21:00 and 23:00. This common charging pattern is characteristic of residential areas. Moreover, the charging power adjustment can be evidenced by a smooth average power output from the feeder.

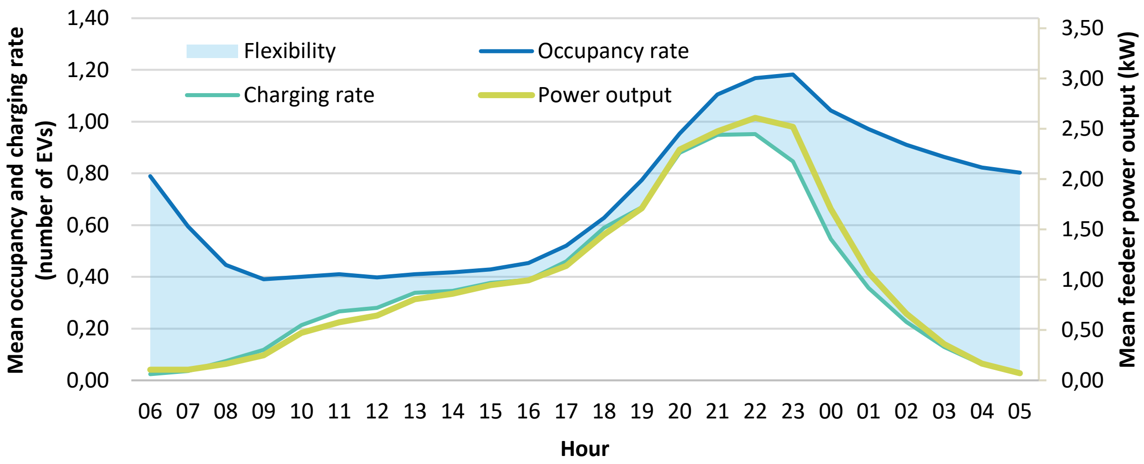


Figure 1 - Average occupancy, charging rate, and feeder power output for the Chiswick trial.

The larger the difference between the mean occupancy and charging rate, the larger the opportunity for flexibility, available via load shifting and V2G. From 20:00 to 6:00 of the following day, EVs would gradually stop charging but be kept plugged-in until morning before leaving, hence increasing the flexibility potential. During the day, the flexibility is reduced, which highlights user awareness about the duration of the charging session (*i.e.*, users are more attentive to unplugging their vehicles right after charging).

The occupancy and charging rate of the Slough trial feeder depicted in Figure 2 encompasses two distinct behaviours: a typical residential charging behaviour during the evenings, and a morning charging behaviour for commuters who arrive for work. The most notorious peak (no charging curtailment) is around 11:00, the hour of maximum power output for commuters. As in the Chiswick trial, the flexibility starts to gradually increase after 20:00 until 6:00 of the following day, representing the overnight charging sessions of the residents. During the day, the mean occupancy and charging rates increase and decrease with a pattern which is coherent with common behaviour in mixed commercial and residential settings promoting a high charging turnover. A somewhat constant average flexibility is observed during this period.

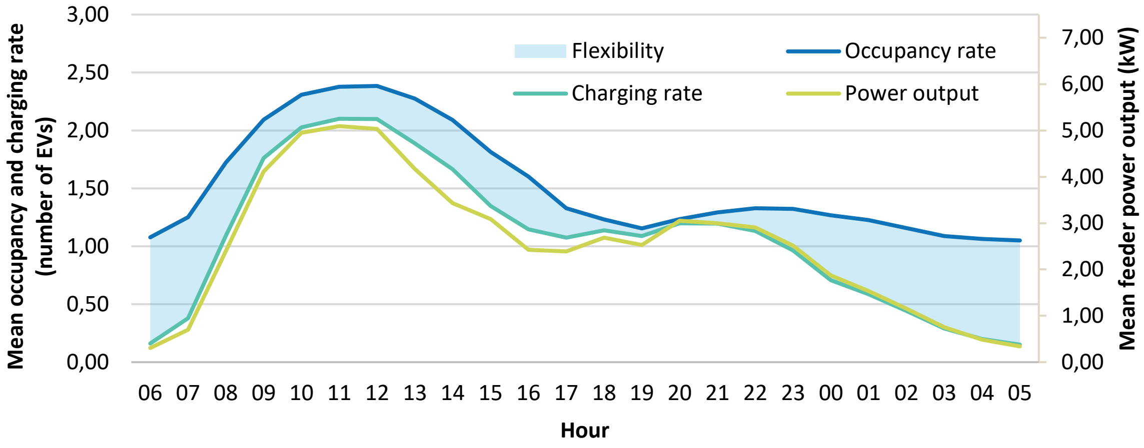


Figure 2 - Average occupancy, charging rate, and feeder power output for the Slough trial.

Figure 3 illustrates the average number of hours per year that each EV in the trial was available to provide flexibility (*i.e.*, the vehicle was plugged in and not charging). In the Chiswick trial, with a charger located in a typical residential area, the most prominent potential is observed during the night period, with a peak at 6:00. In the Slough trial (mixed commercial and residential setting), two cycles can be distinguished. The first one represents a similar overnight charging with an availability peak for flexibility at 6:00 and drops as overnight charging users leave the charging points available for morning users. As the morning users' EVs finish their charging sessions, the second cycle emerges, and the flexibility starts to increase around noon with a peak at 15:00. As an example, assuming that these EVs are capable to provide Vehicle-to-Everything (V2X) services at 3.2 kW during 30 % of the availability periods without compromising the desired daily range, the typical residential and mixed usage charging EVs can provide over 240 kWh and 300 kWh per year, respectively.

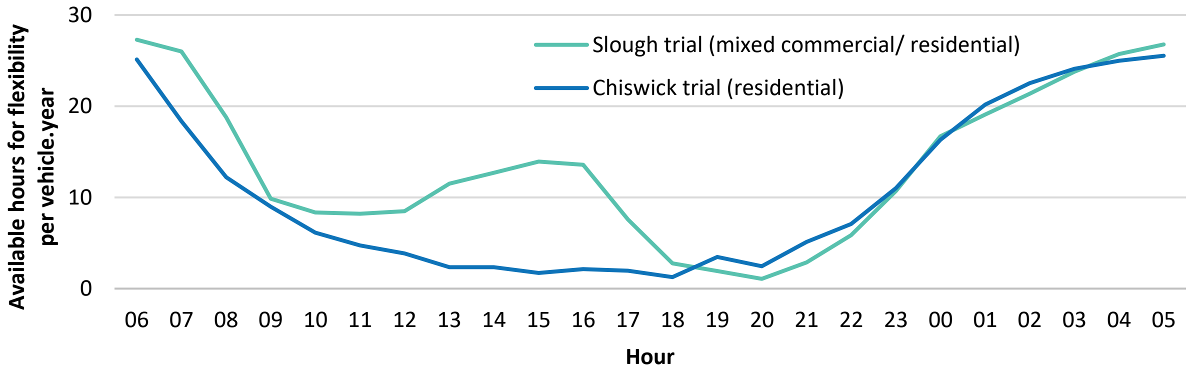


Figure 3 – Flexibility availability for the Chiswick and Slough trials.

2.2 Flexibility contracts

In 2019, the European Parliament and Council of the European Union recognized that attaining the European Union's renewable energy targets would be facilitated if the provision of flexibility were to be rewarded, furthermore emphasizing the consumers' critical role in achieving the flexibility the power system currently needs to adapt to a variable Renewable Energy Sources (RES) and DER paradigm [7].

Flexibility contracts represent a cost-effective solution that can enhance both the efficiency and reliability of the distribution grid, minimizing planning challenges under a scenario of mass smart metering roll-out [8], large-scale penetration of intermittent RES, DER and DR services, growing industrial electrification, and increasing heat pump and electromobility demand [9]. Setting up flexibility contracts supports congestion management at the distribution grid level, which sustains the avoidance of equipment dysfunction or failure due to operation out of rated ranges, thus extending its life expectancy and mitigating its operational cost [9].

A detailed analysis of a Danish 10 kV grid [10] concluded that, on average, the initial congestions to be expected with load increase are solvable through the one-time yearly activation of flexibility resources amounting to 100-200 kW, for 1-4 hours, saving the DSO a total of 7,500€ per year.

Congestions refer to thermal or angle stability overloads of the distribution grid's components, over- and under-voltages, or forced usage occurrences of local fail-over capacity, which, if unattended to, restrict the physical power flow through the network and lead to network performance and power quality deterioration [9].

Conventionally, congestion management is primarily performed via reconfiguring the network or upgrading the rated power of the distribution grid's components. With flexibility contracts, congestion management could be performed by virtue of the active and/or reactive power modulation of flexibility resources [9]. This includes EVs, since their high power, availability, and predictability, as well as their easy and fast-responding charging rate controllability, can be called upon to perform load-shifting or V2G [8].

Voltage control, a specific case of congestion management aimed at settling over- and under-voltage occurrences, is conventionally carried out through the addition of capacitor banks or transformers with automatically adjusting taps, or via generation curtailment. Again, flexibility contracts could enable voltage to be controlled by means of active and/or reactive power modulation of flexibility resources [8].

2.2.1 Procurement coordination mechanisms

Coordination mechanisms enabling the procurement of flexibility contracts may be divided into four main categories, namely:

Market-based framework [9]

Solving local network congestions is currently a monopolistic activity. Nonetheless, according to European law[3], flexibility contracts need to be procured according to a market-based framework, unless resulting in unacceptable levels of economic efficiency (for instance, in terms of liquidity, as well as entry, exit, and transaction costs), market distortion potential, or congestion.

[3] According to Article 32 (1) of Directive (EU) 2019/944: "*Distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.*" [7]

Within a market-based framework, the DSO incentivises the facilitation of (and thus its own access to) flexibility through temporary and usually binding tenders, according to nationally imposed guidelines or requirements. In this context, the DSO may procure flexibility contracts either through bilateral agreements with network users, or via participation in an organised continuous trading or frequent batch auction marketplace where network users bid their flexibility.

On this subject, it is important to mention bilateral agreements are regarded as a natural first step for flexibility contract procurement, followed by the emergence of (probably pay-as-bid) flexibility marketplaces, when sufficient trading volume arises.

In case a market-based framework is unfeasible in consonance with European law, the following coordination mechanisms for the procurement of flexibility contracts may be employed:

<u>Rules-based approach</u> [9]

Within a rules-based approach, the DSO continuously imposes binding technical requirements on new participants for the provision of flexibility, according to the European Union's network codes and guidelines, as well as to national rules. For instance, the DSO may automatise infeed reduction, contingent upon the occurrence of over- and under-voltages.

The rules-based approach has the potential of shifting necessary equipment and settings costs from the DSO to the network users (which are typically given no compensation), while minimising costs to the whole system.

Furthermore, it is worth mentioning that a rules-based approach can be employed as a guaranteed last resort in case other coordination mechanisms for the procurement of flexibility contracts do not deliver as expected.

<u>Connection agreements</u> [9]

In the context of a connection agreement, the DSO reaches continuous or time-limited usually binding agreements with network users for the establishment of non-firm connections, according to national rules (a non-firm connection is a grid connection arrangement where a network user waives its rights to use whatever share of contracted volume it wants, whenever it wants, ultimately modifying its consumption and/or production patterns).

Connection agreements may originate a discriminatory behaviour which is incompatible with European law, since they are not applicable whenever capacity challenges arise out of the modification of the network users' consumption and/or production patterns, hence favouring earlier connected network users.

From an economic perspective, connection agreements potentially reduce the cash flow from network users to the DSO, while impacting the network users' costs, either increasing or decreasing initial or capacity adjustment expenses.

<u>Network tariffs</u> [9]

Within this coordination mechanism, in consonance with national rules, the DSO periodically exposes network users to usually non-binding dynamic tariffs (*i.e.*, tariffs evidencing price differences according to time and location), which are targeted at reducing peak loads. Therefore, flexibility is herein provided not in an explicit but in an implicit manner [9].

It is worth noting that the more continuously tariffs change, the more difficult it will be to effectively allocate and enforce the explicit provision of flexibility, since predicting the behavioural change of network users will be made harder [9].

From an economic perspective, network tariffs are known to reduce the cash flow from network users to the DSO [9].

2.2.2 Preconditions and principles

To guarantee flexibility contracts are procured and set up in consonance with European law, it is imperative to adhere to a wide array of preconditions and underlying principles. On this subject, the following preconditions and principles are especially relevant:

Observability

Locally solving congestions in both meshed and radial networks requires sufficient observability (*i.e.*, the ability to determine the current and forecast the coming grid state, which includes determining where congestions are expected to occur, their cause, size, duration, and timeframe). Naturally, this implies the existence of a complete information ecosystem [9].

Technical prerequisites and operational principles regarding observability, such as data flow direction, exchange method, and delivery frequency need to be determined on a national level, trading off information accuracy and speed with data management costs [9].

Pertaining to data exchange, harmonisation and standardisation are paramount since they leverage stakeholder interoperability and help to avoid proprietary solutions and the lock-in of local resources. Throughout the European power system, standards defined in the Common Information Model are presently those most resorted to [9].

In the context of observability, it is worth mentioning the emerging concept of flexibility resources register. It describes a database that gathers structural technical information on connection points with the potential to provide flexibility, including whether these are qualified to address specific flexibility needs, and shares it with all relevant system operators. Hence, a flexibility resources register leverages DSO visibility of all potential flexibility resources at all relevant voltage levels, apart from enabling value stacking for network users through multi-purpose qualified flexibility resources [9], [11].

Furthermore, it is important to note the emerging traffic light method. It can be utilized to signal congestions in the distribution grid, representing a practical manner to exchange information between the DSO and other stakeholders in all stages of congestion management. The traffic light method is based on three distinct states: green, when no congestion is expected; orange, when a congestion is expected, and the provision of flexibility is required to solve it; red, when the expected congestion is not solved, and the DSO is urged to take immediate corrective actions to ensure the distribution grid's secure operation [11].

Controllability [9]

Herein, controllability is defined as the ability to control own and other assets remotely or manually, in a direct manner through a control centre or indirectly through intermediaries, either individually or in combination with network users or other system operators.

Controllability is crucial for congestion management in a real-time operation scenario at a distribution grid level, given the challenges that the DSO faces to verify and activate intermittent RES, as well as DER and DR services, in collaboration with less experienced and smaller parties when compared with the Transmission System Operator (TSO). In this context, harmonisation and standardisation are essential for system operation, particularly in terms of the prequalification testing process for the provision of flexibility.

Incentives [9]

Equal incentives must be globally ensured within the regulation for the compensation of network expansion costs, classified as capital expenditures, and costs related to congestion management, classified as operational expenditures. In this manner, a level-playing-field is ensured in terms of distribution grid planning, resulting in the choice of the most cost-efficient solution.

Neutrality and unbundling [9]

To ensure the overall most viable and efficient technologies and solutions, it is of the utmost importance that the DSO must act as a neutral facilitator, guaranteeing that all stakeholders are treated equally and non-discriminatorily, which includes ensuring technology-neutrality, as well as transparent exchange and communication of information. Additionally, the DSO is required to be compliant with the unbundling provisions stated in European law[4].

Proportionality [9]

The measures adopted in the procurement and set-up of flexibility contracts are required to be appropriate to the flexibility needs of the DSO and shall not go beyond what is necessary to achieve them.

Free and fair competition [9]

In case a market-based framework is employed for the procurement of flexibility contracts, compliance with European law implies additional preconditions, such as the assurance of free and fair competition.

2.2.3 Components and methods

Moreover, to support the procurement and set-up of flexibility contracts in consonance with European law, the following set of components and methods is proposed [9]:

[4] According to Article 35 (1) of Directive (EU) 2019/944: "*Where the distribution system operator is part of a vertically integrated undertaking, it shall be independent […] from other activities not relating to distribution.*" [7]

Multi-coordination [9]

In accordance with the type of congestion meant to be solved, considering a combination of coordination mechanisms for the procurement of flexibility contracts could prove beneficial. For example, over- and under-voltages may be prevented through the combination of a capacity-based tariff structure and a power-to-voltage rules-based approach.

Aggregation [9]

Interactions within the context of a flexibility contract may be performed directly between the DSO and the network users but are typically more effectively carried out between the DSO and a flexibility operator which aggregates a large group of network users, acting on their behalf.

Financial impartiality [9]

Solving network congestions on a large scale for real-time operation could regularly cause rapid changes in power flow, which escalates the imbalance of balance responsible parties beyond an operationally secure extent, thus severely impacting their financial liability. Therefore, different financial responsibilities and compensation schemes need to be established to avoid implementing flexibility contracts where financial exposure is biased against these parties.

Direct access [9]

Given flexibility contracts are not yet a mature practice, it is initially preferrable for the DSO to access flexibility directly through a control centre, reducing dependencies on intermediaries in crucial stages of operation. In particular, direct controllability is advised during the emergence of bilateral contracts, given the involved operational risk.

Flexibility contract design best practices [9]

First, flexibility contracts need to be standardised on a national or regional level, whilst avoiding the creation of unjustified barriers to flexibility provision. Secondly, flexibility contract requirements need to remain unchanged both during its procurement and set-up.

It is also important to note that, depending on its granularity, network congestion related information can be to the detriment of the power system's flexibility. For instance, if locational information is made available with excessive resolution, it could enable gaming issues. Therefore, flexibility contracts need to be parametrised in a manner which is as broad as possible, to maximize the participation of network users, and as specific as needed, to guarantee the congestion is solved.

Finally, to ensure the maximal possible use of flexibility not only at the distribution grid level, but to the overall power system, flexibility contract procurement procedures need to be communicated with enough time in advance to allow for flexibility bids to adapt to alternative mechanisms, such as balancing.

Flexibility marketplace design best practices

Naturally, a vast plurality of methodologies can be adopted for the design of a marketplace to support flexibility contract procurement. In this regard, a wide array of best practices for flexibility marketplace design is herein introduced.

Firstly, congestion management needs to be split up into different timeframes, specifically, long, short, and operational term, allowing for the network congestion to be solved long before, prior to, during, or aftermarket clearing [9].

Next in order, TSO and DSO operation needs to be entirely independent when solving network congestions, since flexibility resources with high geographical and temporal specificity are required at the distribution grid level and are not reliantly accessed through combined TSO-DSO action [9]. Nevertheless, it is worth mentioning that flexibility resource registers would enable market participation considering both separate and combined TSO-DSO operation [11].

In addition, an independent marketplace for flexibility trading is deemed as a more suitable option for congestion management, in comparison with its partial or full integration within existing marketplaces. This is so because, considering a fully separate marketplace, it is easier to adapt to the needs arising out of distribution grid planning, as well as to determine the marketplace operator's role in the regulated and non-regulated domains [9].

Furthermore, enabling the reservation of flexibility resources and the predetermination of the activation cost helps to secure the availability of flexibility resources in longer terms, thus increasing market power and predictability on the DSO's side [9].

Finally, in the case of EV flexibility, a maximum market settlement period of 5 minutes is proposed, to not impose high inconvenience for the EV users, since the respective EV would become unavailable during this period when providing flexibility [8].

2.2.4 Key procurement parameters

With respect to the parametrisation of flexibility contract procurement procedures, a set of key parameters is herein considered, namely:

- Location – in the specific case of EV flexibility, location can be listed either as the corresponding connection node or the upstream substation, depending on the flexibility contract (location is especially important in voltage control) [8], [12];
- Price of the bid [12];
- Divisibility – the possibility to use only part of the flexibility offered, in terms of power activation or time duration [12];
- Accuracy – maximum allowed number of unsuccessful activations, or maximum allowed deviation for a specific key parameter [8];
- Minimum ramping capacity – minimum power in-feed (or withdrawal) per unit of time [13];
- Preparation period – period between the DSO's activation request and the start of the ramping period [12];
- Ramping period – period between a set point and the full requested change of power in-feed to (or withdrawal of) the power system [13];
- Full activation time – period between the DSO's activation request and the end of the ramping period [12];
- Validity period – period when the flexibility bid respects all technical requirements [12];
- Mode of activation – way the flexibility is triggered (manually or automatically, type of control enforced) [8], [12];
- Frequency of activation – how many times the concerned flexibility can be activated within the flexibility contract's span [8];

- Delivery period – period during which the full requested change of power in-feed to (or withdrawal of) the power system is enforced [12];
- Minimum and maximum duration of the delivery period [12];
- Minimum and maximum quantity – minimum and maximum active and/or reactive power capabilities in terms of in-feed to (or withdrawal of) the power system [12];
- Deactivation period – period between the full requested change of power in-feed to (or withdrawal of) the power system and a set point [12];
- Minimum duration between the end of the deactivation period and the following activation [12].

Additionally, flexibility contract procurement parameters pertaining to stakeholder financial responsibility, stakeholder compensation, or reporting and monitoring are also proposed [9]. In the specific case of EV flexibility, information regarding EV bidirectional capabilities is advocated as a supplementary key parameter for flexibility contract procurement [8].

2.2.5 Associated risks

In this context, the overall distribution system's risk is defined as the time interval when compliance with the network's technical limits is not ensured, leading to ENS related costs, such as fines and costs resulting from equipment repair and failure times.

Evidently, distribution grid planning according to a "business-as-usual" approach – meaning a passive network management strategy where no control action is put in place (in the specific case of EVs, this corresponds to "dumb" charging techniques) – is prone to result in such occurrences, given the network's inability to quickly respond to congestions.

On the other hand, distribution grid planning with flexibility contracts also encompasses risk, since the probability exists that the provision of flexibility is insufficient to solve a network congestion.

On this subject, a stochastic risk assessment resorting to non-network planning options has been carried out on a real portion of the Italian distribution system for the 2021-2030 horizon [14], having compared conventional grid reinforcements with multiple risk-based distribution grid planning strategies. The analysis concluded that active network management strategies – where congestions are solved primarily via EV charging postponement and small, occasional generation curtailments (and to a minor extent via DR services and active and/or reactive power modulation) – maximize total investment savings (bilateral contracts – 90 %, participation in a flexibility marketplace – 89 %), while accounting for a marginal increase in the overall distribution system's risk (bilateral contracts – 4.8 hours per year, participation in a flexibility marketplace – 4.9 hours per year) [14].

Furthermore, in the case a market-based framework for flexibility contract procurement demonstrates unacceptable levels of economic efficiency, market distortion potential, or congestion, the introduction of administrative measures might be a suitable alternative, particularly if proven to be the most cost-effective option between the two. Still, it is important to avoid information asymmetries pertaining to opportunity costs for network users, which could introduce estimation errors in the delineated compensation, ultimately leading to further inefficiencies and leveraged costs for the consumers [9].

3 A model for EV charging flexibility

Responsive services adopted by plug-in EV aggregators, either through load-shifting – V1G – or V2G, will aim at solving network congestions and, consequently, enabling the reduction in DSO operating costs, improving the operation of the distribution network and the deferral of grid reinforcement investments. To solve congestions, the DSO will request, under flexible contracts, peak shaving requests to aggregators.

Therefore, when planning distribution grids, the flexibility potential arising from EV charging loads should be considered. To evaluate such flexibility and to incorporate it into the planning tools, it is necessary to develop an EV charging flexibility model that can be promptly characterised by the planner based on limited information about its future use, being at the same time capable of representing the main features, limitations, and costs of EV flexibility. In this section, one such EV charging flexibility model is developed. The developed model enables the estimation of the main flexibility features of a given resource – here, the flexibility resources are considered to be parked EVs plugged into a charger.

To estimate the flexibility of a given flexibility resource, the proposed model will only consider four parameters: the occupancy and charging rates of the flexibility resource (introduced earlier), and the number and power capacity of the EV chargers. Furthermore, flexibility resources are homogeneous in terms of charging power, meaning that the chargers' power within a given EV charging park are assumed to be equal.

Let's start by illustrating the flexibility potential of EV charging, through an example of charging schedules and the corresponding changes in expected load, presented in Figure 4. The first plot in Figure 4 shows that an EV is connected to the charger at 8:00, being charged for one hour, from 8:00 to 9:00, and disconnected at 11:00. Therefore, such an EV has an occupancy time of three hours and a charging time of one hour. Since occupancy time is greater than the charging time, note that if the starting time of the charging event shifted from 8:00 to 9:00, as illustrated in the second plot, or even shifted from 9:00 to 10:00, as illustrated in the third plot, the EV would still charge without any discomfort to the EV user. Generalizing this example: EV users have their vehicles parked for longer periods of time than the necessary ones to charge an EV [15]; thus, if the EV supply equipment and/or the EVs can deploy smart charging strategies – that is, shift the charging period within the timeframe they are plugged in –, then EV charging loads will have high flexibility potential.

The proposed EV charging flexibility model is inspired by the work presented in [16], where the dynamic behaviour of loads of a population of EV chargers[5] is modelled using a two-dimensional lattice of cells, one dimension being the time-stamp dimension of the schedule and the other being the EV charger cardinality. Figure 5 depicts an example of a lattice representing a 24-hour charging schedule, on a 15-minute basis, of 10 EV chargers.

[5] In this text, read "EV charger" as a single charging point.

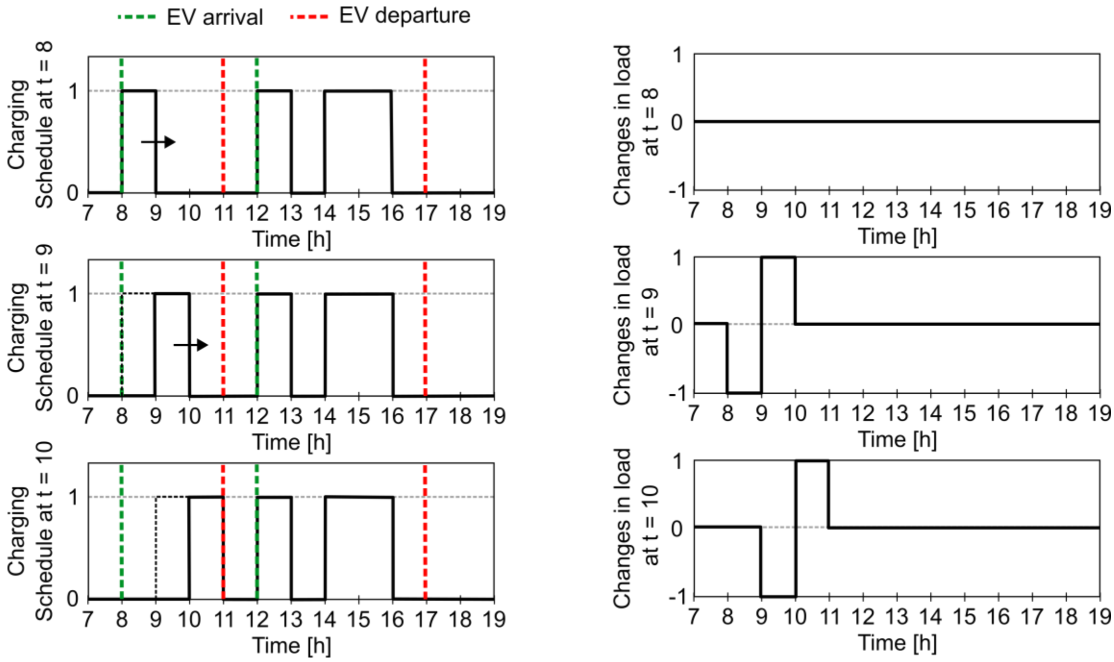


Figure 4 – Illustration of flexibility potential of EV charging loads through the shifting of charging events (middle and bottom left plots) of the original charging schedule (top left plot) and the corresponding changes in expected load (right plots).

The lattice comprises three types of cells. The first type, cells filled in white, correspond to a free EV charger (*i.e.*, no vehicle plugged-in) and will be called "empty positions". The second type, cells filled in black, indicate that an EV charger is occupied and charging an EV: "charging particles". The third type, cells filled in grey, corresponds to empty cells, indicating that an EV charger has a vehicle plugged-in but not charging: "non-charging positions". Each charging particle has the same width (referred to a time duration) and height (associated with the chargers' power). Thus, the area of a charging particle measured the charging energy. Since the chargers' power of a given EV charging park are assumed to be equal, the height of the charging particles are the same throughout the lattice.

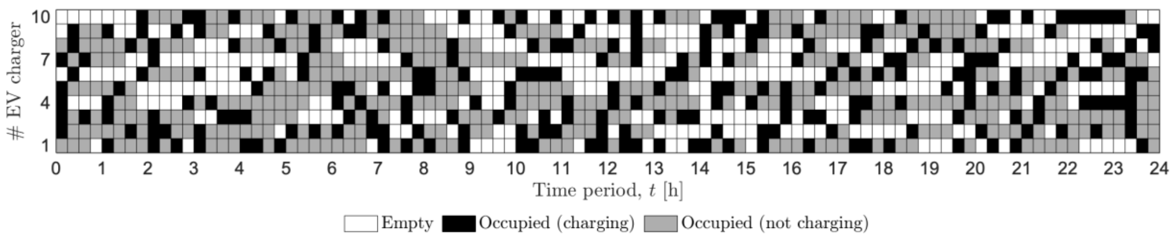


Figure 5 - Two-dimensional lattice of cells representing the original charging schedules of 10 EV chargers.

Shifting flexibility is represented in the lattice by the non-charging positions (EV charger occupied but not charging) ahead of each charging particles (EV charger occupied and charging) and can be used to regulate the chargers' aggregate load (obtained through the summation of all EV chargers' power output at each time t). Control over the aggregate load in each time t is exercised by deciding which charging particles are to be moved ahead into a non-charging position, and thus determining, in time t, the configuration of the lattice in time $t + 1$. Therefore, the process is dynamic, as both the number of charging particles available to be moved ahead in a given time t and their flexibility depend on the number of charging particles one decided to move ahead in time $t - 1$.

Since flexibility is defined as a "controlled power adjustment sustained for a required duration" [17], the correct assessment of the ability to ramp-down (and ramp-up) aggregate load of a given lattice in response to external calls for load reduction (or increase) becomes necessary to evaluate the flexibility capabilities and limitations of each lattice.

In Subsection 3.1, the formulas necessary to quantify the flexibility of a given lattice under the assumption that there is always an EV connected to each charger are provided. This situation will correspond to the maximum flexibility. In Subsection 0, the formulas are reformulated to include EV occupancy times, thus dropping the assumption of EVs always connected to chargers. Finally, in Subsection 3.3, the opportunities for the implementation of V2G strategies are explored.

3.1 Load-shifting maximum flexibility

Load-shifting maximum flexibility of a given lattice is achieved if one assumes that EVs are always connected to the chargers. It does not mean that the same EV is connected to a charger during all-day, but rather that, after disconnecting an EV from a charger, another EV is connected immediately. Under these assumptions, consider Figure 6, providing an example of a lattice representing a 24-hour charging schedules ($T = 24$ h), on a 15-minute basis ($\tau = 15$ min = 0,25 h), of 10 EV chargers is provided. Note that no empty positions are set, in comparison with the lattice in Figure 5.

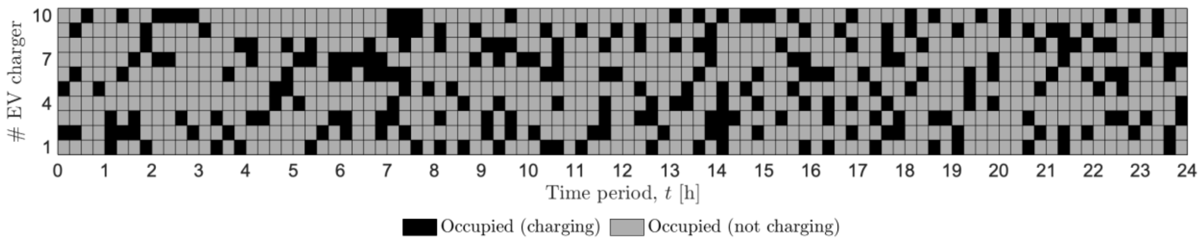


Figure 6 - Two-dimensional lattice of cells representing the original charging schedules of 10 EV chargers, under the assumption that EVs are always connected to the chargers.

Let the EV chargers be identified by $n = 1, \dots, N$, where N designates the cardinality of the population of EV chargers (in Figure 6, we have $N = 10$) and let $L(t)$ be the aggregate (normalised) demand of the population at time t, such that

$$L(t) = \sum_{n=1}^{N} x_n(t), \qquad t = 0, \tau, \dots, T - \tau, T$$
$$x_n(t) \in \{0,1\}, \qquad n = 1, \dots, N, \qquad t = 0, \tau, \dots, T - \tau, T \tag{1}$$

where $x_n(t)$ corresponds to the load demand of the n^{th} charger at time t, and let $L^*(t)$ be the target output (normalised) set for the aggregate population load in time t.

As stated previously, control over the aggregate load in each time t is exercised by deciding which charging particles are to be shifted ahead. Hence, under peak shaving services, the reduction in aggregate load necessary to yield a target L^* in time t, $\Delta L^*(t) = L(t) - L^*(t)$, can be obtained by controlling the number of particle shifts, such that

$$v(t) = \sum_{n=1}^{N} v_n(t), \qquad v_n \in \{0,1\}, n = 1, \dots, N \tag{2}$$

where $v_n(t)$ is unitary if a particle n is shifted in time t, and zero otherwise. As such, the relationship between $\Delta L^*(t)$ and the number of particle shift responses, v, is expressed as

$$\Delta L^*(t) \approx v(t+1) - v(t) \tag{3}$$

Equation (3) encloses an important conclusion. Letting v be defined as the shifting velocity (as it represents several shifts per period), changes in aggregate load must be due to changes in shifting velocity (*i.e.*, shifting acceleration).

Consider the illustration of an arbitrary peak to shave with magnitude ΔL and duration $\Delta T = T_2 - T_1$ presented in Figure 7. During the time period between T_1 and T_2, note that $\Delta L^*(t) > 0$, implying that, according to Equation (3), the shifting velocity increases until it reaches a maximum at time period T_2. Such velocity will be named maximum shifting velocity, v^*, and corresponds to the area of the peak to shave, as expressed in Equation (4). Note that the variables ΔT and ΔL in Equation (4) must be normalised.

$$v^* = v(T_2) = \frac{\Delta T \Delta L}{2} \tag{4}$$

Thus, the capability of shaving magnitude ΔL in time period ΔT will depend on the ability of the shifting velocity to yield v^*. Moreover, it follows that higher peak shavings will require higher maximum shifting velocities.

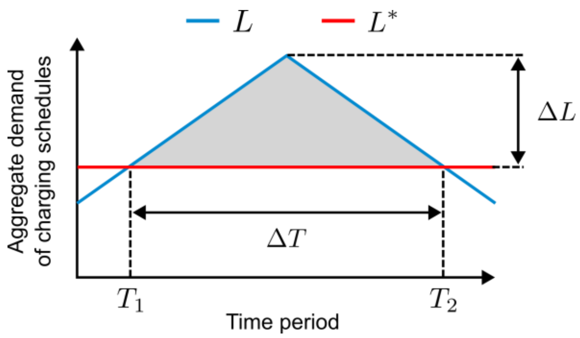


Figure 7 – Integration of the peak to shave with magnitude ΔL and duration ΔT to compute maximum shifting velocity v^*.

To roughly evaluate the ability of a flexibility resource to perform peak shaving during the time period T_1 to T_2 (*i.e.*, congestion time), we introduce the concept of charging density, d_c, defined as the average charging rate, C, during the network congestion time, such that

$$d_c = \frac{1}{T_2 - T_1} \int_{T_1}^{T_2} C(t)\, dt \tag{5}$$

To correctly perform peak shaving, it is a sufficient condition that the maximum shifting velocity, v^*, must be lower than the limit of the shifting velocity, v^{lim}, and thus

$$v^* = v(T_2) = \frac{\Delta T \Delta L}{2} < v^{lim} \quad (6)$$

where

$$v^{lim} \approx [1 - d_c]N \quad (7)$$

Hence, Equation (6) can be rewritten such that

$$\Delta T \Delta L \leq 2v^{lim} \Leftrightarrow \Delta T \Delta L \leq 2[1 - d_c]N \quad (8)$$

which encloses an important finding: by knowing the charging density of the flexibility resource during the network congestion time, the maximum value of the product of the magnitude, ΔL, by the duration, ΔT, of the peak to shave is set.

Following, an example is introduced to illustrate these concepts: consider an EV parking lot (flexibility resource) with fifty 20 kW EV chargers ($N = 50$), depicted in Figure 8. Using this information, a lattice representing the daily charging schedules (on a 15 min basis, $\tau = 0{,}25$ h) of the 50 EV chargers can be obtained. Figure 9 illustrates the obtained lattice, and Figure 8 depicts the EV parking lot's charging rate and the aggregate demand of the charging schedules, in blue and orange, respectively.

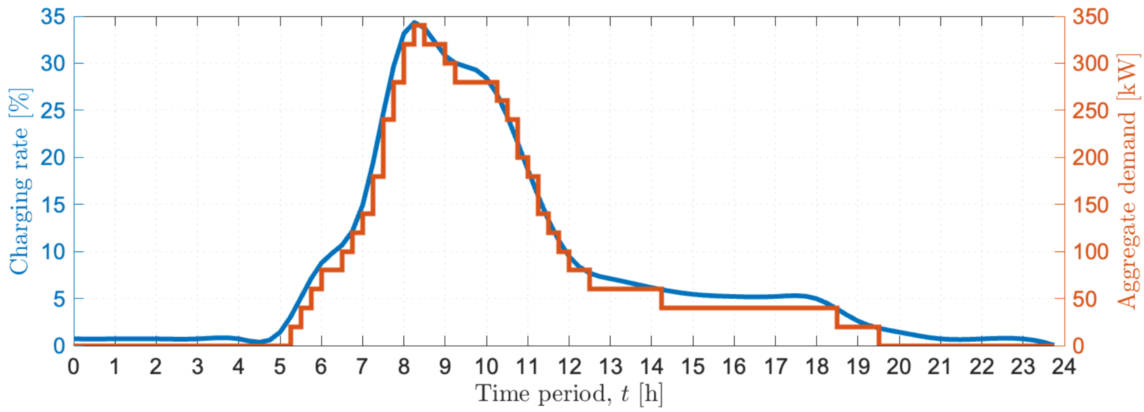


Figure 8 – Representation of the charging rate (in blue) of an EV parking lot with 50x20 kW chargers, and as the aggregate demand (in orange) of the charging schedules of the generated lattice, in Figure 9.

Firstly, let us consider a situation where peak shaving is correctly performed, as illustrated in Figure 10. The maximum aggregate demand of the charging schedules is set to 260 kW ($L^*(t) = 13$, normalised), resulting in a peak with magnitude 80 kW ($\Delta L = 4$, normalised) and duration 2,5 h ($\Delta T = 2{,}5\text{ h} / \tau = 10$, normalised) to be shaved. Consequently, during this time period, the uncontrolled aggregate demand of the charging schedule is greater than the maximum aggregate demand ($L(t) > L^*(t)$) and therefore, according to Equation (3), shifting velocity must increase, as illustrated in the bottom plot (blue line).

During peak shaving, the charging rate averages to 0.31 ($d_c = 0{,}31$), implying that, according to Equation (8), $\Delta T \Delta L \leq 69$. Since $\Delta T = 10$, normalised time units, any peak with magnitude lower than 6.9, normalised power units, will be successfully shaved. As $\Delta L = 4 < 6{,}9$, the peak is correctly shaved, as illustrated in the top plot of Figure 10. Notice also, in the bottom plot of Figure 10, that the maximum shifting velocity is lower than the limit of the shifting velocity.

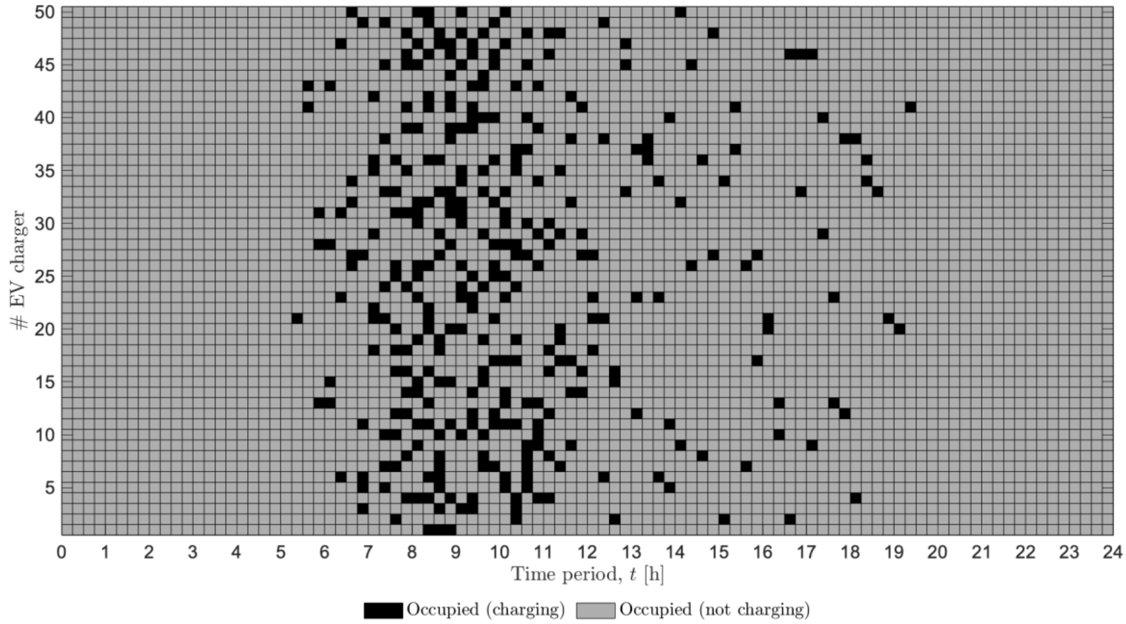


Figure 9 – Lattice representing the daily charging schedules (on a 15 min basis) of the 50 EV chargers.

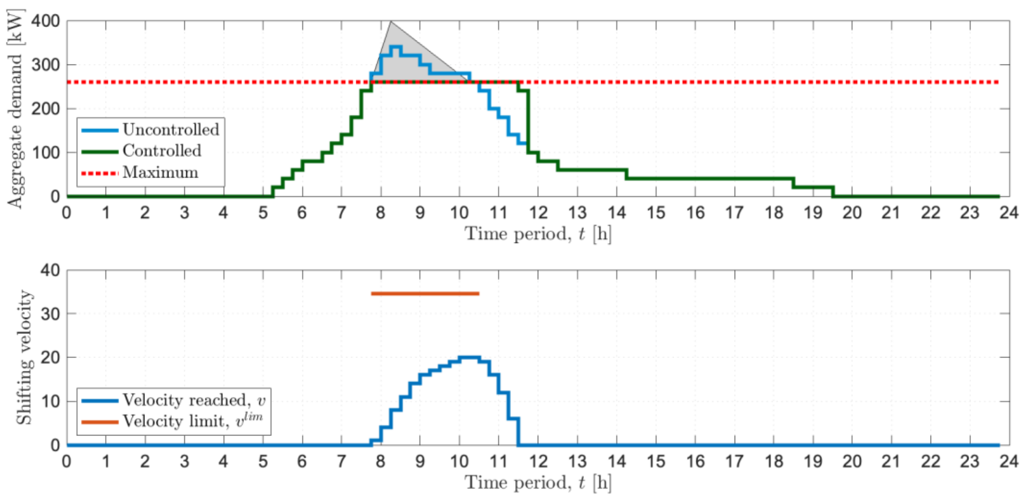


Figure 10 – Illustration of a successful peak shaving. The top plot depicts the time evolution of the aggregate demand of uncontrolled (in blue), controlled (in green), and maximum (in red) charging, as well as a visual representation, in grey, of the theoretical maximum peak that could be shaved, according to Equation (8). The bottom plot depicts the time evolution of the shifting velocity (in blue) and the limit for shifting velocity (in red).

Contrary to Figure 10, Figure 11 depicts a situation where peak shaving is not correctly performed. The maximum aggregate demand of the charging schedules is now set to 200 kW ($L^*(t) = 10$, normalised), resulting in a peak with magnitude 140 kW ($\Delta L = 7$, normalised) and duration 3.25 h ($\Delta T = 3{,}25$ h / $\tau = 13$, normalised) to be shaved. The charging rate averages to 0.30 ($d_c = 0.30$), implying that, according to Equation (8), $\Delta T \Delta L \leq 70$. Since $\Delta T = 13$, normalised time units, any peak with magnitude lower than 5.4, normalised power units, will be successfully shaved. As $\Delta L = 7 < 5{,}4$, the peak is not correctly shaved.

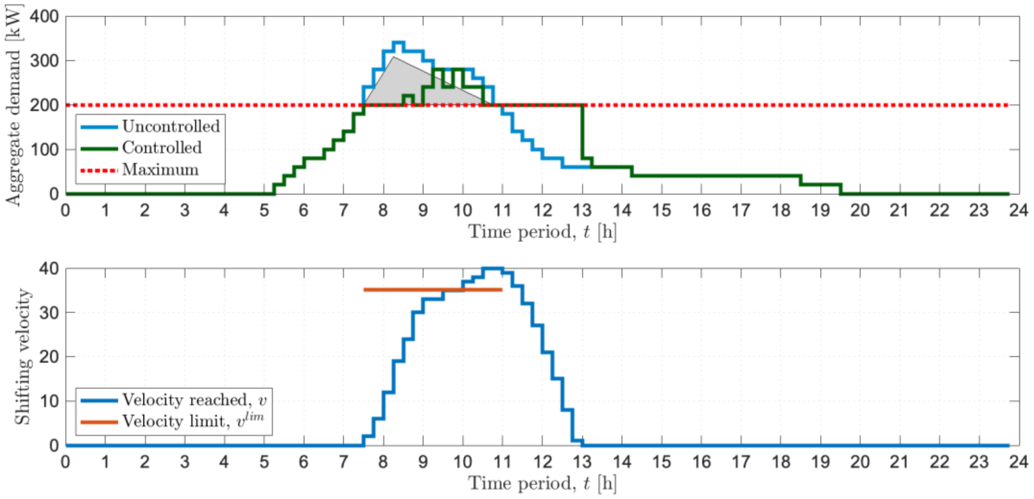


Figure 11 - Illustration of a non-successful peak shaving. The top plot depicts the time evolution of the aggregate demand of uncontrolled (in blue), controlled (in green) and maximum (in red) charging, as well as a visual representation, in grey, of the theoretical maximum peak that could be shaved, according to Equation (8). The bottom plot depicts the time evolution of the shifting velocity (in blue) and the limit for shifting velocity (in red).

The findings show that it is possible to determine the maximum magnitude of the shaved peak if network congestion time is known. To determine such magnitude, it suffices to have knowledge on the charging density during the congested time, and the number and power capacity of the EV chargers. It follows that if the uncontrolled aggregate demand is contained within the maximum peak shaved, then peak shaving is successfully performed. Such situation was depicted in Figure 10. On the contrary, Figure 11 depicted a situation where the uncontrolled aggregate demand is not contained within the maximum peak shaved, and thus peak shaving is not performed correctly.

3.2 Load-shifting flexibility with vacant periods

The results shown in the previous section were derived assuming that EV chargers were always occupied. This situation resulted in the assessment of the maximum flexibility of a given lattice. However, this assumption does not hold in reality. To solve this, in the same fashion as the charging density was defined as the average of the charging rate during peak shaving, we propose that a new parameter, named occupancy density, d_o, must be included in the assessment of the flexibility of a given lattice aiming to solve network congestions. The occupancy density is computed as the average of occupancy rate, O, during the network congestion time, such that

$$d_o = \frac{1}{T_2 - T_1} \int_{T_1}^{T_2} O(t)\, dt. \qquad (9)$$

Maintaining the definition of charging rate, introduced in the previous section, it follows that the occupancy rate must always be greater or equal to the charging rate, $O(t) \geq C(t)\ \forall t$, which in turn implies that during peak shaving the occupancy density must be greater or equal to the charging density, $d_o \geq d_c$.

To correctly perform peak shaving, the condition expressed in Equation (6) still holds true. However, when accounting for both densities, the limit for shifting velocity needs to be changed to

$$v^{lim} \approx [d_o - d_c]N. \tag{10}$$

and therefore, we have that

$$\Delta T \Delta L \leq 2v^{lim} \iff \Delta T \Delta L \leq 2[d_o - d_c]N, \tag{11}$$

and thus, by knowing both the occupancy and charging densities of the flexibility resource during the network congestion time, the maximum value of the product of the magnitude, ΔL, by the duration, ΔT, of the peak to shave is set. Note that Equation (11) turns into Equation (8) if the occupancy density is set to 1 (situation where EV chargers are always occupied).

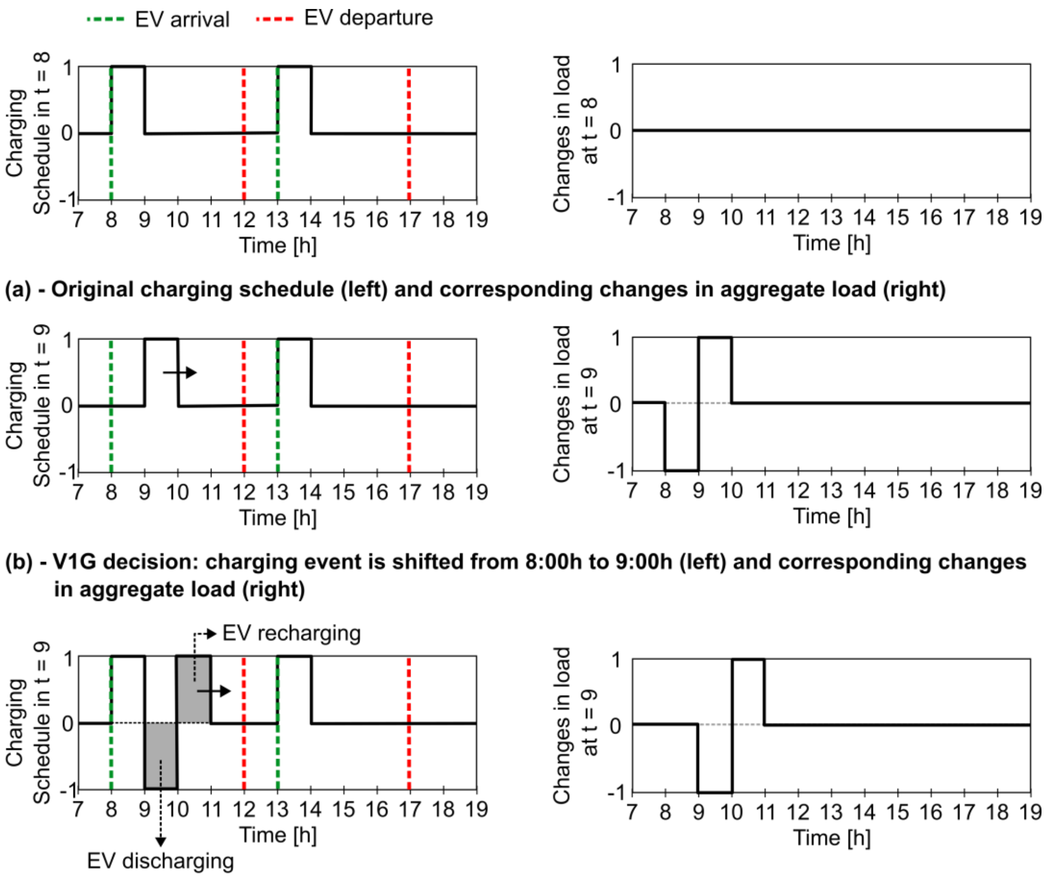
3.3 Opportunities for V2G

The models derived in the previous section only foresee load-shifting as the flexibility arising from EV charging loads, neglecting the possible value added by adopting V2G. In this section, the model is improved to consider both V1G and V2G.

Consider Figure 12, where the original charging schedule of an EV charger (top plot), the V1G smart charging option of load-shifting (middle plot), the V2G option of battery discharging (bottom plot), and the corresponding effects onto the expected aggregate load state are presented. Note the similarity between the effects of the different decision options onto aggregate load states and future decisions. In the proposed model considering a V1G decision, by shifting at $t = 8$, the load state is reduced at $t = 8$ and increased at $t = 9$, as illustrated in the middle plots. By shifting, one also gains the opportunity to shift again in a subsequent time, $9 \leq t \leq 11$.

In the proposed model considering a V2G decision, opting to discharge the battery instead of shifting its charge entails that the battery must be charged prior to discharging it. By discharging it at $t = 9$, the load state is reduced at $t = 9$ but needs to be increased in a subsequent time, $10 \leq t \leq 11$, so that the battery is recharged, as illustrated in the bottom plots. By assuming that the battery needs to be recharged, one gains the opportunity to choose the time to do so (see the bottom left plot where the greyed EV recharging box indicates the earlier recharge time and the arrow the opportunity to shift it).

Both actions have a similar effect on the aggregate load state since they both create the possibility of shifting the charge in the future by decreasing the expected load at the time of decision-making and increasing it later. The primary distinction between V2G and V1G from the standpoint of the control space is that V2G allows one to choose when to discharge (after charging), but V1G requires one to shift at the time planned for charging because one cannot postpone something already done.



(a) - Original charging schedule (left) and corresponding changes in aggregate load (right)

(b) - V1G decision: charging event is shifted from 8:00h to 9:00h (left) and corresponding changes in aggregate load (right)

(c) - V2G decision: discharging decision at 9:00h and resulting charging event at 10:00h (left) and corresponding changes in aggregate load (right)

Figure 12 - Illustration of flexibility potential of EV charging loads arising from V1G or V2G decisions.

To incorporate V2G decisions, the aggregate (normalised) demand of the population at time t, expressed in Equation (1), needs to change to

$$L(t) = \sum_{n=1}^{N} x_n(t), \qquad t = 1, \dots, T$$
$$x_n(t) \in \{-1,0,1\}, n = 1, \dots, N, t = 1, \dots, T \tag{12}$$

where the new (-1) possible value for $x_n(t)$ indicates that n^{th} charger is discharging the EV at time t. Analagously to the number of particle shifts, v, let w be the number of discharging decisions, such that

$$w(t) = \sum_{n=1}^{N} w_n(t), \qquad w_n \in \{0,1\}, n = 1, \dots, N \tag{13}$$

where $w_n(t)$ is defined to be unitary if a particle n is discharged in time t, and zero otherwise. Hence, under peak shaving services, the reduction in aggregate load necessary to yield a target L^* in time t, $\Delta L^*(t) = L(t) - L^*(t)$, is now obtained by controlling both the number of particle shifts and the discharging decisions, such that

$$v(t) + w(t) = \sum_{n=1}^{N} v_n(t) + \sum_{n=1}^{N} w_n(t) \qquad (14)$$
$$v_n \in \{0,1\}, n = 1,\dots,N, w_n \in \{0,1\}, n = 1,\dots,N$$

and therefore Equation (3) changes to

$$\Delta L^*(t) \approx [v(t+1) - v(t)] + [w(t+1) - w(t)] \qquad (15)$$

For a comparison on the ability to perform peak shaving services solely under V1G and considering both V1G and V2G, recall the example presented in Subsection 3.1, in which a parking lot comprising fifty 20 kW EV chargers, with a charging rate depicted in blue in Figure 8, was considered. Again, the maximum aggregate demand of the charging schedules is set to 260 kW ($L^*(t) = 13$, normalised), implying that, solely under V1G, peak shaving is correctly performed. Figure 13 depicts the results obtained using both V1G and V2G.

The results show the leading role of V1G over V2G, since the number of V2G discharging decisions, w, is much lower than the number of V1G decisions, v, as illustrated on the bottom plot of Figure 13. Reason lies in the fact that the capability to ramp-down aggregate load derives largely from the opportunity to shift in the future. Such opportunity can be created either by shifting a charge – V1G – or by discharging a battery – V2G.

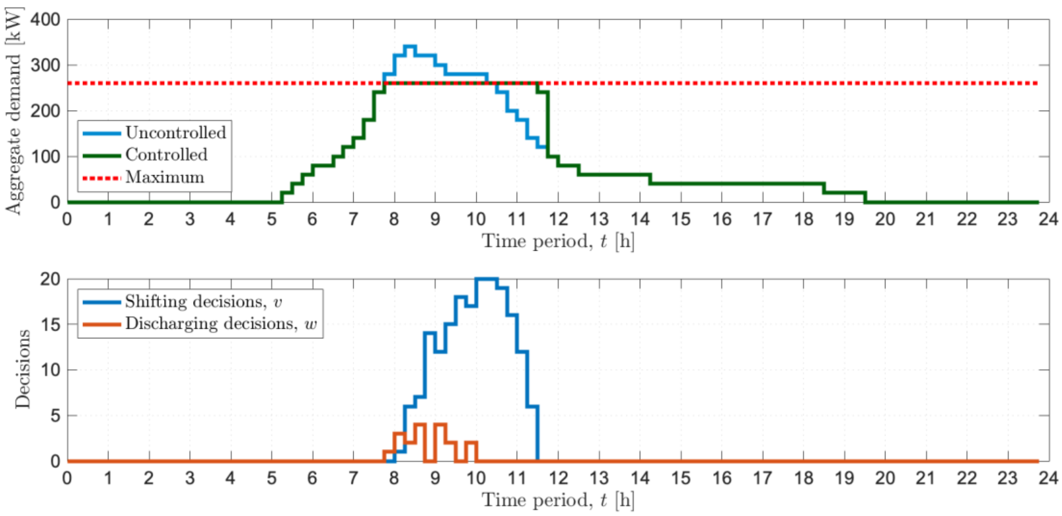


Figure 13 - Illustration of a successful peak shaving using V1G and V2G decisions. The top plot depicts the time evolution of the aggregate demand of uncontrolled (in blue), controlled (in green), and maximum charging (in red). The bottom plot depicts the time evolution of the shifting – V1G – decisions (in blue) and of the discharging – V2G – decisions (in red).

In the context of congestion management under peak shaving services, we argue that the only tangible value of V2G is its added capability to create a new opportunity for V1G to shift. But that can be more important than it appears. It may be difficult to find a large enough number of charging actions available to shift in a given time. Without V2G, the number of calls for V1G actions would steepen more abruptly to accumulate a sufficient number of shifting decisions.

4 Optimal distribution grid planning through flexibility

Incorporating flexibility into the planning tools of the future will entail changes in the evaluation and decision-making processes present in the planning tools of today. In this section we will provide an insight into the main changes that are required in traditional distribution grid planning to consider flexibility. In Subsection 4.1, we tackle the formulas related to the traditional approach to distribution grid planning and, in Subsection 4.2, we present the main changes required in the traditional distribution grid planning to incorporate EV flexibility in the decision process.

4.1 Traditional approach

From a topology point of view, the solution space for design alternatives can be represented by a graph $G = (N, A)$ in which the loads, generators, and other delivery points, as well as the points of sectioning and derivations (existing and future), are represented by a set of nodes, N, while all cables, lines, transformers, switches, and circuit breakers (existing and future) are represented by a set of arcs, A.

Design alternatives are therefore subgraphs of G that represent both the future infrastructure and the corresponding configuration chosen as the normal operating configuration within such infrastructure. Mathematically, the solution can be represented by a pair (x, y), where x represents a subgraph of G and y represents the radial operating configuration chosen within x.

$$\begin{gathered} x \subseteq G \\ y \in SP(x) \end{gathered} \tag{16}$$

where $SP(x)$ is the set of spanning trees of x. For illustration purposes consider Figure 14, in which a small-scale grid with two substations, six load points, and a switching station is presented. This grid will be used throughout the chapter for example purposes.

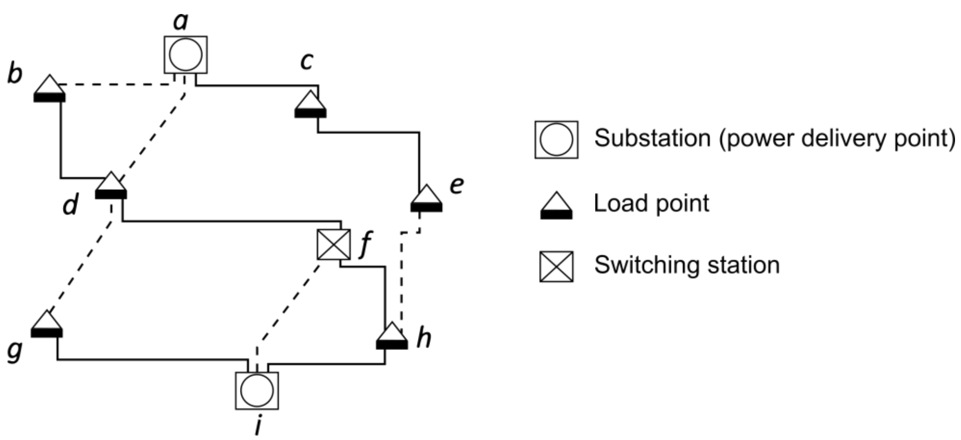


Figure 14 - Schematic representation of a standby redundant electrical grid with two substations. The dashed lines identify the grid branches not used by power-flow purposes.

The ENS is a network reliability metric, which includes the impacts of interruptions caused by network faults, in addition to the impacts of congestion on post-fault restoration. It is therefore very important to understand how reliability in a distribution network is evaluated and how congestion arising from capacity limitations in the network are translated into a quantifiable ENS.

A fault in a line section may classify as fugitive (*i.e.*, autonomously cleared, not requiring repair) or permanent, both leading to an automatic opening of a feeder breaker. In the former case, the feeder is usually reclosed successfully in a very short time and, therefore, the ENS is negligible. In the latter case, either the breaker reopens the feeder, or some line-section automatic device isolates the fault from the feeder, and the breaker recloses, supplying power to customers upstream of the isolated section. To feed the customers downstream the fault, the grid is reconfigured (when possible) by closing normally open devices. When the repair work over the faulty cable or line section is concluded, the grid can return to its original configuration.

Figure 15 illustrates the consequences of a possible fault and corresponding service restoration stages: on the left, a fault in a branch is shown and the stage that follows the automatic opening of a feeder breaker is illustrated; at the centre, fault isolation is carried out by opening the faulted branch and illustrates the stage that follows the breaker immediate closing after isolation to supply the customers upstream the fault; on the right, reconfiguration is undertaken by switching-on a co-tree arc and illustrates the stage that follows switching to supply the customers downstream the fault.

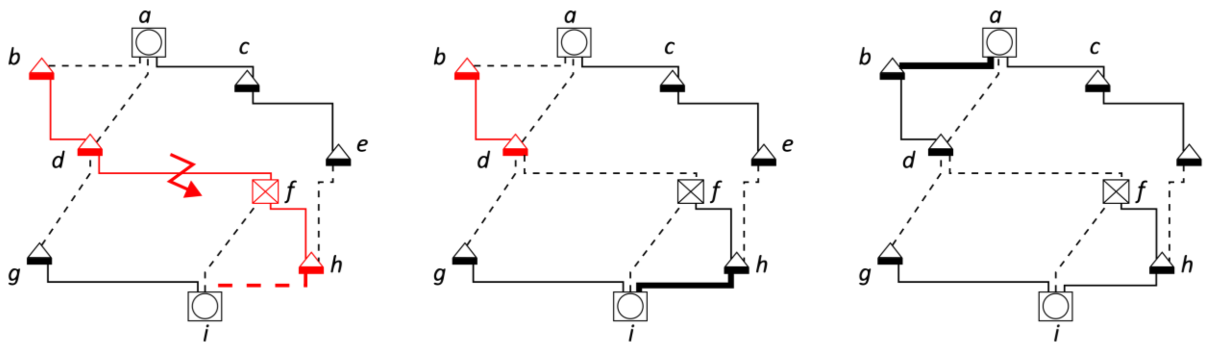


Figure 15 - Switching stages in service restoration after fault in distribution grids: (left) fault in branch $d - f$ followed by the automatic opening of a feeder breaker in branch $i - h$; (centre) fault isolation by opening branch $d - f$ followed by the breaker immediate closing to supply the customers upstream the fault, nodes h and f; (right) outage reconfiguration by switching-on arc $a - b$ to supply the customers downstream the fault, nodes b and d.

Thus, for a given loading situation, the impact of conjectural faults into reliability can be obtained by summing the ENS contributions of every restoration stage, for every possible fault, according to Equation (17), where λ_m corresponds to the failure rate of the line or cable (measured in failures per year) in branch m, and E_m to the ENS (measured in kWh), in branch m, during fault isolation and reconfiguration.

$$E^R = \sum_{m \in A(x^*)} \lambda_m E_m \tag{17}$$

In the example presented, backup capacity was assumed to be sufficient to feed the customers downstream the fault. However, under the new paradigm of “lower energy delivery under higher peak requirements”, the backup circuit prompted might not be able to feed all customers without congestion, as illustrated in Figure 16. In this situation, to guarantee security of supply, load shedding occurs during fault repair time. Thus, the ENS impact due to structural limitations caused by insufficient backup capacity is obtained through Equation (18), where ΔT_m corresponds to fault repair time in branch m, and ΔL_m to the load shed in branch m.

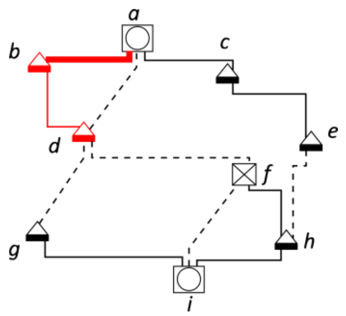


Figure 16 - Final stage of the service restoration process shown in Figure 15 considering that backup circuit prompted is not able to feed all customers without congestion.

$$E^S = \sum_{m \in A(x^*)} \lambda_m \, \Delta T_m \, \Delta L_m \qquad (18)$$

Under the two situations provided in Figure 15 and Figure 16, the ENS total value, E^T, can be expressed by a conditional sum of the two impacts: the impact of conjectural faults, E^R, and the impact of structural limitations, E^S, such that

$$E^T = \begin{cases} E^R + E^S, & \Delta L > 0 \\ E^R, & \text{otherwise} \end{cases} \qquad (19)$$

As both impacts are mapped into ENS values, the structural limitations of a grid can be evaluated as an ENS impact. Being an ENS impact, the marginal kWh cost of ENS enables the valuation of structural limitations of a grid which, if mapped into monetary value, are used to search for adequate capacity. Adequate capacity is a trade-off between capital costs in grid asset reinforcements and capacity costs measured as improvements in ENS costs.

Traditionally, utilities or regulators set an economic value per kWh of ENS and use this value to trade-off ENS costs against grid reinforcement and expansion costs. The trade-off includes other operational costs that are significantly impacted by grid reinforcement such as energy losses costs, valuated at the economic value of energy at the grid's voltage level.

The trade-off between reliability, energy losses, and the investment in grid reinforcement and expansion can be obtained by searching for the minimum of the corresponding costs, by solving the minimization problem $\mathcal{P}$, such that

$$\begin{aligned} &(\mathcal{P}) \\ &\min_{(x,y,p)} \quad R(x,y,p) + S(y,p) + I(x,p) \\ &\text{s.t.} \quad x \subseteq G \\ &\qquad\;\; y \in S(x) \\ &\qquad\;\; p \in \mathcal{C}(x) \end{aligned}$$

where $\mathcal{C}(x)$ is the set of possible characteristics for the equipment in the arcs of x, R represents the ENS cost function (reliability cost function), S represents the energy losses cost function, and I represents the capital cost function of grid investment. Such cost functions need to be evaluated within a given horizon, being the target designated by H. Figure 17 illustrates the relationship between evaluation and decision-making tasks in traditional distribution grid planning.

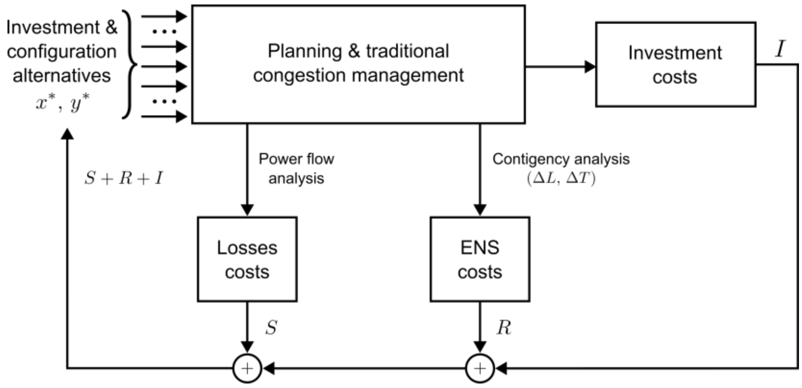


Figure 17 – High-level representation of the relationship between evaluation and decision-making tasks in traditional distribution grid planning.

The expected value of ENS is usually computed for the target year H, while the annualized costs of reliability are determined for known load growth and discount rates for a given marginal kWh cost of ENS. The same happens for the energy losses costs. The value of energy loss is usually computed for the target year H, while the annualized costs of losses are determined for known load growth and discount rates for a given economic value of energy at the grid's voltage level.

The value of the investment cost is usually computed assuming that the whole investment is made in the starting year. As most investments in new grid assets have a lifetime longer than the planning period, one must consider a residual value for such assets at the end of that period. Therefore, the investment cost in the planning period must be computed as the difference between the investment cost in the starting year and the current residual value, given a discount rate.

Suppose that minimal capacity reinforcements were found previously for the target year of the planning horizon, in other words, that one had already solved problem R and determined $x^* \subseteq G$ and $p^* \in \mathcal{C}(x)$. Consider that the existing grid equipment is represented by a set of parameters of graph x^* in time $t = 0$ and that such set is designated by $p^0 \in \mathcal{C}(x^*)$. The set of equipment additions to graph x^* represented in p^* can then be designated by p^+, where

$$p^+ = p^* \backslash \{p^0 \cap p^*\} \tag{20}$$

After solving problem $\mathcal{P}$ and obtaining (x^*, p^*), the problem of optimal timing for capacity reinforcements can be formulated as the problem of assigning a timing t to each equipment addition of p^+. Denoting equipment additions of p^+ in time t by p_t^+, and the cumulating additions until time t by p_t^*, such that

$$p_t^* = \bigcup_{i=1}^{t} p_i^+ \tag{21}$$

the problem of optimal timing for equipment additions can be formulated as the problem of distributing over the H years of the planning horizon considering all optimal additions, p_H^*, that were found by solving problem $\mathcal{P}$. The problem can be formulated as in $\mathcal{R}$, where α is the discount rate.

$(\mathcal{R})$

$$\min_{(y,p)} \sum_{t=1}^{H} \left(R(x^*, y_t, p_t^*) + S(y_t, p_t^*) + I(x^*, p_t^+) \right) \frac{1}{(1+\alpha)^t}$$

$$\begin{aligned} \text{s.t.} \quad & p_t^+ = p_t^* \backslash \{p^0 \cap p_t^*\} \\ & p_H^* = p^* \\ & y = [y_t] : t = 1, \dots, H \\ & y_t \in S(x^*) : t = 1, \dots, H \end{aligned}$$

4.2 Planning with flexibility

If part of the consumption or production connected to a network is flexible, in the sense that it can be modified in a given period, the network operator can take advantage of this flexibility to reduce or even eliminate some overloads, and thereby avoid interrupting customers as a consequence of load shedding. As contributors to the supply, flexible customers can be seen as capacity providers and deployed to postpone grid reinforcements. Figure 18 illustrates the aggregate result of modifying the daily consumption diagram for a set of customers connected to the same feeder in response to a request to reduce consumption to comply with a capacity constraint on that feeder.

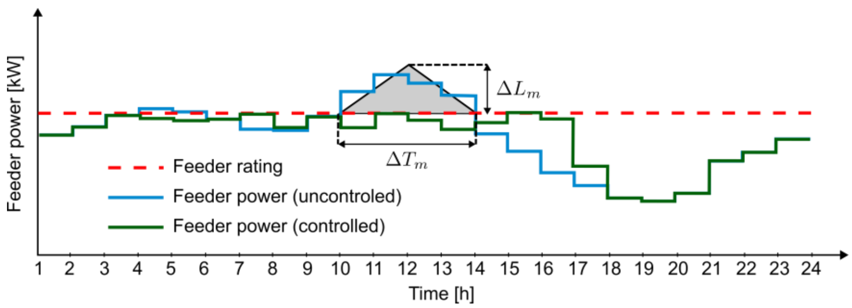


Figure 18 - Power in a feeder cable that results from flexible customers incentivized by peak shifting tariffs. Results for the uncontrolled (original) load are shown in blue and tariff optimized (response) results are shown in green. The optimized aggregated responses lead to a profile that does not exceed the cable current rating (dashed line), allowing feeder reinforcement to be postponed or avoided.

From the design perspective, customer flexibility under flexibility contracts can be used to reduce peak loading and, in this way, improve capacity adequacy. Capacity adequacy is evaluated by the reliability function, $R(x^*, y_t, p_t^*)$, in which the ENS is given by a conditional sum of two impacts: the impact of conjectural faults, E^R (which does not depend on the network capacity), and the impact of structural limitations, E^S (which depends on the network capacity and therefore in the equipment p), according to Equation (19).

From the reliability cost function perspective, the impact of grid structural limitations is mitigated by flexible resources if the load ΔL reduction that is necessary to eliminate overloads can be undertaken at a cost lower than the ENS cost. Note that the solution of $\mathcal{P}$ already traded-off reliability costs R of load shedding against reinforcement investment costs, *I*. The solution (x^*, p^*) is optimal regarding such trade-off. However, if structural limitations consequences such as those measured by E^S can be mitigated with flexible resources, then some reinforcement investments found optimal in $\mathcal{P}$ may not be true anymore. Or, by still being optimal, meaning that the solution (x^*, p^*) is maintained, will lead to different equipment additions timings p_t^+, when solving problem $\mathcal{R}$.

To address the problem of optimal timing considering flexible customers as capacity enablers, problem $\mathcal{R}$ has to be reformulated to include the costs and benefits of that flexibility. That is done by changing the way one valuates capacity adequacy in the reliability cost function, *R*, and adding a new cost function for flexibility, *F*.

A possible way to undertake such change is to keep the definition of E^S unchanged, and to redefine the load shed in branch m as

$$\Delta L_m \coloneqq \max\{0, \Delta L_m - D_m\} \tag{22}$$

where D_m represents the sum of demand for flexibility resources from customers downstream of the overload and upstream of the branch m, after branch isolation and service restoration. The redefinition of the load shed condition to include flexibility resources assumes that D_m resources are known *a priori* for each node in the network, in the same way as loads and many other network parameters.

To quantify D_m, let N_{s-m} be defined as the set of nodes in the network bounded downstream by the overloaded branch s in the post-fault configuration found to isolate the faulted branch, m. For illustration purposes, consider Figure 19 in which the nodes of the set N_{s-m} (contained in blue circles) are presented for a fault on branch $m \equiv d\text{-}f$ and a post-fault configuration that gives rise to an overload on branch $s \equiv a\text{-}b$.

Using the definition of the set of nodes N_{s-m}, the demand for flexibility resources D_m is defined as

$$D_m \coloneqq \sum_{\substack{k \in N_{s-m} \\ \pi_k < \gamma}} D_k \tag{23}$$

where π_k corresponds to the marginal kWh cost of flexibility resource k, and γ to the marginal kWh cost of ENS.

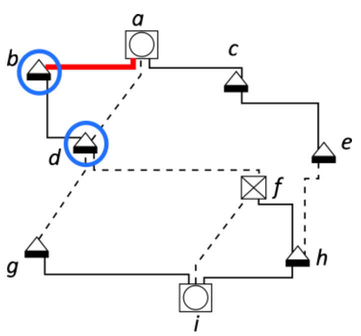


Figure 19 - Final stage of the service restoration process shown in Figure 15 for a fault on branch $m \equiv d\text{-}f$. In the post-fault configuration, the potential flexibility resources, D_{d-f}, likely to resolve the overload at branch $s \equiv a\text{-}b$, are identified in blue circles.

To assess the value of D_k for each $k \in N_{s-m}$, recall Equation (11), in which a relationship between both occupancy and charging densities (d_o and d_c, respectively) and the product between the magnitude and duration of a peak to shave was established, as to characterize the flexibility of a given flexibility resource. Thus, considering a flexibility resource $k \in N_{s-m}$, and by knowing its occupancy and charging densities during the network congestion period, the maximum peak magnitude of that resource, D_k, can be determined through

$$D_k = \frac{2[d_o - d_c]N}{\Delta T_m} \quad (24)$$

since the duration of the overload due to service restoration after isolation of branch m, ΔT_m, is known. Having defined D_m, the flexibility cost function can be expressed as

$$F = \sum_{m \in A(x^*)} \{\lambda_m \pi_m^* D_m^* \Delta T_m\} \quad (25)$$

where π_m^* represents the clearing price for the procured flexibility ΔL_m assuming the identified resources $\{D_k\}$ that compose D_m bid each its own price π_k. The value of π_m^* will depend upon the auction mechanism chosen to clear the supply $\{(D_k, \pi_k)\}$ against the procured flexibility ΔL_m (pay-as-clear, pay-as-bid, or other).

Once the flexibility cost function F is defined, the optimal-timing problem that considers flexibility resources in congestion management can now be reformulated as $(\mathcal{S})$, such that

$$(\mathcal{S})$$

$$\min_{(y,p)} \sum_{t=1}^{H} \left(R'(x^*, y_t, p_t^*) + S(y_t, p_t^*) + I(x^*, p_t^+) + F(x^*, y_t, p_t^*)\right) \frac{1}{(1+\alpha)^t}$$

$$\begin{aligned} \text{s.t.} \quad & p_t^+ = p_t^* \backslash \{p^0 \cap p_t^*\} \\ & p_{H+1}^* = p^* \\ & y = [y_t] : t = 1, \dots, H \\ & y_t \in S(x^*) : t = 1, \dots, H \end{aligned}$$

where R' corresponds to the modified reliability cost function, F to the flexibility cost function, and $H + 1$ represents a stage after the target year which will be used to allow previously determined reinforcements in p^* to be discarded in the considered planning horizon. Figure 20, derived from Figure 17, illustrates the main changes (represented in blue) required to modify traditional distribution grid planning into new planning approaches that make use of EV flexibility charging to mitigate network congestions.

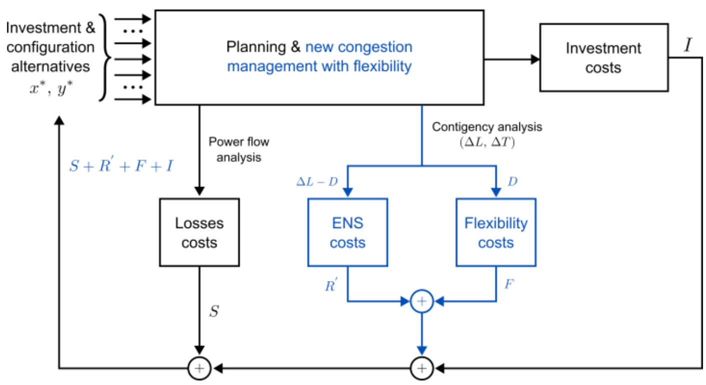


Figure 20 – High-level representation of the main changes required (in blue) to modify traditional distribution grid planning into new planning approaches that make of use of EV flexibility charging to mitigate network congestions.

The proposed methodology for incorporating EV flexibility into the decision-making process of distribution grid planning assumes a high penetration of EVs and the possible creation of EV aggregators, which faces many challenges and barriers as of today [17]. Despite this, some DSOs have already started procuring flexibility contracts through a market-based framework, via long-term bilateral contracts, as explained in Subsection 2.2. The flexibility platform *Piclo Flex* [18] supports this approach, which has been embraced by the UK's DSOs [17]. French DSOs [19] have also led comparable initiatives in an effort to contract flexibility for congestion management and post-fault restoration.

The procurement of flexibility contracts in platforms such as *Piclo Flex* requires the value of flexibility provision to be captured by the DSO prior to bidding. To capture such value, DSOs begin by planning distribution grids using a traditional approach, thus obtaining the optimal value for the cost function, $S + R + I$ (as illustrated in Figure 17). Afterwards, DSOs re-plan the grid assuming that some flexibility, D, will be available to be procured, thus obtaining a solution where the total cost, $S + R' + I$, is expected to be inferior to the original solution. This may be represented in Figure 20 by neglecting the flexibility cost function in the optimization process, as illustrated in Figure 21, and by evaluating reliability as if flexibility, D, were available. The value of flexibility is then captured from the difference between the total cost function of the original solution, $S + R + I$, and the total cost function of the solution that assumes that flexibility is available, $S + R' + I$.

DSOs current planning approach to flexibility, as described, is based on a contrafactual valuation of flexibility. It requires splitting the decision-making process into two consecutive phases: one for searching for optimal reinforcement investment decisions that can be avoided or deferred, and another to procure the flexibility that makes the deferred investment solution acceptable from the operational standpoint. This is not the approach taken in the methodology proposed in this chapter.

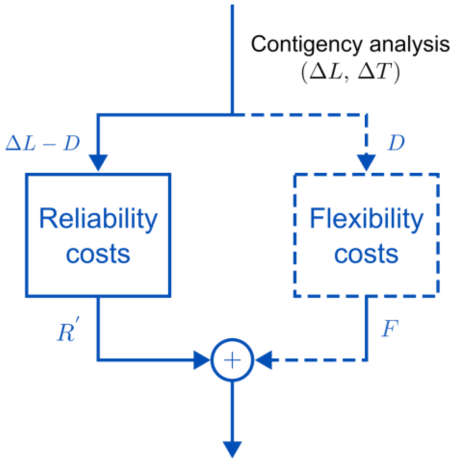


Figure 21 – Changes required in the high-level representation in Figure 20, in order to capture the value of flexibility. The dashed lines implies that flexibility costs are removed.

In this chapter, the traditional planning methodology has been evolved to search for grid solutions in which flexibility resources' capabilities and corresponding costs are previously known or possible to scenarize in the future, just like loads, generators, and any other distributed resources. In the evolved optimization process, solutions are found trading off investment costs against flexibility costs and other operational costs, without having to split decision-making into two consecutive phases, this way avoiding suboptimal solutions that inevitably result from decomposition.

5 Conclusions

In previous decades, grid dimensioning was considered optimal when the network demonstrated minimum losses – determined in reference to the expected ("dumb") loads connected to it – and, thus, evidenced great backup capacity. If the same approach were to be applied to modern grids, with its higher peak loads and decreased load factors, infrastructure would be oversized and suboptimal. The key is then to consider flexibility as an alternative to immediate investment.

In the context of grids with large-scale EV penetration, flexibility is mainly characterized by the shiftability (over time) of the charging sessions, turning EV users into capacity enablers and compensating them for being so. However, as EVs aren't primarily a grid asset, flexibility contracts must be designed, considering technical, economic, regulatory, and user dimensions.

Another important finding made is that, in the perspective of grid planning, charging load shifting and V2G are conceptually similar, and that V2G mostly takes place when no other shifting opportunities are available, becoming a second resort to mitigate network congestions. Nevertheless, in other settings, such as self-consumption, energy communities, and facility energy management, the role of V2X may prove not to be secondary in addressing the installations' particular needs and characteristics.

Finally, the EV flexibility charging model can be integrated into the grid planning optimization problem. This methodology searches for grid solutions that trade off investment costs against flexibility resource costs and other operational costs. Thus, the impact of grid structural limitations is mitigated by flexible resources if the load reduction that is necessary to solve network congestions can be undertaken at a cost lower that the ENS.

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