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RESEARCH ARTICLE

Distribution Systems as Catalysts for Energy Transition Embedding Flexibility in Large-Scale Applications

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ABSTRACT Reaching the European climate target is a complex and multifaceted challenge that involves different sectors and requires coordinated efforts at various levels. Increasing the share of renewable energy sources in the energy mix and the electrification of final energy uses in all sectors represent viable solutions for the energy transition. Distribution networks are expected to be strongly influenced by and influence such transformation while withstanding progressively increasing climate impacts, and this will require a revolution at the Power System level, starting from the planning phase. The future roadmap of a power distribution system shall include not exclusively network upgrades but also non-network solutions focusing on operation strategies exploiting the flexibility gathered from distributed energy resources. To design new transition-ready planning tools for distribution systems able to consider these aspects, the role of flexibility has been analyzed on a real-world, large-scale test case characterized by a high number of connection requests and an expected high yearly electrification rate. Stress has been put on correctly assessing the value of flexibility in planning the distribution system development. One of the most important findings is that flexibility can be a valid option in helping grid management but, most importantly, an opportunity to reconsider planning by applying a new revolutionary risk-oriented approach that may lead to modify the way distribution grids have been planned and operated so far. This emerges as the disruptive value of local flexibility utilization, besides the engagement of all players, that is necessary for the completion of the energy transition.

INDEX TERMS Distribution network, flexibility, planning, risk assessment.

I. INTRODUCTION

To meet the ambitious European climate targets to cut greenhouse gas emissions by at least 55 % and make the EU climate-neutral by 2050, how energy is produced and consumed has to change [1]. The direct impact on power distribution development and operation is twofold. On one side, most renewable energy sources (RES) will be connected to distribution systems. The estimates are that 70 %-80 % of the new generation in the EU (around 400 GW) will be connected to MV and LV distribution systems. Conversely, since electrification emerged as a crucial economy-wide tool for reducing emissions, most EU efforts focus on electrifying heat production in residential, commercial, and tertiary sectors and industries. Furthermore, producing e-fuels, hydrogen, and ammonia with green electricity can foster the

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indirect electrification of the most hard-to-abate sectors but increases the burden on the distribution system [2], [3], [4].

Sustainable mobility is a pivotal EU goal for the energy transition to cut emissions up to 50 % in 2030 compared with 2021. Electric vehicles (EVs) are growing fast thanks to the falling CAPEX and OPEX [5], [6] and they are expected to account for over 60 % of all vehicles sold globally by 2030. Consequently, operational public charging points will be connected by at least 3.4 million (or even more in the most conservative scenario) by 2030 [7]. As per estimates, Europe's total electricity consumption from EVs will rise from about 0.03 % in 2014 to 9.5 % in 2050 [8], mostly burdening the MV and LV distribution. Regarding the other transportation sectors, surely the cold ironing of ports, the electrification of ferry boats, and the production of e-fuels, hydrogen, and ammonia will increase the demand for electric power but with less impact on power distribution. The improvement in energy efficiency partially absorbs the expected increase in electrical demand. For example, the EU country members are committed to ensuring an 11.7 % reduction in energy consumption by 2030 compared to 2020 [9]. The impact on the distribution system is critical; over 400 B€of investments are expected [10] due to voltage regulation, power congestions, reverse power flows, and, particularly in the LV networks, imbalances, and power quality [11], [12], [13]. DSOs are pivotal in renovating the existing assets to increase the hosting capacity for smoothly connecting utility-scale renewables plants, distributed generation (DG), and new loads while ensuring overall system climate-proofing [14].

Financial resources, permitting, and supply chain readiness are the most prominent challenges that DSOs will face, without forgetting the impact on the quality of service and life in highly anthropized areas that a colossal amount of coincident works in progress might affect.

In this frame, resorting to the flexibility of generation and consumption can unlock the possibility of postponing, if not avoiding, a fair portion of the investments needed to cope with temporary violations of technical limits in power distribution. Most of these temporary violations can indeed be easily managed by resorting to flexible resources connected to distribution systems, such as DG, thermal and electric storage systems (including EVs), and flexible demand response management systems. Here, flexibility refers to the capability and willingness to change Distributed Energy Resources (DER) power patterns in response to external signals, such as price or activation signals [15], [16], [17], [18], [19], [20], [21]. As a result, DSOs are adopting approaches to assess the benefits of flexibility compared with traditional solutions for distribution operation and planning [22], [23], [24], [25], [26], [27].

This paper analyzes at a significant scale the costs and benefits of the new distribution approach embedding flexibility, an option to be assessed and compared in the short and the long term. An entire real regional distribution network in the south of Italy (all data are anonymized for privacy reasons) was studied considering the changes in production and demand patterns determined by a vast electrification and a massive production of green energy by using a specific planning process based on a probabilistic risk-oriented approach capable of finding the optimal development in a prefixed time horizon. The continuity of service and the role of flexibility in unlocking the network capacity constraints to enable backup feeding in the event of faults are explicitly considered in the paper.

The main contribution is analyzing the real impact of modern planning models and processes embedding flexibility on developing a distribution system able to serve progressively increasing green generation and electrification over time. Indeed, most papers dealing with flexibility use are focused on small-size examples to test the quality of the proposed methodologies, or when large-scale information exists, the results are based on the existing energy patterns and not on the long-term projection of energy scenarios.

The paper is organized as follows: Section II describes the status of applying flexibility in the distribution systems. Section III describes the evolution of distribution network planning, underlining imperative aspects to be included in modern planning tools. Section IV describes the planning methodology used for including flexibility. Section V explains the energy scenarios assumed and gives the information on the network dataset. Finally, Section VI presents the results of the methodology for the dataset. Final remarks on the worth of flexibility and the planning methodology conclude the paper.

II. FLEXIBILITY IN POWER DISTRIBUTION

Flexibility usage in the distribution system has been limited or even not allowed in many countries, mainly where DSOs are regulated entities. The operation of MV and LV systems has been limited primarily to network automation to increase service continuity. Only recently, with the deployment of new ICT technologies and the connection of large quantities of DG, the use of services from consumers and producers has started to be considered by Regulators and DSOs as a viable option suitable for reaching the energy transition goals. A coordinated effort is indispensable between DSOs and Transmission System Operators (TSOs), who seek flexibility to counterbalance the non-dispatchability of increasing RES shares in the system [15]. The proper coordination and integrated planning of transmission and distribution systems are, as a matter of fact, at the core of many research projects since it is crucial for accepting a high share of green generation.

DSOs can purchase flexibility in several ways (e.g., connection agreement, network tariffs, and market). Article 32 of the EU electricity market directive recognizes market-based procurement as the most suitable option since the procurement of flexibility on a competitive basis can ensure lower costs than other options [28]. Following this, several research projects started investigating possible forms of flexibility market development, and suitable exploitations (i.e., pilots) were carried out in some of the participating countries

[21]. These proposals were characterized by different parties involved (DSO, TSO, or both), different coordination schemes between TSO/DSO, different timeframes, the type and frequency of congestions, and services and products offered. Some researchers focused their studies on the relationship between the TSO and DSO involved, defining the roles and responsibilities of each system operator when procuring and using services [21] and identifying different coordination schemes [29], [30], [31], [32].

Some flexibility markets have already been developed and field-tested, like in France (ENEDIS flexibility tenders), Germany (the ENERA Flexmarkt), the Netherlands (GOPACS), Norway (NorFlex), Sweden (sthlmflex), and Great Britain (with five tenders) [33], [34], [35]. Piclo, a British independent marketplace, has been chosen to deliver Italy's first local flexibility market and provide the end-to-end solution to acquire and dispatch flexibility services to solve local constraint issues by the largest DSO.

To support the adoption of flexibility and ensure transparent service procurement by network operators, tools for evaluating the benefits of flexibility exploitation and comparing them with traditional solutions different strategies have been developed. In some cases, such comparisons are required by law, and Regulators provide the tools for assessing the value of flexibility exploitation. For instance, in the UK and Ireland, the Energy Networks Association (ENA) published the Common Evaluation Methodology and an Excel file for network investment decisions [22], [36]. In Norway, grid companies must conduct a socio-economic cost-benefit analysis for each planning option, including investment, operation, maintenance, energy losses, interruption, and congestion costs [23]. The leading French DSO adopts a methodology to assess whether flexibility can compete with network investments, helping the planners focus on promising flexibility only [26].

A cost-benefit analysis approach based on the Joint Research Centre methodology for smart grids is proposed in [24]. In [25], a joint multi-criteria cost-benefit analysis is presented. This approach is available for all the stakeholders interested in comparing different planning solutions.

III. DISTRIBUTION PLANNING EVOLUTION

Traditionally, distribution networks were planned to solve at the planning stage all possible network violations (e.g., excessive overvoltage or voltage drop conditions, cable thermal limit exceeding), resorting exclusively to copper and iron options (i.e., resizing of conductors and substation transformers and construction of new connections and substations) [37]. This fit-and-forget (FF) DSO's policy identifies the worst-case scenario (i.e., simulating the network with maximum load and no generation or considering entire generation and minimum load) and designs a network to sustain the worst case. Therefore, FF led to network overcapacity since it does consider the probability of network constraint violations for rare operating conditions and laid down physical countermeasures. In recent years, the deployment of DG, mainly fed by RES, characterized by an intrinsic uncertainty, and the increasing presence of energy-intensive loads is making such a deterministic approach unsuitable due to the high costs of implementation and management and is leading as a consequence to new planning approaches [37], [38]. Working groups of technical associations (e.g., CIGRÉ, CIRED, IEEE) agree on adopting a new planning methodology for the modern distribution network [21], [37], [39] that includes the flexibility from generator dispatch, demand-side integration, control of transformer tap changers, reactive power management, and online reconfiguration as a development option to be considered both technically and financially. Based on these considerations, planning the evolution of the distribution system must embrace the following approaches:

- **Modeling of energy demand.** The snapshot of a single operating condition is unsuitable for investigating the worth of the flexibility from DERs. Furthermore, intertemporal load correlations can be captured only by adopting a suitable time series and georeferenced load/generation forecast [40].
- **Georeferenced forecasting.** Geographic Information System (GIS) allows the characterization of the analyzed area. It enables the representation of distribution systems in deep detail (gathering crucial technical information and locations of the assets) and managing relevant information about customers (i.e., billing information) to determine the areas for a potential network expansion. Such information merged adequately with other data (e.g., number of buildings, number of cars) could be used to create bottom-up scenarios coherent with the National Energy and Climate Plans (NECPs) [41], [42], [43].
- **Risk assessment.** The FF assumed that the worst case could be easily identified. Once the worst case was found, the system design would have been simple and effective. With thousands of DERs connected to any distribution network, the approach is no longer helpful, and an explicit risk assessment should be used instead of looking for zero-risk solutions. Planning the development of a distribution network and keeping the overall risk of technical constraint violations below a predefined allowable level is now the goal. Therefore, each planning option shall be characterized not only by its cost but also by its impact on the risk profile.
- **Probabilistic calculations.** A probabilistic network calculation based on the stochastic representation of customer behavior is essential for this risk assessment [9], considering the uncertainties on renewable generation, load demand, and incoming local flexibility markets. Depending on the stochastic distributions assumed (i.e., Gaussian, Beta, Rayleigh, etc.), network calculations can be performed with probabilistic load flow algorithms or Monte Carlo simulations. Robust optimization is gaining popularity, being probability density-free.
- **Flexibility vs Copper and Iron development.** Assessing non-infrastructural options to compare with traditional copper and iron is crucial in modern planning.

Indeed, building a new line or installing a new transformer has a well-known profile regarding costs, benefits, and risks. Instead, using flexibility from external resources is still an unfamiliar planning option for DSOs.

Following the above-mentioned approaches, modern distribution planning models incorporate the concept of risk for dealing with uncertainties. Some deal with the risk of supply-demand inadequacy [44], and other papers associate the concept of risk with the occurrence of extreme events through a risk-based optimization approach based on the conditional value-at-risk (CVaR) [45]. CVaR is also used in [46], in which the presence of RES and EVs characterizes multi-period planning of distribution networks to manage fluctuations in generation cost and carbon emissions. CVaR is also considered for the operational scheduling of electric vehicle parking lots [46] to deal with the risk of an incorrect flexibility forecast [47]. In [48], the authors propose a robust optimization over an uncertain set of scenarios to estimate the need for flexibility and avoid over-procurement.

Very little research focused on the risk concept as the main driver in making decisions to minimize the probability of violating technical constraints associated with a specific network planning configuration. In [49], a risk assessment method for estimating voltage drop risks associated with grid development strategies is proposed. In [50], the scheduling of the active distribution network (ADN) is managed by the distribution network operator, which controls distributed resources and optimizes their operation to minimize the overall costs of risk and operations. Overload violation risk cost is a financial cost due to the cost of countermeasures needed to avoid overload violation. The Authors developed a tool that compares planning solutions based on DER flexibility with traditional grid reinforcement, comparing each option's value with an acceptable risk level [27].

IV. RISK-ORIENTED PLANNING AND FLEXIBILITY

Adopting a risk-oriented planning procedure is, as mentioned, a crucial aspect of the future design of a distribution system characterized by high uncertainty. The risk of violating any technical constraints associated with a specific network planning configuration is, for this reason, explicitly assessed (flow chart of FIGURE 1).

Following the first key point of the flow chart of FIGURE 1, daily profiles are used for generation and demand. Each profile is discretized in 24 hours, and the uncertainty in the power consumed or generated is modeled through Normal probability density functions. It must be observed that the standard deviation values adopted for the 24 hours of a specific typical day depend on the year portion represented, i.e., on the number of typical days considered. In the proposed methodology, a linearized Probabilistic Load Flow (PLF) is solved for each of the 24 hours of the typical days, both in normal operating conditions and in all the emergency configurations obtained by removing one network element at a time according to the classical N − 1 analysis [51]. Thanks to the

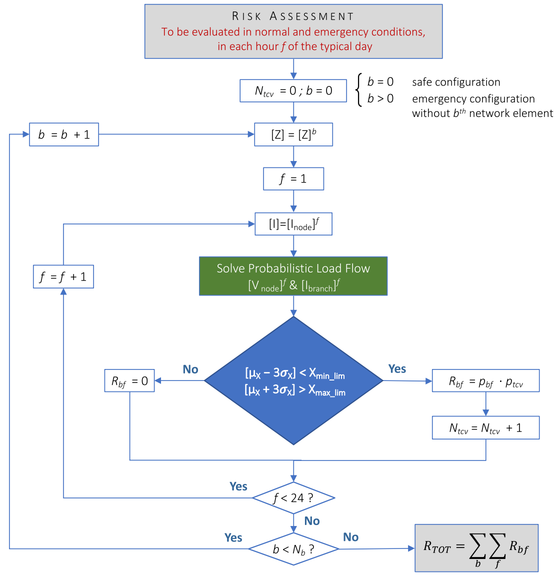

FIGURE 1. Identification of potential contingencies ($p_{tcv} > 0$) and total risk assessment flow chart.

linear combination of Normal random variables, the result of each PLF calculation is the Normal probability distributions of all the nodal voltages and line currents, through which the probability of not complying with the technical limits (p_{tcv}) can be assessed. By multiplying p_{tcv} and the occurrence probability of the relative operating condition, p_{bf} (the hour of the d^{th} typical daily profile when the b^{th} network configuration in the *N – 1* security analysis is in force), the corresponding risk component is determined (R_{bf}).

The probability p_{bf} is determined by simply multiplying the forced outage rate of the b^{th} network element and the occurrence probability of the specific customers' operating conditions (p_{fd}) because these two probabilities can be considered independent. The p_{fd} is the probability occurrence of the f^{th} hour on the d^{th} typical day in a year. Finally, the risk component R_{bf} is expressed in hours of violation per year:

$$R_{bf} = p_{bf} \cdot p_{tcv} \cdot 8760 \left[\frac{\text{hours}}{\text{year}} \right] \quad (1)$$

The sum of all the N_{tcv} risk components greater than zero gives the total risk of the network, R_{TOT}, that will be compared with the acceptable one, R_A, chosen by the planner. If $R_{TOT} > R_A$, planning options are implemented (FIGURE 2).

For each adverse event with a risk greater than the permissible value, both the DER active management and the network reinforcement (upgrade of existing conductors or transformers) tried to nullify the corresponding risk component, R_k, or minimize it with the available resources (residual risk $R_k^* < R_k$). Active Management (AM) influences only the risk component of the potential contingency because its application is activated only with those specific operating conditions. On the contrary, a network reinforcement solution can reduce the risk of many (or even all) events. Thus,

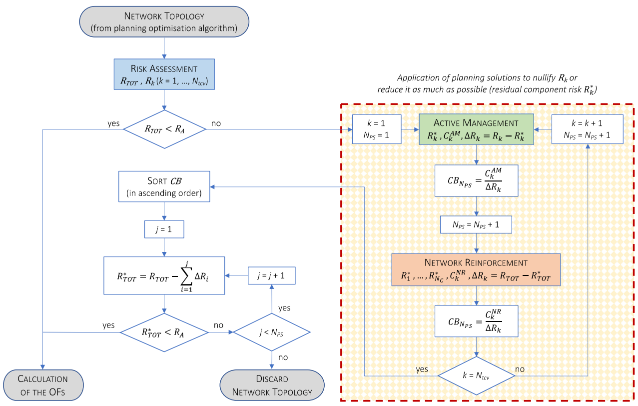

FIGURE 2. Identification of the best cost-effective planning solutions for the minimization of the total risk.

increasing network capacity can reduce network bottlenecks caused by diverse events. Consequently, all risk components must be updated for network planning solutions to estimate the overall network performance improvement. By associating the cost of implementation (C_k^{AM} or C_k^{NR}) with the risk reduction achieved (ΔR_k) with each option examined, the relative cost/benefit ratio (CB) is determined. When all the N_{PS} planning options have been examined, they are sorted in ascending order with the cost/benefit ratio, i.e., starting from the most effective. The procedure stops when the expected risk exceeds the maximum allowable risk (FIGURE 2). Alternatively, the process can be adapted to estimate the residual risk of a distribution network planning optimization when a maximum available budget is given.

V. CASE STUDY

The impact of flexibility from DERs has been analyzed on a large power distribution system (in Italy), characterized by several distributed RES plants (mainly photovoltaics), high electrification of final energy uses (higher than the national average) but a relatively low ratio between electricity demand and generation (many feeders manifest similar amount of consumption and production), and still young electric mobility.

The more significant part of the regional power distribution system is formed by rural overhead feeders, with overall extensions (sum of the lengths of all feeder's branches) ranging from 20 km to 90 km, a load density lower than 500 kVA/km^2, and generation from zero up to 8 MW. Urban feeders with buried and/or aerial cables, have lower extensions, higher load density, and similar existing generation.

A medium-term (2030) and a long-term (2050) planning horizon were considered for the study, coincident with the deadlines of the European climate targets. Some assumptions have been made in the first preliminary study:

- No new Primary or Secondary Substation will be added during the planning period. If the electric demand or the nominal power of new RES plants downstream a substation overcomes the existing transformer's rate, only the cost of an additional transformer is summed to network CAPEX.
- All customers are potential flexibility providers, 100 % of generation curtailment and 50 % of demand curtailment. Indeed, one of the goals is to estimate the needed flexibility to solve technical issues.
- The paper's analysis has been limited to the MV distribution system. The flexibility available in LV systems is assumed to be fully exploitable at the MV level.
- It is assumed that new wind generators are connected to the HV system, so they are not considered in the planning calculations.

A deeper investigation of the realistic flexibility exploitation from LV resources, as well as climate proofing of the new planning approach, are under execution and will be illustrated in the following publications.

A. ELECTRIFICATION SCENARIO

The increase in electricity load demand and production from RES derives from a previous study carried out at Regional and provincial bases to evaluate the potential to become a green model for the energy transition in the medium term thanks to the high electrification rate and the use of substantial renewable resources. The main assumptions are reported in the following.

1) DEMAND

Five driving factors are considered for the evaluation of the load demand growth rate:

- The growth rate follows the NECP [52] which foresees limited growth in the industrial sector and considerable growth (almost 2 % per year) in the commerce and services sector.
- Greater sensitivity of users to environmental issues so that purchase decisions are made not only based on the final cost but also on the impact of that purchase on the environment.
- Improved energy efficiency of household appliances, machinery, and heat production equipment.
- Reduced electricity prices due to greater penetration of renewable electricity generation equipment (favored by economies of scale and technological innovation) and the possibility of aggregation in local energy communities (particularly relevant for small communities).
- High technological innovation has led to the use of hydrogen and green fuels, i.e., renewable electricity.

Table 1 reports the growth rate for each sector compared to the reference years in 2030 and 2050.

Road transport, particularly EVs, is considered in the transport sector. In the reference year, in the Region, EVs are minimal (less than 0.01 % of the total number of cars). However, thanks (also) to a greater spread of charging stations [7] and the favorable costs of owning and operating the vehicle [5], the number of EVs in 2050 will be more than

TABLE 1. Load growth rate in 2030 and 2050.

Sector	2030	2050
Residential	+14 %	+37 %
Industrial	+7 %	+79 %
Tertiary	+14 %	+25 %
Agriculture	+6 %	+25 %
Transport	144%	930%

70 %. In the study, it is supposed the spread of three charging station technologies:

- Home charging stations (HCS), connected at the LV level, with a nominal power of up to 7.4 kW.
- Quick charging stations (QCS), public or private charging stations located in car parks at points of interest (e.g., ports, airports, trade fairs, shopping centers), but also in company car parks dedicated to the company's fleet of electric vehicles or employees' private ones. The nominal power of these charging stations is up to 22 kW, and they are connected at the MV level.
- Fast charging stations (FCS) are the public charging stations that are assumed to be located near refueling stations on main arterial roads (approximately every 50 km) and in urban settings. Their nominal power can be up to 50 kW and more, and they are connected at the MV level.

2) GENERATION

Concerning the production, it is estimated a mix of generation from renewable sources (wind, photovoltaic), and hydroelectric) capable of maximizing the Region's self-sufficiency (i.e., the ability to consume the energy produced locally), taking into account the temporal and spatial distribution of electricity load in 2030 and 2050, while satisfying technical constraints and ensuring an internal rate of return (IRR) greater or equal to 8 %, having a positive return of the initial investment at the end of the useful lifetime of installed renewable energy systems, according to the methodology proposed in [53].

Only onshore plants were considered for wind power generation, excluding offshore plants, due to their high cost and the long and complex approval process for offshore wind farm installation projects. Biomass and biogas plants are excluded from the analysis due to the high costs that this fuel is estimated to reach by 2050. Furthermore, the use of biogas was not considered due to its current low uptake of 2.5 % of electricity production from renewable sources by 2021 (0.1 TWh out of over 3.9 TWh) and a growth rate of 1 % over the last ten years.

Table 2 shows the expected wind and photovoltaic capacity growth in 2030 and 2050 in terms of the percentage of installed power at the beginning of the planning period (2023).

3) GEOSPATIAL LOAD FORECAST

Given the regional scale demand, production, and transport growth scenarios (as described in the previous sections), a spatial downscaling from national plans to secondary substations (SS) was carried out through SS electrical and spatial characterization. Except for the demand, the data of which were available from the DSO, the downscaling process started from publicly available open data about the territory and the socio-economic situation (e.g., national data on the number of types of buildings at the municipal level, number of cars per municipality, etc.) and georeferenced information. The first step of the downscaling process is dividing the territory through a geometric procedure (Thiessen Polygon method [54]) into elementary portions that represent the area of influence of each SS. Then, the characterization of the elementary portions in terms of demand shares, installed power generation, and transport at year-zero (through incidence matrices between the elementary portion and administrative boundaries, land usages, buildings, commercial and industrial activities, etc.) is performed (FIGURE 3).

TABLE 2. Generation growth rate in 2030 and 2050.

	2030	2050
Wind expected capacity [%]	8%	112%
PV expected capacity [%]	471%	658%

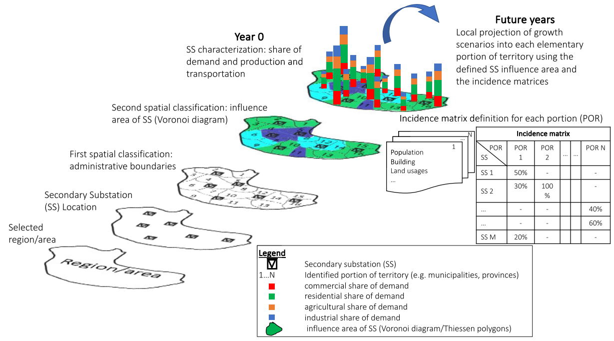

FIGURE 3. Spatial downscaling process.

In particular, a bottom-up approach is carried out for the load demand, divided into user categories (i.e., residential, tertiary, industrial, and agricultural). Considering the specific shares of residential, agricultural, industrial, and commercial consumption within the same SS and applying to them the provincial demand growth rates differentiated by user category, the demand growth rate of each SS is obtained.

On the other hand, due to the lack of data concerning the production quotas attributable to each SS and the location of the HCSs, FCSs, and QCSs a top-down approach was developed from known data on a regional or provincial basis, taking into account the land cover (i.e., physical characteristics of the Earth's surface as observed from above, including forests, water bodies, urban areas, etc.) and land usage (human activities and functions that occur on the land).

For estimating the installed power at year-zero, the annual production data were translated into installed capacity by using provincial average production in kWh/year·kWp. Then, the territory pertinent to each SS is analyzed to identify the areas where it could be possible to locate new generators. The expected generation is associated with the SS of the area eligible to integrate the new generation.

Finally, the locations of the expected HCS, FCS, and QCS have been estimated according to the number of EVs envisaged in the scenarios and the characteristics of EV owners (e.g., the possibility of installing a home charging station considering the type of home, mutual distances between charging stations, etc.) [41], [42].

VI. RESULTS AND DISCUSSION

The study involved 43 primary substations, which supply around 400 MV feeders (total length 8,129 km), and 7,700 secondary substations. The MV network topology is weakly meshed but radially operated. Almost all the feeders have one or more emergency ties (ordinarily open) that can be used to resupply them in case of network outages from adjacent feeders.

Customers' behavior throughout the year has been modeled through 36 daily curves (working day, Saturday, and Sunday for each month), discretized with a one-hour step. These profiles have been derived from DSO's measurements (for all MV users and LV customers with a nominal power more significant than 55 kW) or standard profiles differentiated by sector (residential, tertiary, etc.).

Photovoltaic generators have been represented with 12 daily curves, one for each month, depending on Regional solar irradiation levels.

The authors have developed two suitable Monte Carlo simulation procedures for the charging stations' demand profiles, one specific for HCS [55] and the other for FCS and QCS [56]. Through random choices, the probabilistic daily charging profiles are estimated by pondering various features, like driving distances, car characteristics (battery capacity and average consumption), charging rate, and drivers' driving habits. FCS and QCS are also related to the area covered by the charging station and, consequently, the number of cars served. Every profile has been characterized by uncertainty modeled as a Gaussian stochastic variable. This representation is valid for modeling the load behavior, and it is generally accepted in planning studies for renewables, even if this approximation can become less founded when the DG penetration is high. The planning tool described in the previous sections has been used assuming the set-up summarized in Table 3.

Optimizations are guided by the overall system cost, the sum of the Net Present Value of capital expenditures (CAPEX), and the operating costs represented by Joule losses and flexibility procurement (OPEX). In the supposed flexibility market, the DSO purchases flexibility products through market auctions for capacity (availability to provide the product) and energy (provision of the product). The average of national markets clearing prices was used to monetize the Joule losses.

TABLE 3. Main parameters for the planning studies.

Technical Constraints		
Operating Conditions	*Type of violation*	*Admissible limits*
ordinary	voltage variation	± 5 %
	line overload	none
emergency	voltage variation	± 5 %
	line overload	+ 5 %

Risk Analysis	
Maximum Acceptable Risk (R_A)	5 hours/year

A. HOSTING CAPACITY AND FLEXIBILITY

The definition and the assessment of *hosting capacity* attracted a vast number of researchers. The current scientific literature offers different definitions of *hosting capacity* and methodologies to assess it fairly and reliably. In this way, the definition of hosting capacity used is one of the first proposed. The hosting capacity (HC) of the network is the maximum capacity of demand and generation that it can accept without upgrades, whereas all technical limits are respected. Even if the definition used is intuitive, how the network capacity is calculated directly affects the results.

The hosting capacity of the network can be increased without upgrading the network if the operation of DER is included as an option available to DSO at the cost of flexibility procurement. The cost of the flexibility procurement depends on the amount of services (capacity) and the duration of services possibly used (energy). Whether flexibility is used to solve contingencies caused by post-fault reconfigurations (low probability events) or by temporary mismatches between demand and local generation (a few hours per year) caused by new connections or increased electrification, the procurement can be a good option not to slow down the integration of green generation while development plans are executed. Therefore, the cost of flexibility procurement is generally limited by the low probability of critical events occurrence. If a network issue happens systematically for a significant number of hours, procuring external services can be so expensive to make using flexibility unattractive. It is immediately evident that a methodology for a correct assessment of the hosting capacity that includes the use of flexibility cannot disregard the probability of contingencies (e.g., the expected number of hours per year of overgeneration). Probabilistic planning is necessary to estimate the probability of occurrence of each operating condition. Indeed, the deterministic calculation dramatically reduces the hosting capacity, assuming "certain" the worst events, even if extremely rare, and looking for zero risk. The immediate consequence of this hyper-conservative approach is that new DER connections must wait for the revamping of existing lines or the building of new ones without a real reason. The resort to flexibility if the calculation of needs is still deterministic cannot change the situation. Indeed, the deterministic calculation overestimating the demand for flexibility for increasing the hosting

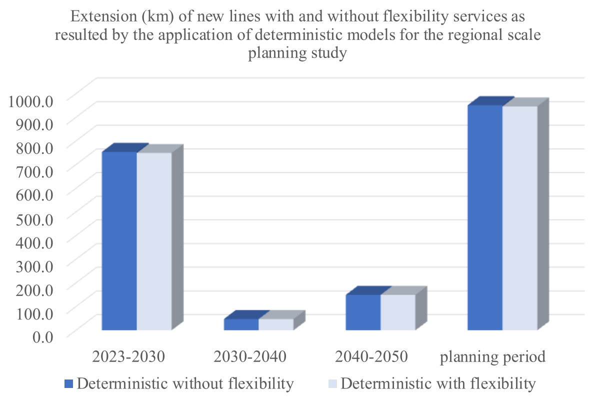

FIGURE 4. To face the expected growth of demand and generation, the kilometers of new or renovated lines are almost the same (maximum variation 0.6 %) with or without flexibility if deterministic models are used. The deterministic model is not suitable for capturing the worth of flexibility to increase the hosting capacity.

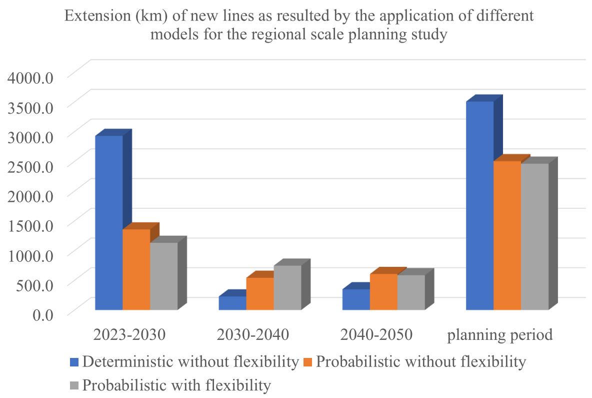

FIGURE 5. Comparison among different methodologies for assessing the hosting capacity.

capacity makes the procurement of services too expensive and non-convenient with respect to infrastructural actions. Using probabilistic models is crucial to highlight the benefits of flexibility when network issues are temporary and low-probability events. In this case, flexibility can be used to postpone investments without keeping the network under an uncontrolled risk of not respecting technical limits.

The results in FIGURE 4 show the application of the deterministic approach, without and with flexibility, to a set of feeders (i.e., 10 % of the total). Such results confirm such an important consideration. The deterministic approach gives a low hosting capacity level from the beginning of the planning period when demand and generation started increasing. The deterministic hosting assessment also hides the benefits of flexibility because of the high expected costs. Thus, the acceptance of new loads and generators passes through an immediate reinforcement of the network that is not created by real problems but by a conservative approach that was reasonable in the past but unsuitable with the expected dynamics and the need to achieve the electrification goals.

FIGURE 5 shows that if the calculation of hosting capacity is made with a probabilistic approach aimed at keeping the

TABLE 4. Hosting capacity assessment (in terms of line length that needs revamping).

	2023-30	2030-40	2040-50	Global
Deterministic	2,927.8 km	228.3 km	349.3 km	**3,505.4 km**
Probabilistic Without Flexibility	1,355.2 km	541.9 km	605.4 km	**2,502.5 km**
Variation	-53.7%	+137.4%	+73.3%	**-28.6%**
Probabilistic With Flexibility	1,129.8 km	745.8 km	584.7 km	**2,460.3 km**
Variation	-61.4%	+226.7%	-67.4%	**-29.8%**

risk of limit violations under a predefined level, investments can be postponed even without using flexibility. Such change in both approach and methodology simply allows the connection of new DERs and new loads, keeping the risk under control with an engineering approach. The worth of flexibility depends on the acceptable risk of limit violation. A lower value of R_A undoubtedly makes the use of flexibility more convenient. Indeed, by reducing R_A,the number of critical events with low occurrence probabilities increases. Since these events have low occurrence probabilities, flexibility services that resort to seldom-used flexibility options become increasingly attractive.

In conclusion, it is evident that if a DSO must facilitate the integration of DER, the calculation of hosting capacity is crucial. The deterministic calculation used so far gives the DSO clear results and high confidence but causes possible connection delays. Without losing confidence in quality and controlling the risk, a more detailed probabilistic approach can give a realistic idea of hosting capacity. The value of flexibility in increasing the hosting capacity cannot be assessed without a probabilistic approach.

B. RESULTS

The first research finding is that the energy transition will inevitably require massive infrastructural investments. The energy transition is not the only reason for investments since climate change adaptation and quality targets will also contribute to expenditures. However, the increase in demand for electrification and the connection of DG have a great impact [18]. Considering a very challenging scenario and that the geographical localization of the connections depends on market strategy and does not take into account the HC of the existing network, using the most conservative approach to calculate the HC, almost 43 % of MV lines need revamping in the time period 2023-2050; 36 % of network upgrades should be necessary in 2023-2030 (Table 4).

A modern approach to planning allows the planning engineer to deal with network criticalities proportionally to their entity without seeking an ideal zero-risk option. Indeed, this study shows that if the probability that a new DG causes network issues is duly considered, its connection can be considered acceptable without immediate network upgrades in more cases, particularly in the first years of the planning period. By accepting a reasonable annual risk, only 17 % of lines must be revamped in 2023-30 (83 % of lines have

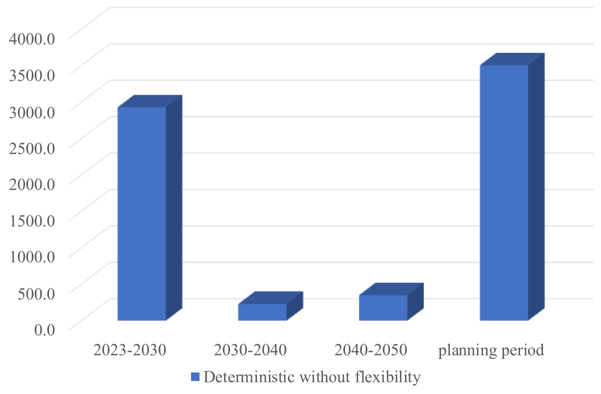

FIGURE 6. **The kilometers of lines need revamping if deterministic models are used. HC is immediately not enough.**

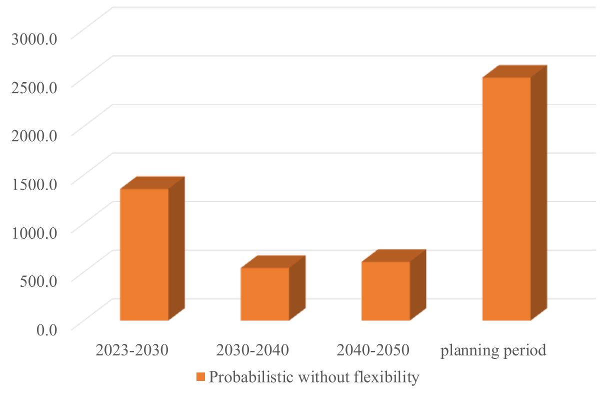

FIGURE 7. **The kilometers of lines need revamping if probabilistic models are used without resorting to flexible products. Probabilistic models allow a more realistic HC evaluation.**

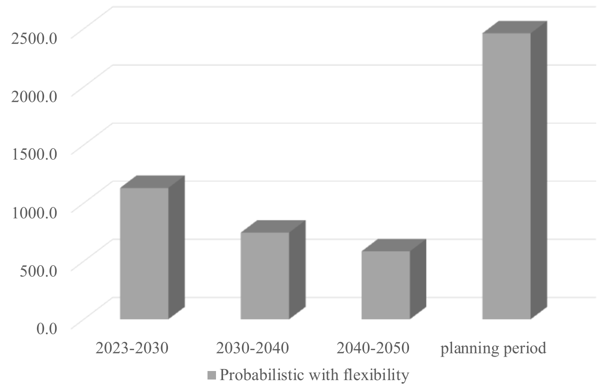

FIGURE 8. **The kilometers of lines need revamping if probabilistic models are used with the resort to flexibility products. Flexibility can artificially increase the HC by a few percentage points.**

enough HC). This is to say that the assessment of the hosting capacity is dependent on the calculation techniques, and with a more reasonable approach, a large amount of RES can be connected without any infrastructural action in the first years. The increase in hosting capacity obtained by using an appropriate assessment methodology is twofold. Firstly, the DSO can be a true energy transition facilitator, enabling more DG connections and keeping the risk of quality controlled. Secondly, the DSO can plan network reinforcement by following optimal long-term strategies without adopting non-optimal actions to allow for the fast connection of new producers or big consumers. To make this possible, the planner engineer must trust probabilistic models that allow a more realistic assessment of the real impact of the energy transition.

The results demonstrate that the existing networks have enough hosting capacity to face the first wave of energy transition impact (2023-2030). If the HC, as calculated with a probabilistic methodology, is the natural network HC, using flexibility from local markets is the way to further increase it, graduating in time the resort to infrastructural actions. With flexibility markets, the HC can be further increased by 3 % (14 % of lines need revamping).

Looking ahead in time, the conservative HC calculation anticipates most investments in the first years. From Table 4 after the first wave of investments, 97 % of lines have enough HC to face the energy transition in 2030-40 and 96% in 2030-50. Using a less conservative approach capable of explicitly considering the risk without the flexibility, the HC is around 93 % in 2030-40 and 93 % in 2040-50. It is interesting that the probabilistic approach allows postponing 2050 investments. During the planning period, 43 % of the lines must be revamped following a deterministic approach (57 % have enough HC). With the probabilistic model, the risk can be kept under the allowable level by renovating 31 % of lines (69 % have enough HC). Flexibility gives small ameliorations in the long term, with around 1 % fewer renovations compared with probabilistic.

FIGURE 5 to FIGURE 8 clearly shows the benefit of a flexible approach to planning. With the current approach, which is very conservative, network actions are immediately necessary (2023-2030). With a modern approach, investments can be moved to the future, minimizing the possible planning regret in case the future will be significantly different. In the real life of a DSO, using a modern approach, the DSO can design a long-term plan to consider reliability and resilience targets and start implementing it by anticipating crucial actions. The timing of actions will not affect the energy transition because all the not revamped network portions can, in most cases, accept the transition challenges with appropriate use of the flexibility that keeps risks below the acceptable threshold.

The expected costs are largely influenced by the models adopted. It was decided not to consider the benefit of anticipating investments to minimize the risk of high regrets caused by long-term uncertainty. Anyway, the deterministic model that considers inadequate assets very soon causes the anticipation of investments with the risk of regrets in case of different futures. Thus, one consequence of anticipating investments can be easily argued as less need for flexibility to increase the HC.

Regarding CAPEX, it could be argued from data analysis that there should be a reduction of close to 50 %, with or

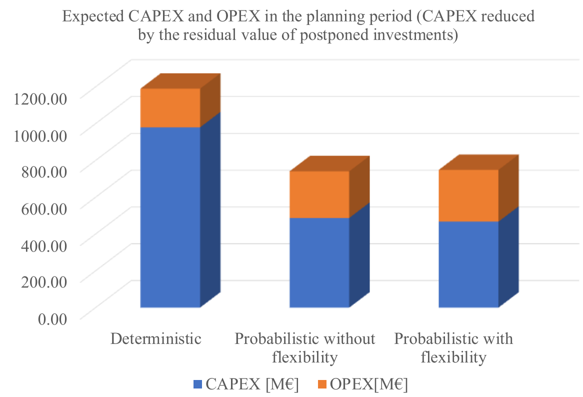

FIGURE 9. CAPEX and OPEX caused by the electrification of final uses of energy and connection of RES in 2023-2050.

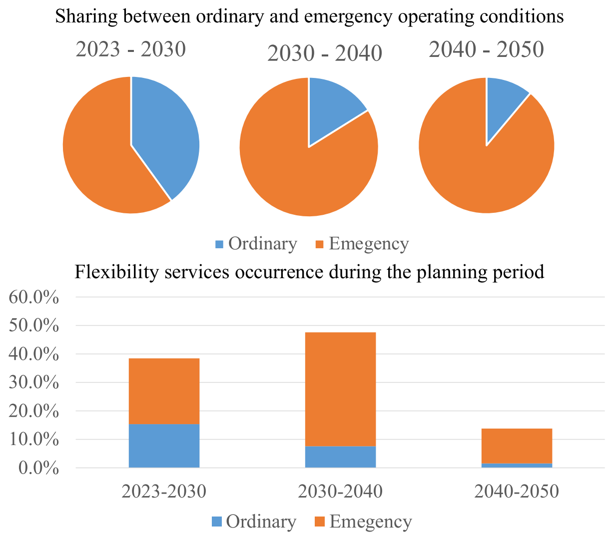

FIGURE 10. Analysis of flexibility services usage.

without flexibility (FIGURE 9). This does not mean halved network investments in 2023-2050, thanks to the combination of probabilistic calculations and flexibility usage. The new models simply allow for postponing and optimizing investments. The residual value of new assets at the end of the planning windows is high and discounted from the expenditures for network reinforcement reduces the final CAPEX. The DSO's financial effort is proportional to the reduction of the network upgrades, which is around 30 %. This does not mean the number of infrastructural investments will decrease if flexibility and probabilistic calculation are adopted. The stress caused by energy transition can be faced only with network reinforcement and network expansion, which are very similar in quantity independently from the planning stage. The models impact the timing of investments and risk management. Even the 30 % fewer new lines that can be saved will be necessary after 2050. The number of network assets that must be revamped or substituted is not affected by flexibility in the long term. Flexibility and realistic hosting capacity calculations allow for the immediate acceptance of more RES while the long-term investments are planned and realized following appropriate scheduling and avoiding managing too many simultaneous work-in-progress areas in cities and villages.

OPEX increases with a non-deterministic approach to planning around 33 % (FIGURE 9). Modern planning tries to exploit existing assets close to the maximum limit, increasing energy losses that are responsible for the increase in OPEX. Whether flexibility is used, OPEX further increases the need to pay for the services customers offer.

C. FEATURES OF FLEXIBILITY

DSOs request a better knowledge of flexibility features for full acceptance since applying flexibility services is a new practice at the distribution level. The extensive application of a modern planning tool in a virtuous circle, will allow for deriving statistics on flexibility usage and providing preliminary answers to the main open questions related to flexibility. The first relevant question for DSOs is about timing, i.e., *when are flexibility services necessary to maximize hosting capacity?* FIGURE 10 shows the sharing of the overall amount of flexibility services applied in the whole set of distribution feeders examined. In the first years of the planning period, almost 40 % of flexibility services are requested during ordinary operating conditions. In the following years, with the implementation of network upgrades, this occurrence drastically dropped, making flexibility usage more and more assigned for solving critical operating conditions during emergency configurations that originated after a fault in the system. Most of the flexibility is used up to 2040, while in the last ten years, its application becomes more occasional and less critical due to the network upgrades deferred in the previous years of the planning period. Occurrence matrixes have been built to understand the yearly and daily usage of the flexibility services by dividing the whole year into quarters (Q1 – winter, Q2 – spring, Q3 – summer, Q4 – autumn) and the day in four intervals of six hours (T1 – from midnight to 6 am, T2 – from 6 am to noon, T3 from noon to 6 pm, T4 from 6 pm to midnight). Then, the height of the histograms highlights the intervals when the flexibility services are more likely to be requested (FIGURE 11).

The request for flexibility services is prevalent in the daytime during the sunniest periods due to a surplus of photovoltaic generation that may cause overvoltage and overload and during the winter peak hours due to the high demand that can cause excessive voltage drops or overload. A particular request for flexibility appears in the first hours of the night (interval T1) due to the coincident demand from the HCS (this demand correlation increases as the planning time advances). These results can help DSOs decide when to activate auctions or other mechanisms to procure flexibility services.

The second important question for the DSO is about quantity and quality, i.e., how much flexibility has to be procured and with which characteristics. More specifically,

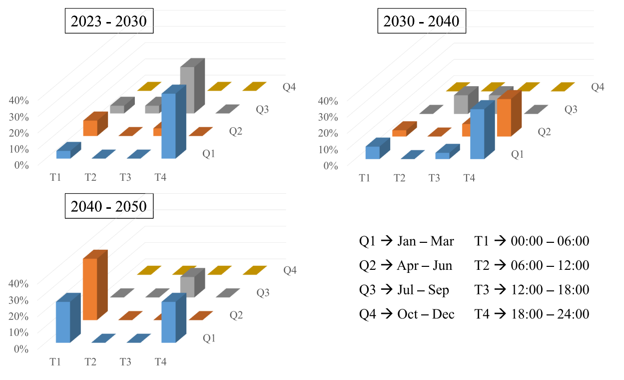

FIGURE 11. **Yearly and daily usage of flexibility services.**

how much power variation is required? And, *for how many hours per year should such flexibility be available?* The evaluation of the service magnitude has been distinguished between regulation-up and regulation-down, with the intention of the first one being an increment of power production or a decrease of power absorption and vice versa for the second. The maximum amount of active power variation has never overcome the 300 kW in up and the 275 kW in down, meaning that the expected service magnitude required to correctly operate the distribution system is relatively small. Therefore, for the local needs of a DSO, the flexibility market should be open to most electric distribution customers and not limited to a few extensive facilities (like $\geq$ 1 MW). Regarding the duration of the availability of flexibility services, the maximum values have been achieved in the first years of the planning period (2023-2030), never exceeding 200 hours/year. The average duration during the planning period is 100 hours/year.

VII. CONCLUSION

The energy transition will substantially impact the power distribution systems requiring high investments. Planning procedures DSOs generally adopt are based on the traditional worst-case deterministic approach. The evolution towards probabilistic models, together with flexibility services from DERs and demand-side management, are valuable for optimizing and postponing some network upgrades. In this frame, the correct estimation of the flexibility positive contribution to distribution network planning deserves particularly robust new planning tools based on probabilistic calculation and risk assessment. Indeed, they allow quantifying when, where, and how much flexibility is required, promoting the activation of local flexibility markets. Moreover, they will allow the correct estimation of flexibility value, considering each critical event's occurrence probabilities superseding. Indeed, if flexibility is assessed with traditional deterministic calculations, flexibility value is negligible. Finally, it should be noted that these new planning procedures require advanced load and generation forecasts with high spatial detail. The better the prediction, the smaller the risk in planning related not only to uncertainty in the generation and consumption of energy but to the real participation of DERs in local flexibility markets that are strongly related to a reliable forecast of the energy transition path.

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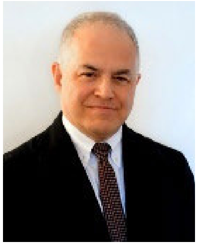

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