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Risk-oriented planning for flexibility-based distribution system development

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A B S T R A C T

The paper presents a risk-based distribution network planning procedure to perform a comparison (in terms of costs and associated residual risks) among conventional planning solutions and the exploitation of flexibility purchased from distributed energy resources through bilateral contracts or local markets. The procedure has been integrated within software developed by the Authors in the past decades for distribution network expansion planning. The software already includes many of the main distinctive characteristics for a modern planning tool, such as abandoning the traditional worst-case approach, resorting to non-network planning options, and implementing the stochastic network assessment to consider generation and demand uncertainties. Since many flexibility resources are connected to the low voltage system, both medium voltage and low voltage networks have to be jointly analysed to account for their mutual interactions. The planning process has been applied to distribution networks representative of the Italian distribution system. The low voltage system has been represented by replicating few real networks provided by the leading Italian Distribution System Operator. Consumption and generation patterns have been modelled from real anonymised measurements.

1. Introduction

Modern trends in power systems have changed the way distribution systems are planned and designed. The worldwide impulse to the integration of a massive amount of Renewable Energy Sources (RES) for carbon neutrality [1–3], supported by new technologies (e.g., Energy Storage Systems (ESS), fast communication, bidirectional smart meters, etc.) are making flexibility not only a need but also a real opportunity to be explored in distribution system planning and operation. Particularly if high power — highly coincident demand (e.g., electric vehicles (EV) charging stations, heat pumps, induction cooking) and RES have to be accommodated on the system. Unfortunately, the distribution system was designed with minimum observability and controllability, privileging economy and simplicity with almost no power generation connected. Thus, due to the increasing share of non-programmable generation from RES, Distribution System Operators (DSOs) are experiencing and facing issues caused by network exploitation non-coherent with the original design assumption (e.g., excessive voltage rises, sudden voltage variations, power congestions, reverse power flow on primary and secondary substation transformers, etc.).

International scientific organisations agree on the need for a new approach and new assumptions in distribution development, which can no longer be based on deterministic distribution planning for economical and quality reasons. Indeed, the most used deterministic *fit & forget* strategy aims to design a distribution network against the most critical operating conditions (even if extremely rare). The strict application of this planning philosophy with the intermitting, non-programmable RES, often non-homothetic with the demand, can induce the renovation of almost all the existing distribution networks, causing an unsustainable amount of network investments [4]. To change the planning paradigm and fairly compare the grid upgrades with the potential support from flexible demand and generation, new methodologies based on probabilistic or robust optimisation techniques are necessary.

By now, the literature is becoming to be richly populated with algorithms and methodologies to modernise distribution planning using Active Management (AM) of the distribution system based on the flexibility offered by consumers, producers and those that do both (prosumers) (e.g., [5–13]). The uncertainties of RES generation, demand and the available flexibility have been considered under different demand forecasting scenarios in the long-term planning (e.g., in [6]), while the robust optimisation is still not so extensively proposed, even if examples of application are increasing in the most recent literature [14,15].

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List of symbols

R_A	acceptable risk of violation
R_{TOT}	overall risk characterising a specific distribution system
EC	existing configuration
SC	starting configuration
OF_{SC}	objective function evaluated in the starting configuration
BC	best configuration
OF_{best}	objective function evaluated in the best configuration
NC	new configuration
OF_{NC}	objective function evaluated in the new configuration
CC	current configuration
OF_{CC}	objective function evaluated in the current configuration
C_N	network cost
C_F	flexibility cost
C_L	cost of Joule energy losses
C_{ENS}	cost of energy not supplied
X	generic Normal deviate (it can represent the nodal voltage V or the branch current I)
μ_X, σ_X	mean value and standard deviation of X
X_{max_lim}, X_{min_lim}	maximum and minimum limits of X
Z	shifting variable used to convert X to the "standard" normal distribution ($\mu = 0, \sigma = 1$).
Z_{max_lim}, Z_{min_lim}	maximum and minimum limits of Z
$P\ (Z > Z_{max--min\_lim})$	probability that Z exceeds its limits
Φ	cumulative distribution function of the standard Normal distribution
N_b	number of the network branches
p_{bf}	occurrence probability of the bth network configuration during the fth hour
p_{tcv}	probability of technical constraint violation
R_{bf}	risk associated with the bth network configuration during the fth hour
N_{tcv}	number of configurations with p_{tcv}>0
FOR_b	forced outage rate of the bth network element
$MTTR_b$, τ_b	Mean Time To Repair of the bth network element
$MTTF_b$	Mean Time To Failure of the bth network element
p_{fd}	occurrence probability of the specific customers' operating conditions in the fth hour of the dth typical day
nh_{fd}	yearly number of occurrences of the fth hour of the dth typical day
λ_b	fault rate for overhead line and buried cables [faults/(year·km)]
[Z], $[Z]^b$	impedance matrix for the bth network configuration
[I], $[I_{node}]^f$	nodal current matrix during the fth hour
$[V_{node}]^f$	nodal voltage matrix during the fth hour
$[I_{branch}]^f$	branch current matrix during the fth hour
V_{lim_min}	minimum voltage limit
V_{lim_max}	maximum voltage limit
I_{lim_max}	maximum branch current limit
N_{PS}	number of planning solutions
R_k	risk of the kth configuration (without planning solutions implemented)
R_k^*	residual risk of the kth configuration (with planning solutions implemented)
$\Delta R_{i,}$ ΔR_k	risk reduction achieved
C_k^{AM}	cost of the non-network solution (active management)
$CB_{N_{PS}}$	cost/benefit ratio
C_k^{NR}	cost of the network solution (network reinforcement)

Nevertheless, the uncertainty in the current distribution system requires the quantitative assessment of the risk associated with any planning decision. The acceptance of trivial risks often corresponds to significant savings, and, for this reason, it would be unreasonable to not consider them in the development plan of the distribution system [4]. For these reasons, some papers consider a risk component in their planning model [8,9,11], but only a few deal with the assessment of the risk inherent in exploiting non-network or non-infrastructural solutions in combination with the traditional network development [10,12,13]. In [8] the probability of contingencies is considered only for the reliability calculation: the cost of energy not served, added to the objective function, has been assessed by weighting the power curtailment with such probability of contingencies. In [9] the risk of overcoming the technical constraints is transformed into an economic risk through a risk indicator used in financial research, but the planning problem is dedicated only to the feeder routing and not to evaluate non-network solutions. A risk indicator is also used in [11] for determining the optimal size and site of DER units with optimal allocation of section switches in a multi-microgrid system, but the flexibility offered by the DERs are not compared with the network reinforcement as a planning alternative. In [10] the traditional network development approach (i.e., without resorting the DER flexibility) vs an innovative approach that uses DERs' flexibility for solving the technical problems are compared, but the risk of exceeding the technical constraints is explicitly assessed a posteriori for the obtained optimal reinforcement plans, and it is not considered within the optimisation. In Paper [12] at each year of the planning horizon, the risk of overcoming the network capacity due to the growth of loads, to find the optimal level demand at which the network should be upgraded using traditional network solutions (i.e., reinforcement the existing assets or building newlines) or procuring temporary non-network solutions is calculated. However, the procedure in [12] considers only a lumped model for the analysed non-network solutions, and they are not simultaneously optimised (i.e., firstly, the peak shaving is used as a Demand Response (DR) option, and then the temporary uses of ESS or Distributed Generation (DG) are considered). In [13] a Healthy Index (HI) - based planning procedure is proposed for considering both network and non-network planning options. The HI is used for characterising with a single value an asset condition and for including the cost of reliability risk and the cost of greenness risk (i.e., the cost of DERs for supporting the distribution network operation) in the objective function, but the technical limits are not checked in term of risk. In addition, to our best knowledge, none of the proposed approaches properly assess the risk in terms of both the probabilities of the critical event occurrence and of the damage appearance following the critical event. In this context, the adverse event can be one of the operating configurations that have to be considered in the distribution network planning (e.g., normal and the N-1 emergency conditions), and the damage is the technical limit violation (i.e., cable rating overcoming or voltage constraint violations).

The paper contributes to this field with a new model that allows verifying the risk of technical constraint violations with the relative confidence (risk of violation acceptability) by considering both the probabilities (i.e., the critical configuration occurrence) and the harmful effect appearance. If the overall risk associated with one specific network architecture is not acceptable, then planning alternatives have to be put in place to reduce such risk. Thus, the risk assessment guides the planning process with proper consideration of all uncertainties.

An additional complication for establishing a modern electric distribution system planning procedure is represented by the growing need to integrate both the low voltage (LV) and medium voltage (MV) systems into the same optimisation. Indeed, since DERs are present in all distribution levels, when planning the MV distribution network, also the underlying LV systems should be considered since they can be significant sources of flexibility by aggregating the small resources dispersed at that voltage level [7,10]. The LV networks host a rapidly increasing number of small Photovoltaic (PV) plants with and without batteries, a plethora of customers qualified to potentially participate in DR programs and a growing number of slow EV charging points. Very few papers propose the LV networks as flexibility providers for the upstream system operation, and they often model LV with equivalent representations based on the aggregation of DG and demand, disregarding the limitations of the LV networks [6,7,10]. However, at the LV level, due to its configuration (i.e., usually radial networks fed by transformers equipped with off-load tap changer serving several imbalanced single-phase loads), voltage regulation and power congestion can arise. For these reasons, it is evident that a portion of the LV DER flexibility should be used in the LV system, and only the residual flexibility might be available for upper levels (i.e., MV distribution). An integrated approach to assess the flexibility not essential to the LV is then necessary. In the scientific literature, different approaches have been proposed [4]: (i) simultaneous analysis of a detailed representation of both systems (excessive computational burden drawback); (ii) simplified representation of LV network within the MV model, containing [16] or not [6,10] information for estimating LV maximum stress (voltage drops, overvoltages, overcurrents); (iii) sequential optimisation of LV and MV networks, by integrating the synthetic results of the LV system analysis into the MV system model. The latter approach has been used in the paper. The same approach is proposed in [10], where the flexibility providers' requirements regarding the flexibility utilisation restrictions are optimised, but the LV network technical constraints are not considered.

Finally, modern planning system tools should also consider flexibility procurement. Flexibility products can be exchanged among system operators and flexibility providers (i.e., the ensemble of RES, active demand, stationary of mobile electricity storage directly connected to the distribution system) using different forms (e.g., connection agreement, network tariffs and market) [17]. Market-based procurement is recognised as the most suitable option since the procurement of flexibility on a competitive basis can ensure lower costs compared to alternative solutions [17]. Currently, a distinction has been made between global markets that solve the needs of both Transmission and Distribution System Operator (TSO and DSO) from local markets dedicated exclusively to DSO problems. Suitably aggregated, DERs can offer flexibility in the Ancillary Services Market (ASM) and help the TSO procure the required reserve capacity and provide real-time balancing services. From the DSO point of view, this scenario (based only on a global market) can introduce new challenges in their distribution systems, which entails adequate TSO–DSO coordination. However, in this case also, the exploitation of flexibility on DERs represents for the DSO an opportunity to explore as an alternative to the conventional network reinforcement. Indeed, the new European energy directives boost DSO to acquire "*non-frequency ancillary services needed for its system through transparent, non-discriminatory and market-based procedures*" and sets the commitment for DSOs to explicitly consider flexibility from DER in their distribution system expansion plans [18,19].

Several demonstration projects have been funded to validate the technologies available for the use of flexibility and the interaction among stakeholders in the market and assess their impact on the management and planning of the distribution network. These projects analyse different levels (urban areas [20], regional [21], national and cross-border level [22,23]), different aspects like flexibility market [20,21], TSO–DSO interaction schemes [24], involving different stakeholders (e.g., system operators, aggregators, technology providers). In most of them, the proposed technology's profitability is tested through pilot sites in different countries [20–24]. On the contrary, few examples of testing experiences have been proposed worldwide through regulatory sandboxes in the existing system [25]. Currently, the Italian Regulatory Authority (ARERA) issued a resolution (Resolution No. 352/2021/R/eel) [26] which defines the next regulatory steps for a new dispatching framework by 2022.

The paper proposes a methodology that perfectly fits this context, presenting research results of a recent research activity whose researchers pioneered modern planning methodologies for active distribution systems in light of these considerations [27–31]. The primary research outcome is assessing new planning strategies, which incorporate the flexibility services acquisition from customers as a planning option. Particular attention has been paid to obtain a fair comparison between the network and non-network planning solutions by explicitly considering the value of the risk associated with each choice. Moreover, since a large amount of DER is connected to LV networks, where they cause most technical issues, both MV and LV systems have been considered in the definition of the optimal design. Finally, two possible flexibility product procurements (i.e., the local market and the bilateral contracts) are considered and compared.

The main contributions of this paper are:

- the integration of operation in planning by resorting to the flexibility of DERs as non-network planning options to be compared with the more traditional network reinforcement. This implies, among other things, the probabilistic approach for managing the uncertainties of RES production and demand,
- the ability to treat the risk of technical constraints' violation, calculated by considering both the probability of exceeding the grid limitations of each planning option together with the occurrence of the network configurations, and comparing its value with an acceptable risk level,
- the LV networks' involvement in the provision of flexibility products both for solving operating issues in the LV distribution system and, in turn, for offering the residual flexibility to the upper voltage level network, and

- the attention to the way of the flexibility procurement, evaluating the DER market participation and the bilateral contracts between DERs and DSO.

The paper is organised as follows: in Section 2, the pillars of modern distribution planning are described. Then, in Section 3, the risk-oriented planning approach is proposed. In Section 4, the integration of the LV network in the MV planning is presented. The application of the new planning tool to a real portion of the Italian distribution system is proposed in Section 5, and different planning strategies are compared in terms of costs and residual risk. Final remarks conclude the paper.

2. Distribution planning when flexibility competes with grids

The extension of distribution networks and their local impact on the power system, the high cost of communication in areas not always served with the necessary quality of services, the cost of devices, and the almost exclusive presence of passive loads, as well as the role assigned to DSOs by National Regulations, are some of the most significant reasons that had limited the real-time operation of networks and energy resources until the first decade of the current century. The distribution network has been planned and designed robust enough to avoid operation by adopting the conservative deterministic criterion known as *fit & forget* [4]. Distribution automation was largely used for automatising the operation of primary substations and network reconfiguration for fault location and service restoration.

The energy transition is transforming the distribution system fostering the full implementation of smart grid concepts [19]. The distribution system has been modernised. High-quality communication infrastructures are now in place to reach distributed resources; the internet allows connecting any small customer through advanced metering infrastructures and dedicated gateways; local markets for flexibility have been already used in several pilot projects. Thus, a new planning process should capture technical, regulatory and market opportunities to accomplish the development sustainability goals.

Planning the evolution of the distribution system must embrace the new trends and consider flexibility to fix temporary problems caused by the intermittency of RES or post-fault network reconfigurations [7]. The significant uncertainty related to the flexibility provision, besides the intrinsic stochastic behaviour of demand and the renewable generation, require the abandonment of determinist calculation – ideally oriented to neglect the risk of any technical issue – in lieu of a more realistic risk-oriented approach to find a compromise between technical requirements and budget restrictions. Risk assessment is a crucial part of a planning process that compares traditional network options with non-network actions [9,10], which can also be applied in the optimal planning of modern network configuration like networked microgrids [11]. Finally, the presence of different players with different goals that can interact within the same system suggests the application of a Multi-Objective programming approach for finding an optimal compromise for the planning solution [4].

Fig. 1 shows the structure of a planning process suitable to be used in the context of modern distribution planning, whose key points are:

1. *Customer's time representation*. The snapshot of a single operating condition, as for the traditional analysis of the worst-case scenario, is unsuitable for investigating the effectiveness of planning options based on the flexibility from DER. Indeed, the optimal operation of stationary and mobile storage devices and the active management of demand and generation are characterised by intertemporal correlations that can be captured only by adopting suitable time series in planning studies.

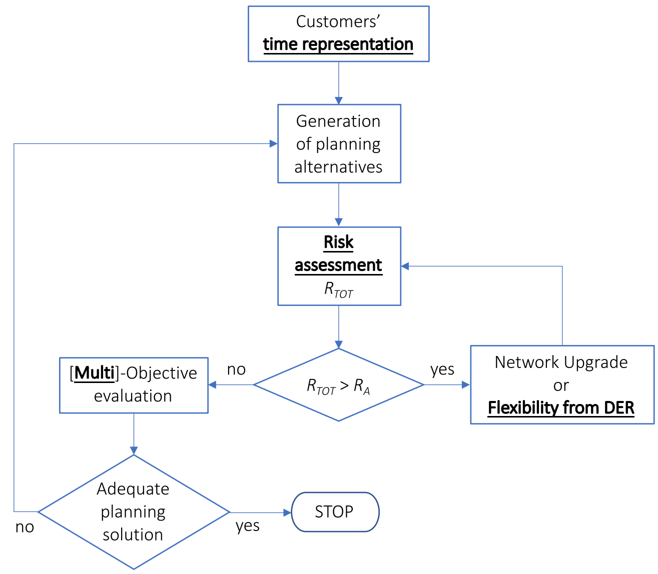

Fig. 1. Flowchart for modern distribution network planning.

2. *Risk assessment.* The abandonment of the worst-case approach is becoming even more undeferrable because the uncertainties of the new planning scenario have increased oversizing network hazard due to nullifying the risk for any constraint violation, even if some operating conditions are extremely rare or implausible. The new goal of a modern planning tool shall become the development of the distribution system, keeping the overall risk of technical constraints violation below a predefined allowable level (acceptable risk of violation, R_A in Fig. 1). Therefore, each planning option shall be characterised not only by its cost but also by its impact on the network risk. A proper probabilistic network calculation based on the stochastic representation of customer behaviour is essential for this risk assessment. If the overall risk characterising a specific distribution system (R_{TOT}) is greater than R_A, different planning options may be put in place (Fig. 1). By so doing, significant savings can be achieved even by accepting a small residual risk [9].
3. *Network upgrade or Flexibility from DER.* Particular attention must be paid to assess innovative planning options based on the exploitation of DER flexibility to perform a fair comparison with the traditional network reinforcement. Indeed, building a new line or installing a new transformer is well-known in terms of costs, reliability, and benefits. Instead, the usage of flexibility from external resources is still an unfamiliar planning option for DSOs. How many providers of flexibility does the DSO have to sign for achieving an effective implementation? How much does the DSO have to pay for the exploitation of such flexibility? Which is the residual risk of solving a specific contingency by resorting to flexibility services procured in a local market or through bilateral contracts? The paper proposes a methodology for answering such questions by calculating not only the amount of risk reduction associated with every planning option but also the intrinsic risk related to the exploitation of flexibility from DERs or, in other terms, how reliable are these flexibility services.
4. *[Multi]-Objective evaluation.* The conflicting goals of system stakeholders (e.g., energy companies, regulators, and producers) in some unbundled electricity markets increases

```
begin
    Load network data
    Generate candidate links for each secondary substation (network nodes)
    if Existing Configuration (EC) is fully connected then
        Starting Configuration (SC) = EC
    else
        Create a Starting Configuration (SC)
    end if
    Objective Function evaluation (OF_SC)
    Set Best Configuration (BC) = SC and OF_best = OF_SC
    repeat
        for each secondary substation (node i)
            for each candidate link (j) of node i
                for each feasible move that involves node i and candidate link j
                    create a New Configuration (NC)
                    Objective Function evaluation (OF_NC)
                    if OF_NC < OF_best then
                        BC = NC and OF_best = OF_NC
                    end if
                    restore SC
                end
            end
            if BC ≠ SC then
                SC = BC
                A new best is found
            end if
        end
    until a new best is found
end
```

Fig. 2. Pseudo-code of the traditional single-objective optimisation approach.

the need for finding new compromise solutions in a multi-objective approach. Tools based on such techniques are particularly useful for regulators when verifying the impact of different regulatory scenarios.

3. Risk-oriented planning

3.1. Optimal expansion planning tool

Over the last three decades, the authors developed a software package for the optimal expansion planning of MV distribution systems. The optimal DG allocation [27], the probabilistic distribution network assessment [28], the Multi-Objective distribution system planning [29], and the inclusion of DER flexibility as a planning option [30,31] are some of the most important features of the package.

Assuming the point of view of a DSO, the traditional single-objective optimisation approach is adopted in the paper, whose pseudo-code is reported in Fig. 2. A classic "branch & bound" technique is adopted for generating new network schemes: suitable prefixed moves are applied to create perturbations to the network topology (adding and/or cutting lines). Only such moves that improve the objective function (i.e., that reduce the overall network cost) are accepted and saved.

For each configuration created, network calculations are performed to check technical constraints and eventually apply resolving actions (pseudo-code shown in Fig. 3). The main novelty of this paper is the implementation of a risk-oriented planning

```
Function Objective Function evaluation (OF_CC)
    Load data of Current Configuration (CC) – links among nodes and existing cross-sections
    Risk assessment of CC (R_TOT)
    if R_TOT > R_A (acceptable risk) then
        flexibility exploitation and/or network reinforcement application to reduce R_TOT
        if reduced R_TOT is still greater than R_A then
            CC is disregarded (OF_CC = ∞)
            exit
        end if
    end if
    Optimal allocation of Automatic Sectionalizing Switching Devices (ASSD)
    Network costs assessment (new lines, line upgrades, ASSD) → C_N
    Flexibility exploitation costs assessment → C_F
    Cost of Joule energy losses assessment → C_L
    Energy not supplied cost assessment → C_ENS
    OF_CC = C_N + C_F + C_L + C_ENS
end
```

Fig. 3. Risk-oriented planning procedure pseudo-code.

procedure (the two nested if statements), as will be detailed in the next paragraph.

3.2. Risk assessment

A key aspect for the future design of a distribution system is the adoption of a risk-oriented planning procedure. The risks violating any technical constraints associated with a specific network planning configuration is, for this reason, explicitly assessed (flow chart of Fig. 4).

Risk assessment requires a probabilistic approach in opposition to the dominant but no longer suitable deterministic modelling. In accordance with the first key point of the flow chart of Fig. 1, each customer behaviour along the year (load or generator) has been represented with typical daily profiles. Different choices are possible about the number of profiles considered, depending on the desired compromise between accuracy of the results (high number) and computation time (low number). For instance, the simplest representation is with one typical profile for all the days in a year, while one of the most complex is with twelve profiles for working days, Saturdays, and Sundays for each of the four quarters in a year. Each profile is discretised in 24 h, and the uncertainty in the power consumed or generated is modelled through Normal probability density functions. It must be observed that the standard deviation values adopted for the 24 h of a specific typical day depend on the year portion represented, i.e., on the number of typical days considered. Indeed, if a single profile is used, the standard deviations should be greater in respect to the twelve-profiles model due to the wider variations of the consumption/production along the time-interval represented (one year vs three months).

In the proposed methodology, a linearised Probabilistic Load Flow (PLF) is solved for each of the 24 h 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 [28]. Thanks to the 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. Indeed, if X is a normal deviate with expected value μ and standard deviation σ, representing a specific nodal voltage or line current, it is known how to calculate the probability that X may exceed a predefined value (the voltage of current maximum limit – X_{max_lim}). Firstly, the Normal distribution of X is scaled and shifted via the formula $Z = (X - \mu)/\sigma$ to convert it to the "standard" normal distribution ($\mu = 0, \sigma = 1$). Then, the probability $P(Z > Z_{max\_lim})$ is calculated as the complement of the cumulative distribution function (Φ) of the standard Normal distribution:

$$P\left(Z > Z_{max\_lim}\right) = 1 - \Phi\left(Z_{max\_lim}\right) = 1 - \frac{1}{\sqrt{2\pi}} \int_{-\infty}^{Z_{max\_lim}} e^{-\frac{t^2}{2}} dt$$

Graphically, it corresponds to the highlighted area in the case A of Fig. 4. Instead, the probability $P(Z < Z_{min\_lim})$, related to the event that a specific nodal voltage might be lower than the minimum acceptable limit (X_{min_lim}), is simply assessed by calculating $\Phi(Z_{min\_lim})$. Being a Normal probability distribution characterised by infinite tails, p_{tcv} would be always greater than zero. In order to avoid this undesired situation, in the paper it has been assumed, as practical approximation, that the extreme values of nodal voltages and line currents are defined as $\mu_X \pm 3 \cdot \sigma_X$. Therefore, when these extreme values do not overcome the technical limits, then p_{tcv} = 0 (case B of Fig. 4).

By multiplying p_{tcv} and the occurrence probability of the relative operating condition, p_{bf} (fth hour of the dth typical daily profile when the bth network configuration in the N – 1 security analysis is in force), the corresponding risk component is determined (R_{bf}). The probability p_{bf} can be determined by simply multiplying the forced outage rate of the bth network element

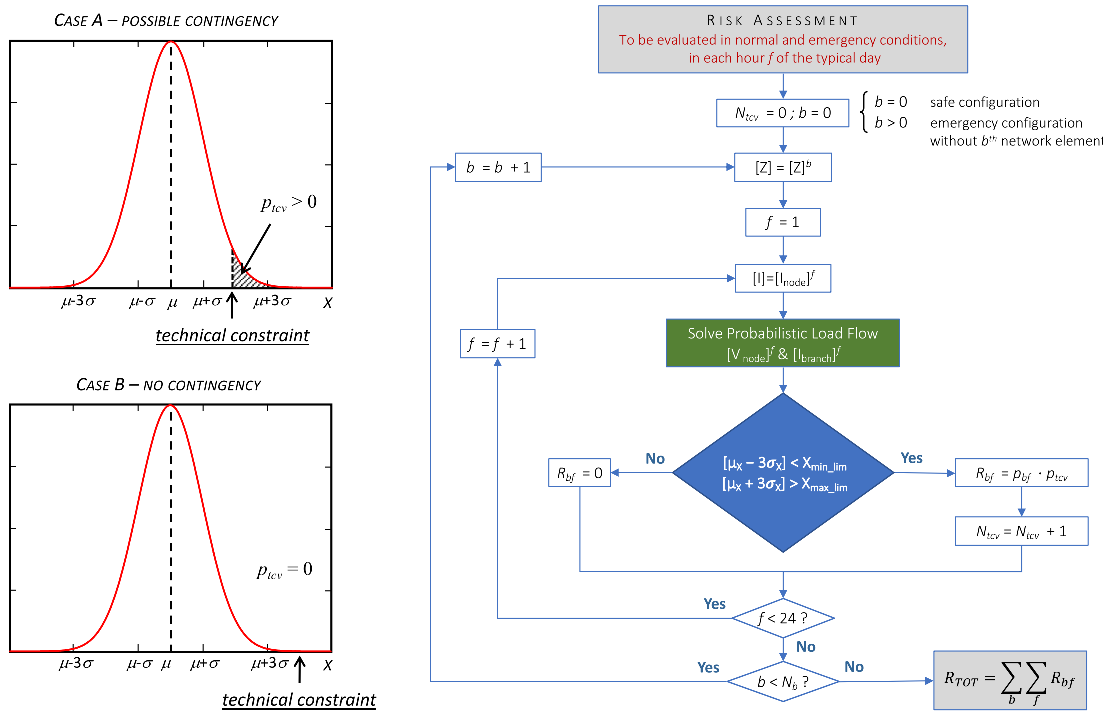

Fig. 4. Identification of potential contingencies ($ptcv > 0$) and flow chart of total risk assessment.

(FOR_b) and the occurrence probability of the specific customers' operating conditions (p_{fd}), because these two probabilities can be considered independent:

$$FOR_b = \frac{MTTR_b}{MTTF_b + MTTR_b} \qquad p_{fd} = \frac{nh_{fd}}{8760}$$

where:

- $MTTR_b$ is the "Mean Time To Repair" of the bth network element, indicated in the paper with the symbol τ_b and assumed equal to 5 h for an overhead line and 8 h for a buried cable;
- $MTTF_b$ is the "Mean Time To Failure" of the bth network element, expressed by definition as $8760/\lambda_b$, where λ_b is the fault rate assumed in the paper equal to 0.12 [faults/(year·km)] for overhead lines and 0.03 [faults/(year·km)] for buried cables;
- nh_{fd} is the yearly number of occurrences of the fth hour of the dth typical day (i.e., the specific conditions of power injected or absorbed in each node by every customer). If a single daily profile is used to describe the customers' behaviour in the whole year, then nh_{fd} = 365 h and the occurrence probability p_{fd} = 1/24; if two semesters are simulated, p_{fd} = 1/48, and so on.

For a distribution network, it is evident that $MTTF >> \mathrm{MTTR}$ (years compared to few hours). Consequently, MTTR can be disregarded in the denominator of the first of Eq. (2), and it is acceptable to assess the occurrence probability p_{bf} with the following approximated formula:

$$p_{bf} = \left(\tau_b \cdot \frac{\lambda_b}{8760}\right) \cdot \left(\frac{nh_{fd}}{8760}\right)$$

When the normal configuration is examined (b = 0), FOR_b is assumed equal to 1 and $p_{bf} = p_{fd}$.

Finally, the risk component R_{bf} can be expressed in hours of violation per year:

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

The sum of all these N_{tcv} terms gives the total risk of the whole network, R_{TOT}, (i.e., the number of hours per year when it is possible to overcome one or more technical constraints, both on nodal voltages or branch currents), that has to be compared with the acceptable one, R_A, chosen by the planner. If $R_{TOT} > R_A$, planning options are put in place (Fig. 5).

For each adverse event with 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 minimise 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, and the 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}) to 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 becomes smaller than the maximum allowable risk (Fig. 4). Alternatively, the process can be adapted to estimate the residual risk of a distribution network planning optimisation when a maximum available budget is given.

3.3. Uncertainty on the provision of flexibility

The optimal exploitation of the available flexibility from DER (green box in the flow chart of Fig. 5) is attained by solving a Linearised Optimal Power Flow (LOPF) with a Linear Programming (LP) approach that minimises a cost-function expressed as the weighted sum of the flexibility services subject to network constraints [30]. The flexibility services considered are:

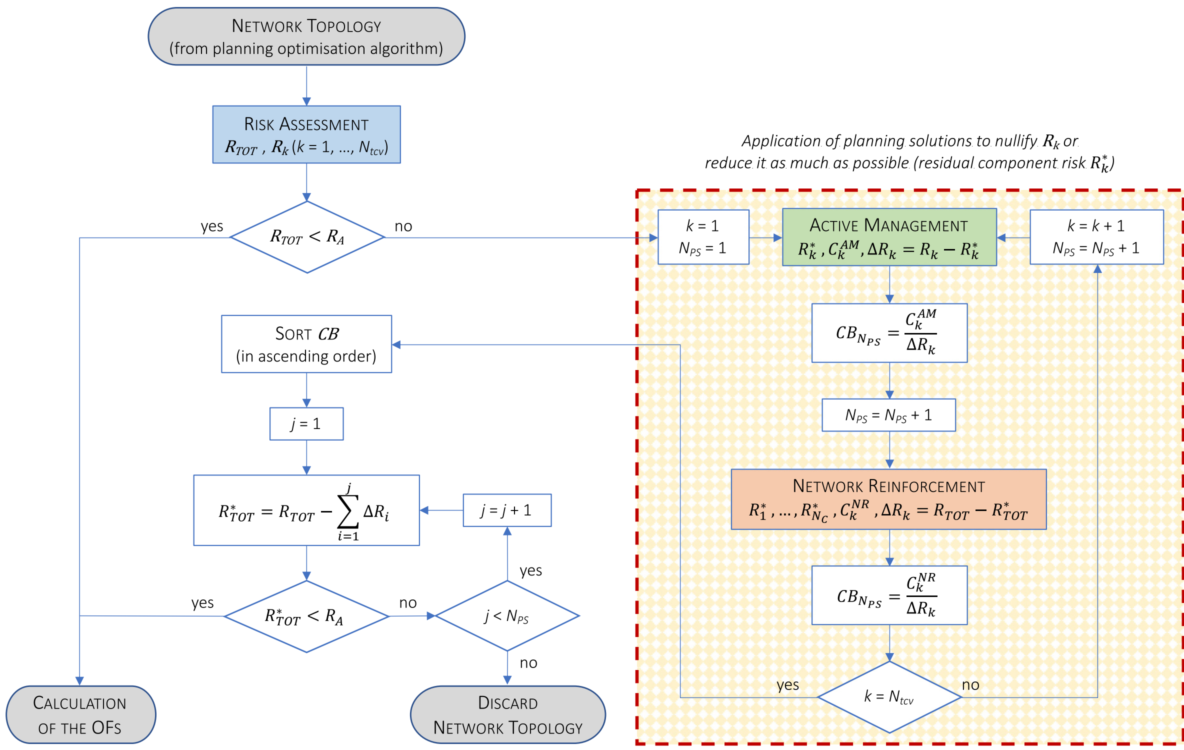

Fig. 5. Identification of the best cost-effective planning solutions for the minimisation of the total risk.

- the active power curtailed from MV generators,
- the reactive power provided by the MV generators,
- the active power curtailed from the electricity consumption of MV customers involved in the DR programs,
- the variation of the active power exchanged by the aggregations of LV DER.

The weights are proportional to the purchasing costs of the corresponding flexibility services. The network constraints, corresponding to the nodal voltage and the ampacity limits, are linearised by using suitable sensitivity coefficients for each nodal voltage and each line current with respect to the unitary active (reactive) power variation from each single flexibility provider [15]. Additional constraints are the maximum flexibility that each DER can provide. The LOPF looks for the optimal mix of DER capable of fixing network operating issues in normal and emergency conditions at minimum costs. If the available resources are not sufficient to satisfy all network constraints, suitable slack variables are introduced in the LP formulation in order to assure always a feasible solution to the mathematical problem and, consequently, the possibility to estimate the residual risk of network technical limits violation (R_k^*) [15].

By applying this optimisation to all the risk components that characterise a specific network configuration, the planner knows which DER have to be involved in the active management and how much flexibility is needed to support the operation of the examined network configuration within the planning horizon. However, this approach implicitly assumes that all DER would be continuously available to provide the requested flexibility leading to a possible overestimation of benefits. A contract-based and a market-based model for the procurement of flexibility have been considered in the paper to estimate the impact of the uncertainty on flexibility provision.

In the contract-based case, the DSO signs flexibility providers with a bilateral contract stating the maximum number of products and the relative quantity per year. So, the resources are committed to being available. The expected reliability and availability of the resources are dealt with in the contract that defines the share of responsibilities among the involved parties (e.g., the communication network role) and possible penalties if they lack the goal. In planning, the uncertainty impact may be estimated by performing an $N-1$ analysis. The LOPF is first solved with all the available resources to find DER. The LOPF is repeated by assuming one at a time of this resources unable to modify its scheduled set-point (i.e., unable to provide flexibility) and identifying the flexibility increment needed to deal with the uncertainty.

Alternatively, DER may present their offers in a local market, where the DSO has to procure the needed flexibility. In this case, the probabilities of DER unavailability are higher since volumes and prices cannot be attractive for players who may decide not to present offers. A Monte Carlo (MC) simulation simulates the impact of the high volatility market and its role on system development. In the paper, the behaviour of DER in the market has been assumed to follow a stochastic pattern. For each MC simulation, non-participating on the market DERs are randomly extracted, and the amount of residual flexibility (necessary for the network operation) offered by the available resources is calculated. This information is used in optimisation to check whether it is possible to buy enough flexibility to overcome the specific contingency or evaluating the residual risk.

The final impact of the unideal provision of flexibility is a higher number of resources that have to be involved in the network operation and, thus, a higher cost of flexibility procurement, being not always involved the most valuable resources for solving the network contingency.

4. Integration of the LV network in the MV planning

As stated before, the importance of the LV system is increased in the last years thank the technology improvements that allow the involvement of end-users in system operation. In this paper, a sequential optimisation of LV and MV networks by integrating

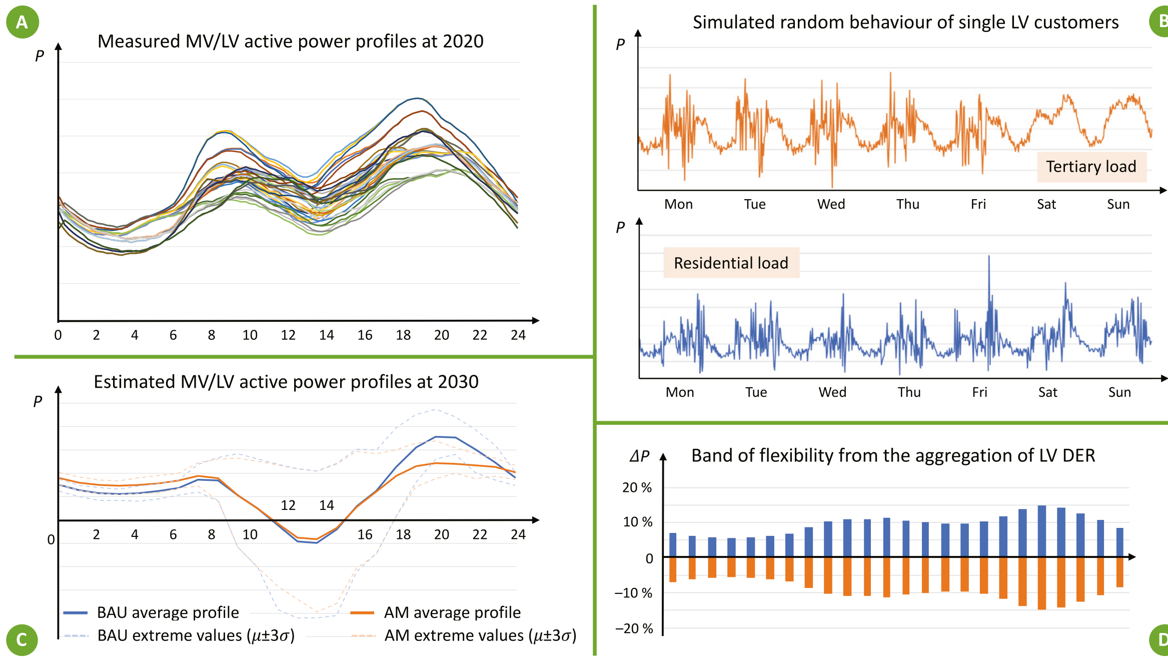

Fig. 6. Derivation of the LV system model suitable for the MV probabilistic planning analyses.

the synthetic results of the LV system analysis into the MV system model is adopted. Such approach should perform an iterative cycle of optimisations until an ad hoc convergence criterion will be reached (e.g., the difference between the results of one iteration and the previous one on the same model is smaller than a predefined threshold). However, such an iterative procedure is not implemented in this application because it is expected that the mutual impact between LV and MV network operation will be minor, especially if the activation of services for LV grid purposes is not simultaneous or occurs in different parts of the MV network. Furthermore, in the paper, it is hypothesised that the DSO decides to equally share the allowable voltage reduction between LV and MV networks (i.e., ±5% the nominal voltage for each voltage level). Thus, the results are obtained by considering such strict limits that even summed do not overcome the allowable constraint.

To include the support of the LV system has been studied considering two scenarios: business-as-usual (S_{BAU}) and Active Management (S_{AM}). In the S_{BAU}, no control action is put in place neither on demand nor on generation. EVs are immediately charged when they are connected to the charging point ("dumb" charging). In the midday, the LV network may experience excessive overvoltage and overcurrent or both due to the PV generation peak. Extreme voltage drops are common in the evening due to the peak demand accrued by the simultaneous EVs recharge, especially in the "dumb" charging mode.

In the S_{AM} scenario, a decentralised control architecture based on a Multi-Agent System (MAS) is used to implement DR programs, Volt/VAR control of PV plants, and smart EV recharge. It is supposed that each agent performs a local and independent optimisation of a DER, based on a specific objective function (for instance, the local nodal voltage regulation), and by receiving only a few data from the master agent (like network state and service price) [32,33]. Besides broadcasting these data, the master agent acts as an aggregator that receives remuneration from the DSO for the local support provided to the LV system and offers the residual amount of flexibility from its aggregated resources for MV system support.

To build a suitable model for the probabilistic planning analyses, a top-down approach for properly scaling the MV power profile to the LV network has been performed, by randomly generating daily sequences of LV load consumption and PV generation (Fig. 6B), taking into account:

- the DSO measurements at the MV/LV substations (Fig. 6A),
- the yearly energy consumption of each LV customer registered at the beginning of the planning period and used to share the measured profile at the distribution transformer among all customers,
- Beta distribution for the LV consumption, and normal distribution for DG production for modelling uncertainty,
- the expected growth of demand and generation assumed in the planning study, and
- the weakly and seasonal variations of consumption and generation.

All the LV system states are firstly evaluated with a 4-wire unbalanced load flow, identifying which lines need to be upgraded to solve possible network contingencies (S_{BAU}). Then, the system states are optimised with the Multi-Agent optimisation to reduce these technical issues as much as possible and to identify which customers need to be involved and how much and how frequently they have to participate (S_{AM}). One or multiple daily profiles (representative of the whole year) can be defined to represent the LV system behind the MV/LV transformer in terms of average values and standard deviations (assumption of Gaussian distribution, Fig. 6C), with the additional information of the available band of flexibility offered by the LV DER (Fig. 6D).

5. Case study

The proposed planning methodology has been tested on a real portion of the Italian distribution system (Fig. 7). The MV feeder is fed directly by one Primary Substation (PS) and has an emergency connection with an adjacent feeder.

Topologically, the MV nodes are classified into trunk and lateral. The former group includes those supplied by at least two

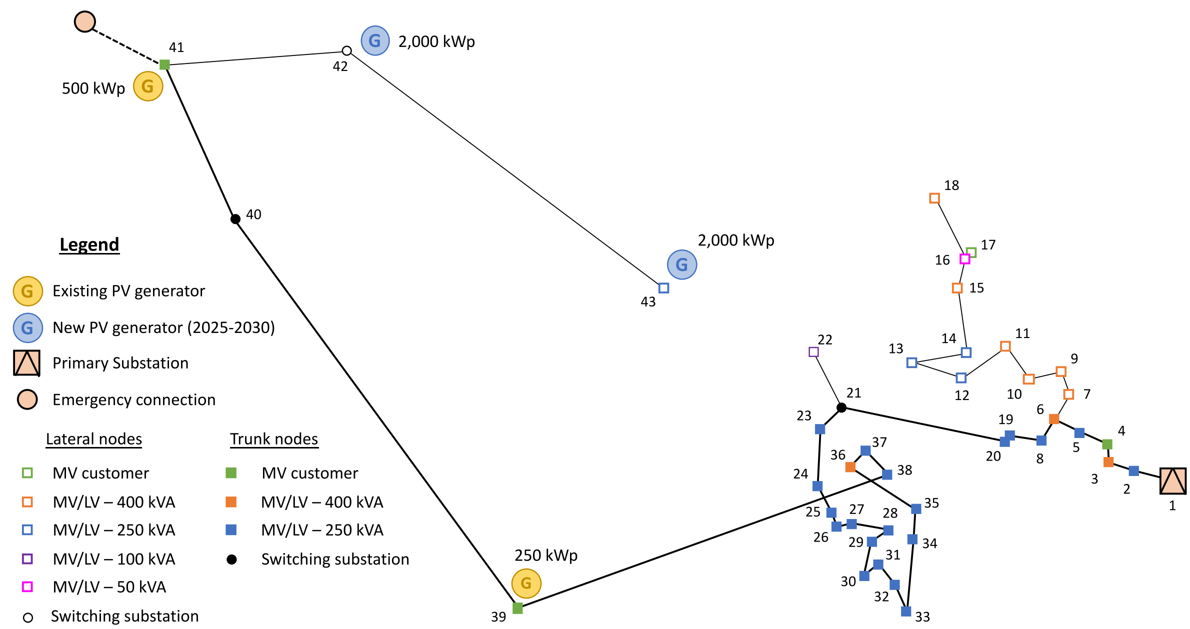

Fig. 7. MV feeder of the Italian distribution system.

Table 1
Definition of planning scenario.

Distribution level	System growth data	Planning intervals	
		2021–2025	2026–2030
MV system	yearly MV demand growth rate	1%	3%
	new generation plants	0%	2 PV (2 MW each)
	percentage of LV customers with EV charging point at the end of the planning interval	18%	30%
	percentage of LV customers with PV rooftop plants	28%	36%

distinct paths (from the same or a different PS) and can then be resupplied in case of a line fault. The lateral nodes are connected to the PS through a pure radial network. Thus, a line fault can cause the isolation of the nodes downstream of the fault.

The full extension of the MV feeder is about 28.7 km, built prevalently with overhead insulated cables of different cross-sections (from 85 mm^2 up to 185 mm^2 aluminium conductor). Its first part (up to node 38) supplies a semi-urban area (average line length of 373 m), then it continues with long lines in the near countryside. Two PV plants exist (500 kW and 250 kW) at the beginning of the planning period (2020). The whole electric demand is about 5.45 MW, almost entirely formed by LV customers (35 MV/LV substations and only four relatively small MV customers).

The planning scenario follows the National Energy and Climate Plan (NECP) that fixes the Italian global targets for 2030 (30% share of energy from RES in the gross final energy consumption, 39.7% reduction of final energy consumption compared to the PRIMES 2007 scenario) [34]. Furthermore, for defining the LV scenario, the study in [35] has been considered. By assuming an initial slow realisation of these goals and a hastening in the second half of the next decade, the ten years planning period has been divided into two sub-intervals (2021–2025 and 2026–2030), with the growth details for demand and generation in MV and LV systems summarised in Table 1.

Specifically, from the LV side, significant growth of the energy absorbed has been modelled by including the installation of several residential EV slow charging stations that naturally tend rising the evening peak demand of the residential customers. Fast charging stations can be easily added as well as public parking lots contributing to the operation network even though they are not considered in the proposed example. Other parameters of the planning problem are grouped in Table 2. For the sake of simplicity, the discount rate is considered constant during the whole planning period.

For the LV system, some real networks are extracted from a database of real Italian LV networks. The exemplary LV networks are chosen considering the MV/LV transformer capacity. The LV networks are assigned to the 35 MV/LV substations of Fig. 7 according to the relevant MV/LV transformer. By way of example, the extracted LV system fed by a 250 kVA transformer is depicted in Fig. 8. It is an urban distribution case with three feeders built with buried cables for a global extension of 1.7 km (the farthest customer is distant more than 620 m from the MV/LV substation). The network supplies 157 residential and 47 commercial customers. Six single-phase PV plants are installed at the beginning of the planning period. With the hypotheses assumed for the planning scenario definition [34,35], 34 new PV plants will be installed by 2030 (the green PV plants in Fig. 8), together with 19 residential EV charging points.

The proposed planning methodology starts with the analysis of the LV system. All the smallest LV networks (50 kVA and 100 kVA) already suffer from temporary and sporadic voltage drops, as typical of rural distribution (overhead lines, a relatively high imbalance degree, and a significant neutral conductor current). In 2030, the EV dumb recharge causes considerable evening voltage drops, particularly in winter. Besides, the PV growth causes

Table 2
Main parameters used for the planning calculations.

Planning parameters			Values
Discount rate			6.9%
Technical operating limits	Voltage deviations	ordinary operating condition	±5%
		emergency operating condition	±10%
	Overload	ordinary operating condition	0%
		emergency operating condition	+10%
Acceptable risk			5 [hours/year]

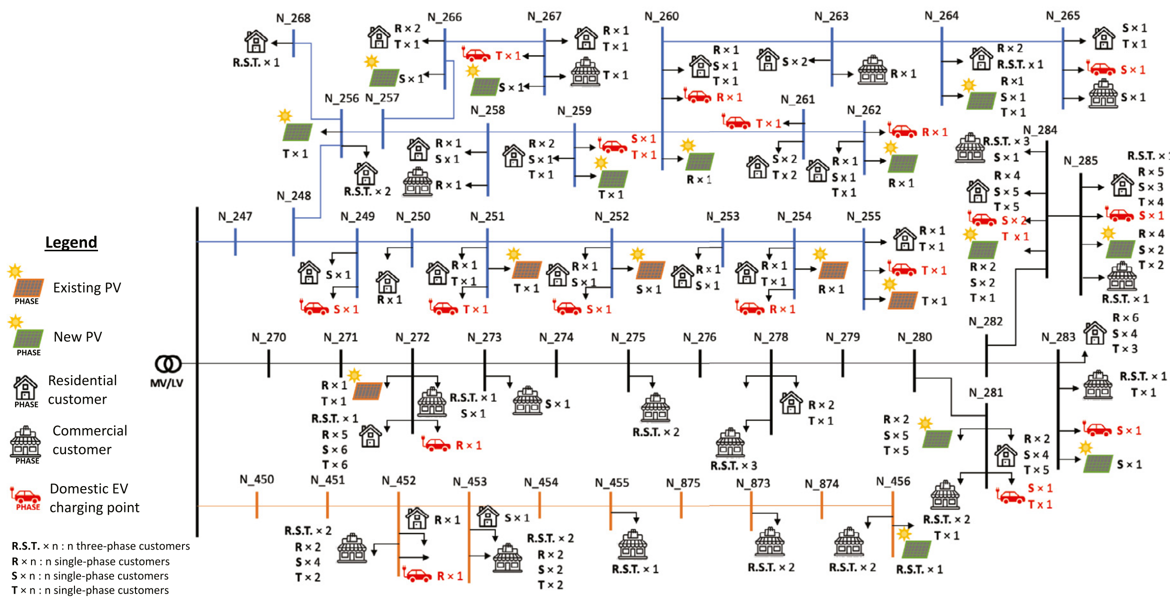

Fig. 8. Schematic representation of the 250 kVA LV system in 2030.

overvoltages in the midday, especially in summer, with a frequent reverse flow at the distribution transformer (see, as an explanatory example, the case of Fig. 6C).

Within the S_{BAU}, several LV lines should be upgraded to respect the technical limits. Alternatively, in the S_{AM}, almost all these critical events are solved by postponing the EV recharge after midnight (preserving the target of achieving the state of charge requested in the early morning) and, occasionally, by applying small generation curtailments. Regarding the other resources of flexibility (DR and var control), a very small and unattractive contribution can arrive from possible DR programs due to the assumed null growth rate of the conventional LV load (Table 1). Obviously, with different planning scenarios (e.g., load electrification), this action would play a key role in the correct LV system operation. It is worth noting that the developed planning tool models DR actions together with the probable payback effect, represented by the recovering of part of the demand curtailed in the hours immediately after the DR signal [36]. Instead, reactive management is partially helpful only in the smaller rural LV networks, where a higher reactance characterises the overhead distribution.

At the end of the LV system analysis, each MV/LV substation is modelled with ad hoc daily profiles of power generation and demand for S_{BAU} and S_{AM} scenarios (as represented in Fig. 6C) and the flexibility band for the MV system management (Fig. 6D). The optimal planning of the MV network is obtained under these assumptions. At the beginning of the planning period, the MV network does not suffer from evident technical issues, even if the probability of operating the system near to its voltage technical limits is not negligible. Frequent overvoltages coincident with the PV generation peak and less frequent evening voltage drops only when if the network reconfiguration changes the network topology to minimise the impact of line faults. If the existing MV system were kept unchanged up to the planning horizon (2030), it would be characterised by a very high risk of technical constraint violations equal to about 372 hours/year (4.2% of the time in a year), confirming the need of system development. The following planning approaches have been studied:

1. *FF* – Traditional *fit & forget* (S_{BAU} for LV system);
2. $RP_{passive}$ – Risk-based planning with passive network management (S_{BAU} for LV system);
3. RP_{active} – Risk-based planning with Active Management of generation (active and reactive power control) and exploitation of LV DER flexibility (S_{AM} for LV system):
    a. Considering bilateral contract (RP_{active_BC}),
    b. Considering the participation in a local Market (RP_{active_ASM});
4. RP_{ESS} – Risk-based planning with the installation of ESS in the MV network, owned and operated by the DSO, without any control actions of DERs (S_{BAU} for LV system).

The comparison among the different planning strategies (Table 3) is made in terms of pure network investment savings ($\Delta Netw\_Inv$) and total investment savings, including the cost of the AM (ΔTot_Inv), both savings evaluated in respect of the *FF* case, the residual risk (R^*_{TOT}), and percentage of MV DER involved in the system management (only for AM cases). For the latter point, it should be noticed that the activation of AM in the LV systems allows avoiding voltage drops thanks to the smart control

Table 3
Comparison of the different planning strategies.

Planning strategy	MV/LV profile	*ΔNetw_Inv* [%]	*ΔTot_Inv* [%]	$R^*_{TOT.}$ [h/years]	% gen: $\%N_{gen}$ ($\% P_{gen}$)
$RP_{passive}$	BAU	−58%	–	4.6	–
RP_{active_BC}	AM	−91%	−90%	4.8	50% (47%)
RP_{active_ASM}	AM	−91%	−89%	4.9	75% (89%)
RP_{ESS}	BAU	−67%	−9%	4.5	–

of the EVs recharge. It is unnecessary to resort to additional DR actions, and the only MV resources necessary to control are the four PV generators. For this reason, in Table 3 the comparison only reports how many PV plants ($\%N_{gen}$) and how much rated power ($\%P_{gen}$) have been involved in the active management of the system.

The *FF* approach leads to high network investment due to the conservative hypotheses (worst case scenario and $R^*_{TOT} = 0$) that brings to upgrade many trunk lines (up to the maximum standardised cross-section). Adopting the risk-based planning strategy ($RP_{passive}$) reduces the capital expenditure by 58% since upgrading the trunk conductors up to the maximum cross-section is not necessary if a small residual risk is accepted. Indeed, the total residual risk remains under the acceptable limit (4.6 hours/year of overvoltage in the second subperiod characterised by the higher increment of generation), confirming the negligible probability occurrence of the most extreme operating conditions.

A further reduction of the network investment can be achieved with the active management implementation (up to 91%). Indeed, qualifying the generators' reactive support, the long lateral upgrade that supplies nodes 42 and 43 can be avoided, limiting the network refurbishment only to few trunk lines. Besides, sporadic generation curtailments are requested with few emergency configurations during the central hours of the day. The energy curtailed is only around 1% of the annual production. The number of calls for curtailment is minor than two per year on average, for the low probability of emergency operational conditions. The slight difference between *ΔNetw_Inv* and *ΔTot_Inv* is motivated by the remuneration model adopted for the AM involvement. Indeed, only a remuneration in energy has been considered (at energy market price), while the capacity remuneration has not been applied. Different regulation scenarios can be implemented, but the considerable savings achievable with DER flexibility exploitation seem widely sufficient to cover additional expenditures. It must be observed that in Table 3 the AM costs of the LV system are also included, weighting for 40% of the overall energy remuneration (in the specific example). The difference between the two AM cases is in the number of MV generators involved. Indeed, with bilateral contracts, the DSO has to sign only two PV plants (those in nodes 39 and 42). The higher uncertainties that characterise the flexibility procurement from the local market require a third generator (node 43) that, being less effective in resolving the specific contingencies, entails a slightly higher energy remuneration.

Finally, two installations of ESS, connected in nodes 41 and 43 (500 kW, 4000 kWh each), are considered, following the approach in [36]. They absorb the energy produced by PV generators and exchange reactive power with the network. In that case, the results are still excellent in terms of network investment savings (–67%), even if the high capital expenditure drastically reduces the overall convenience (*ΔTot_Inv* = –9%).

6. Conclusions

The paper presents the results of risk-oriented planning in MV and LV distribution.

The benefits of non-deterministic models are clearly shown with the aid of real-world examples. It is clear that with a full risk assessment in planning, the DSO can include the resort to flexibility products as a valuable development option to cut or defer investments for distribution network development both in MV and LV without limiting the network hosting capacity. The amount of flexibility required is generally small in terms of energy. Bilateral contracts between DSO and customers seem the most effective mechanism for engaging the flexibility providers for the distribution system operation. Flexibility markets are better suited for the provision of flexibility to the TSO. The cooperation of TSO and DSO is crucial to avoid cases that can degrade service continuity and voltage regulation in the distribution systems.

CRediT authorship contribution statement

Gianni Celli: Conceptualization, Methodology, Visualization. **Fabrizio Pilo:** Conceptualization, Methodology, Writing – review & editing, Supervision, Funding acquisition. **Giuditta Pisano:** Formal analysis, Investigation, Validation, Writing – review & editing. **Simona Ruggeri:** Software, Data curation, Investigation, Writing – original draft. **Gian Giuseppe Soma:** Software, Validation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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