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# Reactive power provision by the DSO to the TSO considering renewable energy sources uncertainty

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ABSTRACT

The current coordination between the transmission system operator (TSO) and the distribution system operator (DSO) is changing mainly due to the continuous integration of distributed energy resources (DER) in the distribution system. The DER technologies are able to provide reactive power services helping the DSOs and TSOs in the network operation. This paper follows this trend by proposing a methodology for the reactive power management by the DSO under renewable energy sources (RES) forecast uncertainty, allowing the DSO to coordinate and supply reactive power services to the TSO. The proposed methodology entails the use of a stochastic AC-OPF, ensuring reliable solutions for the DSO. RES forecast uncertainty is modeled by a set of probabilistic spatiotemporal trajectories. A 37-bus distribution grid considering realistic generation and consumption data is used to validate the proposed methodology. An important conclusion is that the methodology allows the DSO to leverage the DER full capabilities to provide a new service to the TSO.



## 1. Introduction

The distribution grid has been continuously evolving, especially with the deployment of DER, mainly based on RES. Operating a distribution grid with a large share of RES requires the adaption of current practices and the development of new methodologies to deal with the uncertain and variable behavior of RES [1]. These new methodologies may require a more preventive behavior of DSOs, by contracting/controlling DER flexibilities to solve potential congestion and voltage problems [2].

The current and the new methodologies for operating and managing the distribution system should be conciliated to foster the power system transition, in which DERs play a vital role [3]. In fact, the new preventive management methodologies may be compatible with the conventional network management in a way that complements the needs of the DSO facing the challenges of RES penetration.

Bearing this in mind, it is crucial to define coordination methodologies between system operators to optimize the use of the existing flexibilities. Some DSOs are actually changing the way of operating and managing the distribution system, namely, by considering the inclusion of forecasts in the operational planning tools and by doing contracts to anticipate network operation problems and have available flexibilities to solve them [4]. DERs can contribute to solve congestion and voltage problems by providing flexibility changing their expected operating point. The flexibility can be designed either in active or reactive power, allowing the DSO to solve network problems at a certain cost [5]. By using the DER flexibility, the actual role of the DSO remains intact, which is ensuring equal network access to all users (consumers and producers) with proper levels of security, safety and stability, as well as the required service quality [6].

The preventive management mechanism addressed in this paper allows for a better coordination between TSOs and DSOs in order to reduce the probability of voltage limits violations in transmission and distribution systems. To achieve to this reduction, *(i)* the TSO can request a specific reactive power operation point in the TSO/DSO boundary that should be respected by the DSO and *(ii)* the DSO can request a specific voltage level in the TSO/DSO boundary that should be respected by the TSO. In both cases, power systems analysis should be performed by TSO and DSO to verify that is possible to answer positively to the request. Considering the first request *(i)* the DSO should use their own resources to control the reactive power in the TSO/DSO boundaries but also the reactive power operation point of DERs connected

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**Nomenclature**

**Parameters**

| | |
|---|---|
| $\Delta P$ | Power deviation in each scenario $\omega$ |
| $B$ | Imaginary part of the admittance matrix |
| $C$ | Cost |
| $G$ | Real part of the admittance matrix |
| $N$ | Number of unit resources |
| $p$ | Penalty for external supplier's flexibility |
| $T$ | Time horizon |
| $\bar{y}$ | Series admittance of the branch that connects two buses |
| $\bar{y}_{sh}$ | Shunt admittance of the branch that connects two buses |

**Variables**

| | |
|---|---|
| $\theta$ | Voltage phase angle |
| $P$ | Active power |
| $Q$ | Reactive power |
| $r$ | Reactive power flexibility used in the operating stage |
| $rlx$ | Reactive power relaxation in the operating stage for $su$ |
| $R$ | Reactive power flexibility contracted at the day-ahead stage |
| $RLX$ | Reactive power relaxation at the day-ahead stage for $su$ |
| $S$ | Apparent power |
| $V$ | Voltage magnitude |
| $\bar{V}$ | Voltage in polar form |
| $V_{sb}$ | Voltage at slack bus |
| $\Delta V$ | Voltage level activated by the DSO in the transformer |
| $X$ | Binary variable |
| $Z$ | Auxiliary variable for absolute function linearization |

**Subscripts**

| | |
|---|---|
| $\omega$ | Index of scenarios |
| $cb$ | Index of capacitor bank units |
| $CB$ | Capacitor bank abbreviation |
| $g$ | Index of generators units |
| $i, j$ | Bus index |
| $l$ | Index of load consumers |
| $L$ | Load consumers abbreviation |
| $lv$ | Index of levels (tap changing) for capacitor banks and transformers |
| $su$ | Index of external supplier units |
| $SU$ | External supplier abbreviation |
| $t$ | Time index |
| $trf$ | Index of transformer units |
| $TRF$ | Transformer abbreviation |

**Superscripts**

| | |
|---|---|
| $act$ | Activation cost of resources in real-time stage |
| $cut$ | Generation curtailment power for energy resources |
| $Max$ | Maximum limit |
| $Min$ | Minimum limit |
| $NS$ | Non-simultaneity of energy resources |
| $op$ | Operating point of the power resource |
| $policy$ | Proposed reactive power policy |
| $Q, DW$ | Downward reactive power flexibility |
| $Q, UP$ | Upward reactive power flexibility |
| $DR$ | Demand response of consumer l |
| $standard$ | Standard reactive power policies |

in distribution grids. The DSO establishes the bands and limits for reactive power provision by DER, accounting for their type of generation and intrinsic characteristics, and following the rules and policies established in each country [7]. Thus, reactive power management mechanisms are crucial to the DSO to improve the coordination with the TSO by assuring better levels of voltage control in the power system, as shown in deliverable 1.2 of TDX-ASSIST project [8].

The literature is very rich on reactive power management approaches considering that active power injections are precisely known and remain unchanged during the reactive power control [9,10]. However, such assumption is not compatible for distribution grids with a high penetration of RES. Still, several works have been integrating the uncertain and variable behavior of RES in the reactive power management. A stochastic framework for reactive power management considering the reactive power injection of controllable DER units is modeled in [11]. However, it uses a linearization of the nonconvex nonlinear AC-OPF problem through second-order cone programming, which is an approximation of the actual system behavior. On top of this, authors from [12,13] implemented and compared the two-stage stochastic and robust approaches. Their approach decomposes and solves the second-stage problem in several sub-problems through column-and-constraint generation algorithm methodology, claiming that it decreases the computational effort compared to conventional approaches. Though their solutions are obtained with a good computational effort, their accuracy to the optimal solution should be improved. In this regard, this work does not assess the tradeoff between solution accuracy and computational performance. In [14], a model is proposed for active and reactive power management considering a complete AC-OPF with individual and independent offers for active and reactive power support. Though it considers DER support for reactive power in a market environment, it does not allow merging with standard DSO operation because capacitor banks and transformers are disregarded. This means that it is not feasible in real systems to consider reactive power support to the DSO without considering the behavior of DSO devices, as they may react in the opposite direction to DERs regulation. Similarly, a linear active and reactive power management based on unit commitment problem is proposed in [15]. Nevertheless, the reactive power management is limited to the provision of reactive power from generating units, disregarding the use of capacitor banks and transformers with on-load tap-changer (OLTC) capability [15]. A stochastic algorithm for reactive power dispatch is proposed in [16]. The methodology is based on a sequential procedure where a linear deterministic reactive power dispatch is solved considering point-estimated methodology for wind generation, and then the solution is validated for network constraints through the Gauss–Seidel method. Though the approach provides fast convergence, it does not guarantee the best solution as it seeks the first feasible solution. A two-stage stochastic corrective voltage control model is used in [17] for transmission networks assuming total upward and downward active power controllability of the generating units (including wind turbines) and considering demand response to support reactive power control. The study considers a quadratic approximation of the AC-OPF, which limits solution accuracy. A stochastic voltage and reactive power control is modeled in [18], based on sampling from a sequence of probability distributions of all possible settings of transformers with OLTC and capacitor banks, but failed to model DERs reactive power support. A discrete-time stochastic process is proposed in [19] to deal with the uncertain production of PV units on a decentralized and full linearized active and reactive power control. This model is limited considering a single type of DER and by the standard AC-OPF linearization. On the other hand, [20] proposes a stochastic multi-objective reactive power dispatch, in which the cost for contracting reactive power in advance of the operating stage are disregarded, being the reactive power dispatch only dependent on the active power operating cost, i.e., the cost of DER reactive power support is ignored. The coordination of reactive power between TSO and DSO is widely discussed in [21]. This study proposes a hierarchical coordination of energy dispatches considering DER, but is limited by convex linearization of AC-OPF, as well as it disregards any source of uncertainty. Complementarily in [22], it is considered a stochastic reactive power management with full AC-OPF, yet disregarding the full capability of DER due to inadequate standard reactive power policies for DER support of reactive power.

Most of these works rely on linear approximations of the AC-OPF to obtain a solution close to the optimal one. However, the set of feasible convex solutions deviate from solutions of the original problem. Thus, the accuracy of modeling the real behavior of distribution systems is skewed and non-optimal.

In this context, this work proposes to overcome the identified limitations by: *(i)* modeling a complete two-stage stochastic reactive power management model for supporting decision-making of a DSO under the uncertain and variable behavior of RES at the distribution grid; *(ii)* considering a full AC-OPF model to properly characterize the power flow in the distribution system; and *(iii)* address TSO/DSO interaction through reactive power needs at TSO/DSO boundaries. Furthermore, the model addresses an innovative trend of booking reactive power flexibility ahead of the operating stage to ensure proper levels of reactive power in the TSO/DSO boundaries. The reactive power flexibility is obtained by considering that DSO can have specific contracts with DERs to control the reactive power in case of network constraints violation. Thus, this tool supports the DSO with solutions able to mitigate voltage problems, ultimately providing reactive power support for coordination services with the TSO. The main contributions of the study are fourfold:

- To analyze and compare different types of reactive power flexibility contracts considering the present policies in Portugal and France;
- To propose a distinct model for supporting the DSO reactive power management under uncertain and variable power production, considering the use of reactive power flexibilities following standard reactive power policies;
- To model a local reactive power service to be provided by the DSO to meet TSO needs in advance of the operating stage;
- To define a new reactive power policy to cover reactive power flexibility from DER, over the standard reactive power policies;
- To improve the full AC OPF tool developed in [23], by adding stochastic optimization to cope with RES power forecast uncertainty.

**Table 1**
Reactive power policy for the special scheme.

| Voltage level | $\tan\varphi$ | |
|---|---|---|
| | Peak period | Off-peak period |
| HV | 0 | 0 |
| MV (P > 6 MW) | 0 | 0 |
| MV (P ≤ 6 MW) | 0.3 | 0 |
| LV | 0 | 0 |

This paper is structured as follows. Section 2 describes the reactive power management problem faced by DSOs, accounting for current and future trends. Section 3 presents the formulation of the stochastic approach for reactive power management. Section 4 assess the proposed model based on a 37-bus distribution network with real data. Section 5 highlights the most important conclusions.

## 2. Framework for reactive power management

### 2.1. Current reactive power policies

DSOs typically use capacitor banks and transformers with OLTCs to control voltage levels and reactive power injection throughout the distribution grid. As there were few generating units in the distribution system, their impact on the reactive power was mitigated by imposing grid code policies (defined by the system operators) that must be strictly followed to avoid penalties. Note that reactive power injection/absorption has a direct impact on the voltage levels [24] making its control essential to maintain the security and quality of supply.

Typically, the reactive power policies designed by the DSOs are tailored for the inherent characteristics of the distribution systems they operate as well as the characteristics of the different types of generators, especially RES units. In Portugal, the reactive power energy policy at the distribution grid is based on the average of reactive power absorbed/injected by each generating unit in each single hour [25]. The cumulative reactive energy must be within a range of the tangent $\varphi$ ($\tan\varphi$), where $\tan\varphi$ is defined as the ratio between reactive and active power. The reactive power depends on the $\tan\varphi$, which is a function of the active power injected by the generating units into the grid. The $\tan\varphi$ varies according to the time of the day and must be met within a range of +/− 5%. While the day is typically classified into four periods (peak, full, valley and super valley), the periods for the reactive power policy only consider two classifications, which are the peak (peak and full hours) and the off-peak (valley and super valley) periods. In addition, there are two different schemes to classify different generating units connected to the distribution system: the ordinary and special schemes. The special scheme comprises all generating units that produce energy from RES, industrial and urban waste, cogeneration and micro-producers. In contrast, the ordinary scheme comprises the conventional units.

The relation between active and reactive power in the ordinary scheme for the peak period (from 7 am to 12 am) is $\tan\varphi = 0.4$, while $\tan\varphi = 0$ for off-peak hours (from 12 am to 7 am). In the special scheme, the relation between active and reactive power is in accordance to Table 1 [25]. Both schemes comprise the reactive power flexibility range (+/− 5%) of the $\tan\varphi$.

At the TSO-DSO connection point, the DSO must maintain the reactive power within a specific range imposed by the TSO, otherwise a penalty for violating the limits is applied to the DSO. More precisely, the $\tan\varphi$ must be kept within −0.3 and 0.3. The penalties are modeled through steps of $\tan\varphi$ infringement for peak hours. Currently, the violation of the limits of the inductive reactive power concerns three steps penalties shown in

**Table 2**
Reactive power penalties.

| Step | $\tan\varphi$ | Penalty factor |
|---|---|---|
| 1 | $0.3 \leq \tan\varphi < 0.4$ | 0.33 |
| 2 | $0.4 \leq \tan\varphi < 0.5$ | 1 |
| 3 | $0.5 \geq \tan\varphi$ | 3 |

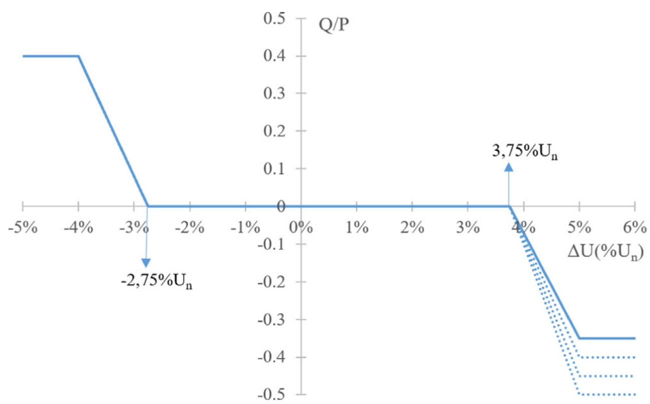


**Fig. 1.** Reactive power regulation scheme in France — $Q = f(U)$ [24].

Table 2 [26,27]. For each step, a penalty factor is multiplied by the reference price defined by the regulation entity.

In France, the reactive power policy comprises two different schemes for DERs depending on their characteristics. The first scheme considers the use of a fixed $\tan\varphi$ with specific lower and upper limits defined in [28]. The $\tan\varphi$ varies from producer to producer, according to the agreement established with the DSO when the generator is connected to the grid [28]. The DSO evaluates the needs of reactive power at the connection node and sets a fixed $\tan\varphi$ that should be met within the predefined lower and upper limits by the generating unit at any time. The DSO can set any fixed $\tan\varphi$ from the range $-0.35$ to 0.4, and in case of generator being able to reach $-0.5$, the DSO can set the fixed $\tan\varphi$ within the range of $-0.5$ to 0.4. The second scheme defines that the reactive power injection/absorbing is determined through a function depending on the deviation of voltage at the node of the generating unit [28,29]. That is, the reactive power injected/absorbed by the generating unit is adjusted according to the deviation in percentage between the nominal and measured voltage at the connection point as shown in Fig. 1 [29]. In case of negative voltage deviation, namely, less than $-2.75\%U_n$, reactive power is injected. Otherwise, the generator absorbs reactive power in the case of a positive voltage deviation, greater than $3.75\%U_n$.

The main differences between the Portuguese and French policies rely on the establishment of reactive power values. In the Portuguese case, the reactive power comes as a function of the active power through the establishment of $\tan\varphi$. In the French case, on the other hand, a case-by-case study is carried out at each connection point, where a fixed reactive power value $Q$ or a function of the voltage $Q = f(U)$ is established at the moment of the connection agreement.

### 2.2. Future reactive power management

Current reactive power policies do not fully consider the characteristics and flexibility of DER, especially RES units, which bring uncertain and variable active power production. In this scope, the current practices for reactive power management are no longer 100% adapted to the distribution system with high levels of variable production, and therefore must be adapted to include new ways of addressing this problem. One way is to introduce a new type of reactive power flexibility contracts allowing the DSO to use a reactive power band (upward[1] and downward[2] reactive power flexibility) from each generating unit within its technical capabilities. The DSO is, therefore, able to set a new reactive operating point for the DER unit, which can come in the form of $\tan\varphi$ or a $Q$ value. This new reactive power flexibility is described and modeled in this study, allowing the DSO to take advantage of DER for purposes of reactive power management. Note that the new reactive power flexibility is inspired on the Portuguese and French reactive power policies, but cannot be directly applied to them, i.e., it requires specific adaptations to be integrated in the Portuguese or French policies.

Recent developments in wind turbines and PV panels brought the ability to control the active and reactive power production, to some extent. In fact, [30] have proven that RES can provide reactive power flexibility within a range limit considering acceptable levels of accuracy. Such provision reinforces the use of optimization and management methodologies able to cope with the uncertain RES production. Thus, the use of DER to assist in the reactive power management of the DSO is a possibility that must be taken into account.

In this context, a new approach for solving the reactive power management problem under RES forecast uncertainty and provide the service to the TSO is illustrated in Fig. 2. The methodology is based on a two-stage stochastic programming model based on an OPF model, considering grid and resources constraints. The aim is to allow the DSO to provide a reactive power service to the TSO, by contracting reactive power flexibility to the DER in advance of the operating stage. Thus, the model is divided into two stages.

In the first stage, the DSO books upward and downward reactive power flexibility to be used during the operating stage. The upward and downward reactive power flexibility stands for an increase or decrease from the expected reactive operating point of the DER, either at inductive or capacity operating point.

Note that the generating units under a standard reactive power policy are not available for participating in the service. Thus, the upward and downward reactive power flexibility are zero for these units. Still, in this stage, the DSO can request the change of the reactive power policy to the DER (at a certain cost), to overcome potential reactive power needs. In this case, the full technical capabilities of the generating units for upward and downward reactive power flexibility are considered. Despite these assumptions, generating units are remunerated (as long as scheduled) for the capacity of providing a modification to their reactive power operating point [31]. The first-stage is performed one day-ahead of the operating stage.

In real-time (second stage), the reactive power flexibility booked in the day-ahead stage is activated depending on the system needs, which are scenario dependent. The DSO only activates the reactive power flexibility from the DER after determining the convenient set points of its internal resources (such as, transformers and capacitor banks). It is assumed that the DSO has manual control of the OLTC of transformers, which is not applied to the French case since the control is made by setting the voltage set point at the MV bus bar of the HV/MV power transformer (secondary winding). As a standard policy, a fixed $\tan\varphi$ has been set for every DER with a $+/-$ 5% flexible band (i.e., the DER

[1] Upward reactive power flexibility means the increase of reactive power injected in the network or the reduction of the reactive power absorbed by the network.

[2] Downward reactive power flexibility means the reduction of reactive power injected in the network or the increase of the reactive power absorbed by the network.

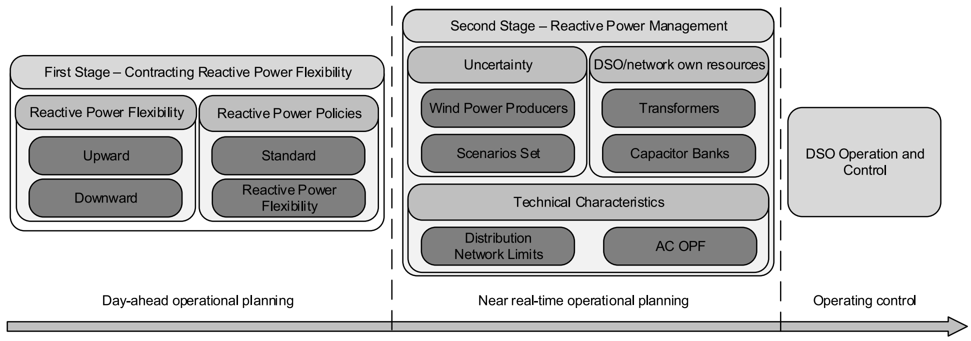


**Fig. 2.** Preventive reactive power management.

can operate within this range). However, it is assumed in the present methodology that the DSO determines the optimal point within that range, which promptly sends to the DER. In case a new operating point outside the boundaries is required, then the new reactive power flexibility policy is used. In this case, the DSO determines the new operating point of reactive power considering the full technical limits of the DER. The DSO requires this new operating point to the DER and is willing to pay significant higher fee. Notwithstanding, the DSO may activate any contract with generating units, as long as it is required for managing the reactive power in the distribution system at minimum cost.

## 3. Methodology

The optimization methodology proposed is based on a two-stage stochastic programming to cope with the uncertain behavior of RES and to solve the reactive power management in a distribution grid. The problem aims to minimize the operating cost of the DSO by contracting reactive power flexibility in the first-stage to be used during the operating stage. The DSO contracts reactive power from DER with the expectation to cope with the uncertain behavior of RES and the reactive power needs of the distribution system, under the limits requested by the TSO in the connections points with the distribution grid. Therefore, the DSO is ready to face the uncertain reactive power production of RES, as well as the limits requested by the TSO. The DSO can measure the active and reactive power exchanged in the TSO/DSO connection point, as well as the active and reactive power of DER with an installed capacity greater than 1 MW.

### 3.1. Objective function

The reactive power management problem is modeled as a mixed-integer nonlinear optimization problem, since it considers a full AC-OPF for a single period. It is assumed that the minimum daily operating cost is obtained by the minimum cost in each single period. The objective function (1) includes two parts, in which the first part ($F^{DA}$) is related to the first-stage problem, while the second part ($F^{RT}$) represents the second stage considering the realization of the scenarios. Hence,

$$\min \quad F^{DA} + F^{RT}, \tag{1}$$

in which $F^{DA}$ stands for the contracting of reactive power flexibility in the first-stage decision. The first-stage part of the objective function is modeled as

$$\begin{aligned} F^{DA} = {} & \sum_{g=1}^{N_G} \left( C^{Q,UP}_{DER(g)} R^{Q,UP}_{DER(g)} + C^{Q,DW}_{DER(g)} R^{Q,DW}_{DER(g)} + X^{policy}_{DER(g)} C^{policy}_{DER(g)} \right) \\ & + \sum_{su=1}^{N_{SU}} \left( p^{Q,UP}_{TSO} RLX^{Q,UP}_{TSO} + p^{Q,DW}_{TSO} RLX^{Q,DW}_{TSO} \right), \end{aligned} \tag{1.1}$$

in which DER provide upward and downward reactive power flexibility under a specific cost. This cost, is assumed that is constant in all the periods of optimization. Furthermore, the DSO can change the policy for reactive power provision from DER. $X^{policy}$ is a binary variable stating if a new policy is applied or not depending on the system needs for reactive power. When the new policy is applied to a certain generator, this is now forced to operate in a different $\tan\varphi$ range. In addition, a mathematical relaxation (represented by $RLX$) of the $Q$ value requested by the TSO is assumed under a penalty. This mathematical relaxation is used to model the allowable $+/-$ 5% deviation from the requested $Q$ value at the TSO-DSO connection point.

The function $F^{RT}$ stands for the recourse function (second stage) of the objective function. The second-stage part of the objective function, represented in (1) by the recourse function $F^{RT}$,

$$\begin{aligned} F^{RT} = {} & \sum_{\omega=1}^{\Omega} \pi_{(\omega)} \\ & \times \left[ \begin{aligned} & \sum_{g=1}^{N_G} \left( C^{act,UP}_{DER(g)} r^{Q,UP}_{DER(g,\omega)} - C^{act,DW}_{DER(g)} r^{Q,DW}_{DER(g,\omega)} + C^{cut}_{DER(g)} P^{cut}_{DER(g,\omega)} \right) + \\ & p^{act}_{TSO} \left( rlx^{Q,UP}_{TSO(\omega)} - rlx^{Q,DW}_{TSO(\omega)} \right) + p^{Extra}_{TSO} rlx^{Extra}_{TSO(\omega)} + \sum_{l=1}^{N_L} \left( C^{Cut}_{(l)} P^{Cut}_{(l,\omega)} \right) + \\ & \sum_{cb=1}^{N_{CB}} \sum_{lv=1}^{N_{levels}} C_{CB(cb)} Z_{CB(cb,\omega,lv)} + \sum_{trf=1}^{N_{TRF}} \sum_{lv=1}^{N_{levels}} C_{TRF(trf)} Z_{TRF(trf,\omega,lv)} \end{aligned} \right] \end{aligned} \tag{1.2}$$

considers the cost of operating the distribution system in real-time, taking into account the realization of each of the scenarios under a given probability. Hence, where generators change their reactive power operating point at an activation price. Generation curtailment power is available at a greater cost to solve situations in which the active power produced by the generators is creating technical violations in the distribution grid. Alternatively, load curtailment (energy not supplied) is also considered, allowing the DSO to decrease the active power consumption at a higher cost (penalization), and therefore the reactive power consumption. The cost of the curtailment of generation and consumption should be greater than the penalties for relaxing the TSO request. Thus, the DSO will always prioritize the DER and consumers, instead of providing the reactive power service to the TSO. The OLTC capability of transformers (not applied in the French case) and capacitor banks are also considered in the problem formulation. The change in the tap is associated with a cost that considers the degradation in the equipment lifetime when changing the set point [32]. In the case of a greater need of reactive power flexibility (when the DSO cannot entirely provide the service), a different relaxation is activated through the variable $rlx^{Extra}$, allowing the DSO to provide part of the TSO request. The variable $rlx^{Extra}$ represents the difference between the reactive power set-point requested by the TSO and the operation point that the DSO can achieve without creating technical violations in the distribution system.

### 3.2. First-stage constraints

The first-stage constraints comprise the ones that are not dependent of the uncertainty, like the minimum and maximum bounds of the DER for provision of reactive power flexibility. Thus, the boundaries of contracted upward and downward reactive power flexibility offered by DER are represented by (2.1) and (2.2), respectively,

$$R^{Q,UP,Min}_{DER(g)} \leq R^{Q,UP}_{DER(g)} \leq R^{Q,UP,Max}_{DER(g)}, \quad \forall g \in \{1,\dots,N_G\} \tag{2.1}$$

$$R^{Q,DW,Min}_{DER(g)} \leq R^{Q,DW}_{DER(g)} \leq R^{Q,DW,Max}_{DER(g)}, \quad \forall g \in \{1,\dots,N_G\}. \tag{2.2}$$

Similar constraints are also applied to the mathematical relaxation variable $rlx^{Extra}_{TSO}$ of the reactive power at the TSO-DSO connection point allowing the problem feasibility in case of lack of reactive power flexibilities.

### 3.3. Second-stage constraints

The second-stage constraints comprise the ones associated with the uncertainty. The active power of the DER is related with the operating point that they have from the energy schedule. The operating point for RES is assumed to be fixed taking the value of the conditional mean forecast for active power generation. Therefore, the curtailment of active power in the operating stage is limited by

$$P^{cut}_{DER(g,\omega)} \leq P^{op}_{DER(g)} + \Delta P_{DER(g,\omega)}, \quad \forall g \in \{1,\dots,N_G\}, \quad \forall \omega \in \{1,\dots,\Omega\} \tag{3.1}$$

in which $\Delta P$ is the difference of active power between the realization scenario and the expected forecast in each scenario. It is worth mentioning that $\Delta P$ is zero for conventional DERs, since these resources are assumed to be fully-controllable disregarding any uncertainty in their production.

On the other hand, the energy flowing through TSO/DSO connection is limited by the contracts in the TSO/DSO boundaries and, ultimately, by the transformer's capacity at the primary substation. In terms of active power, it is assumed that, from time to time, the TSO can inject or absorb active power, thus being limited by its maximum capacity of injecting or absorbing active power in the distribution network.

$$-P^{Max}_{TSO(\omega)} \leq P_{TSO(\omega)} \leq P^{Max}_{TSO(\omega)}, \quad \forall \omega \in \{1,\dots,\Omega\}. \tag{3.2}$$

In addition, the second-stage also includes the bounds of the second-stage variables and the non-anticipativity constraints. The non-anticipativity constraints relate both first-stage and second-stage variables for upward and downward flexibilities of DER. More precisely, the activation of the reactive power flexibility is constrained by the contracted reactive power flexibility, thus

$$0 \leq r^{Q,UP}_{DER(g,\omega)} X^{NS}_{DER(g,\omega)} \leq R^{Q,UP}_{DER(g)}, \quad \forall g \in \{1,\dots,N_G\}, \quad \forall \omega \in \{1,\dots,\Omega\} \tag{3.3}$$

$$0 \leq r^{Q,DW}_{DER(g,\omega)} \left(1 - X^{NS}_{DER(g,\omega)}\right) \leq R^{Q,DW}_{DER(g)}, \quad \forall g \in \{1,\dots,N_G\}, \quad \forall \omega \in \{1,\dots,\Omega\}. \tag{3.4}$$

Constraints (3.3) and (3.4) are also applied to the mathematical relaxation represented through external suppliers. The ability for all generators to provide inductive/capacitive reactive power is also assumed. In this scope and for the sake of simplicity, it is assumed that all DERs can provide reactive power under a specific range constrained by the $\tan\varphi$ of the active power produced by the generator. This represents a simplification of the full spectrum diagram that relates $P$ and $Q$ for the DER. Thus, Eqs. (3.5) and (3.6) model the reactive power flexibility from the DER. Hence,

$$\begin{aligned}&\left(-\left(P^{op}_{DER(g)} + \Delta P_{DER(g,\omega)} - P^{cut}_{DER(g,\omega)}\right)\tan^{standard}\varphi\right)\left(1 - X^{policy}_{DER(g)}\right)\\ &\leq Q^{op}_{DER(g)} + r^{Q,UP}_{DER(g,\omega)} - r^{Q,DW}_{DER(g,\omega)} \leq\\ &\left(\left(P^{op}_{DER(g)} + \Delta P_{DER(g,\omega)} - P^{cut}_{DER(g,\omega)}\right)\tan^{standard}\varphi\right)\left(1 - X^{policy}_{DER(g)}\right),\\ &\forall g \in \{1,\dots,N_G\}, \forall \omega \in \{1,\dots,\Omega\}\end{aligned} \tag{3.5}$$

$$\begin{aligned}&\left(-\left(P^{op}_{DER(g)} + \Delta P_{DER(g,\omega)} - P^{cut}_{DER(g,\omega)}\right)\tan^{policy}\varphi\right)X^{new}_{DER(g)}\\ &\leq Q^{op}_{DER(g)} + r^{Q,UP}_{DER(g,\omega)} - r^{Q,DW}_{DER(g,\omega)} \leq\\ &\left(\left(P^{op}_{DER(g)} + \Delta P_{DER(g,\omega)} - P^{cut}_{DER(g,\omega)}\right)\tan^{policy}\varphi\right)X^{new}_{DER(g)},\\ &\forall g \in \{1,\dots,N_G\}, \forall \omega \in \{1,\dots,\Omega\}\end{aligned} \tag{3.6}$$

in which (3.5) models the reactive power flexibility for the use of the standard reactive power flexibilities policy, while the model for the proposed reactive power policy is established through (3.6). $X^{policy}$ is a binary variable setting if the resource $g$ uses the standard ($X^{policy} = 0$) or the proposed ($X^{policy} = 1$) policy for reactive power flexibilities. This decision variable assists the DSO to activate the new proposed policy for a certain generator $g$ in a specific period as required. It worth mention that the proposed method assumes a single hour simulation, i.e., it overlooks the reactive power variability within the hour. Therefore, the value of the reactive power energy for each hour simulated is numerically equal to the value of the reactive power.

In contrast, the reactive power provision from external suppliers represents the TSO request, i.e., a fixed $Q$ value. Eqs. (3.7) and (3.8) give the upward and downward activation of the mathematical relaxation variable for external suppliers. This relaxation variable is intended to increase the robustness of the problem formulation by also providing information concerning the difference between the TSO reactive power request and the reactive power that the DSO can inject/absorb at the TSO/DSO boundary point. However, this mathematical flexibility has a high penalty, since the goal is to meet the TSO request.

$$0 \leq rlx^{Q,UP}_{TSO(\omega)} \leq RLX^{Q,UP}_{TSO}, \quad \forall \omega \in \{1,\dots,\Omega\} \tag{3.7}$$

$$0 \leq rlx^{Q,DW}_{TSO(\omega)} \leq RLX^{Q,DW}_{TSO}, \quad \forall \omega \in \{1,\dots,\Omega\}. \tag{3.8}$$

For all generators and TSO, the active and reactive power production is limited by the apparent power capacity of the DER and transformers at the substation (in the case of the external suppliers), respectively.

$$\begin{aligned}{S^{Max}_{DER(g,\omega)}}^2 &\geq \left(P^{op}_{DER(g)} + \Delta P_{DER(g,\omega)} - P^{cut}_{DER(g,\omega)}\right)^2\\ &+ \left(Q^{op}_{DER(g)} + r^{Q,UP}_{DER(g,\omega)} - r^{Q,DW}_{DER(g,\omega)}\right)^2,\\ &\forall g \in \{1,\dots,N_G\}, \forall \omega \in \{1,\dots,\Omega\}\end{aligned} \tag{3.9}$$

As the last resource to mitigate congestion and voltage problems, the DSO can use demand response, and this is constrained by

$$0 \leq P^{DR}_{L(l,\omega)} \leq P_{L(l)}, \quad \forall l \in \{1,\dots,N_L\}, \forall \omega \in \{1,\dots,\Omega\}. \tag{3.10}$$

Thus, the reactive power consumption depends on the actual active power consumption under a $\tan\varphi$, given by

$$Q_{L(l,\omega)} = \left(P_{L(l)} - P^{DR}_{L(l,\omega)}\right)\tan\varphi, \quad \forall l \in \{1,\dots,N_L\}, \quad \forall \omega \in \{1,\dots,\Omega\} \tag{3.11}$$

in which the $\tan\varphi$ can be settled at 0.4, like in [33]. In addition to the reactive power flexibility that generating units can provide to the DSO, the current assets in the DSO management are also considered. Particularly, capacitor banks and transformers with OLTC are modeled. Capacitor banks and transformers are located at the substations and are owned by the DSO, which knows their intrinsic characteristics. The capacitor banks are used to provide reactive power to the transformer. Usually, capacitor banks are modeled by levels of reactive power production, given by

$$Q_{CB(cb,\omega,lv)} = Q^{levels}_{CB(cb,lv)} X_{CB(cb,\omega,lv)}, \quad \forall cb \in \{1,\ldots,N_{CB}\}, \quad \forall\omega \in \{1,\ldots,\Omega\}, \forall lv \in \{1,\ldots,N_{levels}\} \tag{3.12}$$

$$\sum_{lv=1}^{N_{levels}} X_{CB(cb,\omega,lv)} = 1, \quad \forall cb \in \{1,\ldots,N_{CB}\}, \forall\omega \in \{1,\ldots,\Omega\}. \tag{3.13}$$

The objective function (1.2) considers the cost of changing the tap for capacitor banks. The cost is multiplied by $Z_{CB}$, which represents the linearization of the absolute function considering the difference between the tap selection in the present period with the previous one. Therefore, $Z_{CB}$ is constrained by

$$X^{t-1}_{CB(cb,\omega,lv)} - X_{CB(cb,\omega,lv)} \le Z_{CB(cb,\omega,lv)}, \tag{3.14}$$

$$X_{CB(cb,\omega,lv)} - X^{t-1}_{CB(cb,\omega,lv)} \le Z_{CB(cb,\omega,lv)}, \forall cb \in \{1,\ldots,N_{CB}\}, \forall\omega \in \{1,\ldots,\Omega\}, \forall lv \in \{1,\ldots,N_{levels}\}. \tag{3.15}$$

In parallel, transformers with OLTC ability assure voltage control in the substation. The OLTC constraints are modeled as

$$\Delta V_{TRF(trf,\omega,lv)} = V^{levels}_{TRF(trf,lv)} X_{TRF(trf,\omega,lv)}, \forall\omega \in \{1,\ldots,\Omega\}, \forall trf \in \{1,\ldots,N_{TRF}\}, \forall lv \in \{1,\ldots,N_{levels}\}, \tag{3.16}$$

$$\sum_{lv=1}^{N_{levels}} X_{TRF(trf,\omega,lv)} = 1, \tag{3.17}$$

$$V_{sb(\omega)} = V^{ref}_{sb(\omega)} + \sum_{lv=1}^{N_{levels}} \Delta V_{TRF(trf,\omega,lv)}, \quad \forall\omega \in \{1,\ldots,\Omega\}, \forall trf \in \{1,\ldots,N_{TRF}\} \tag{3.18}$$

in which $\Delta V_{TRF}$ represents the voltage level to be activated in the transformer by the DSO. $V^{levels}_{TRF}$ is a parameter representative of all possible taps of the transformer, and $X_{TRF}$ is the binary variable for selection of a unique tap level. $V^{ref}_{sb}$ is the reference of voltage magnitude at the substation before use of OLTC ability by the transformer, while the final voltage value at the substation is denoted by $V_{sb}$. In addition, the cost for changing the tap of the transformer is included in the objective function (1.2), where $Z_{TRF}$ is the linearization of the absolute function, similar to the capacitor banks. Thus, the constraints are

$$X^{t-1}_{TRF(trf,\omega,lv)} - X_{TRF(trf,\omega,lv)} \le Z_{TRF(trf,\omega,lv)}, \tag{3.19}$$

$$X_{TRF(trf,\omega,lv)} - X^{t-1}_{TRF(trf,\omega,lv)} \le Z_{TRF(trf,\omega,lv)}, \forall trf \in \{1,\ldots,N_{TRF}\}, \forall\omega \in \{1,\ldots,\Omega\}, \forall lv \in \{1,\ldots,N_{levels}\}. \tag{3.20}$$

Furthermore, a full AC OPF model is considered in the problem to characterize the power flow in a distribution grid. This includes the modeling of the active power balance in each bus as

$$\sum_{g=1}^{N_G} \left(P^{op,i}_{DER(g)} + \Delta P^{i}_{DER(g,\omega)} - P^{cut}_{DER(g,\omega)}\right) + P^{i}_{TSO} + \sum_{l=1}^{N_L} \left(P^{Cut,i}_{L(l,\omega)} - P^{i}_{L(l)}\right) = G_{ii} V^2_{i(\omega)} + V_{i(\omega)} \sum_{j\in TL^i} V_{j(\omega)} \left(G_{ij}\cos\theta_{ij(\omega)} + B_{ij}\sin\theta_{ij(\omega)}\right) \quad \forall i \in \{1,\ldots,N_{Bus}\}, \forall\omega \in \{1,\ldots,\Omega\}, \theta_{ij(\omega)} = \theta_{i(\omega)} - \theta_{j(\omega)} \tag{3.21}$$

where the energy balance between the active power produced by every type of energy resource and the load consumption is met. Additionally, the reactive power balance is given by

$$\sum_{g=1}^{N_G} \left(Q^{op,i}_{DER(g,\omega)} + r^{Q,UP,i}_{DER(g,\omega)} - r^{Q,DW,i}_{DER(g,\omega)}\right) - \sum_{l=1}^{N_L} Q^{i}_{L(l,s)} + \sum_{cb=1}^{N_{CB}} \sum_{lv=1}^{N_{levels}} Q^{i}_{CB(cb,\omega,lv)} + Q^{op,i}_{TSO(\omega)} + rlx^{Q,UP,i}_{TSO(\omega)} - rlx^{Q,DW,i}_{TSO(\omega)} + rlx^{Extra,i}_{TSO(\omega)} = V_{i(\omega)} \sum_{j\in TL^i} V_{j(\omega)} \left(G_{ij}\sin\theta_{ij(\omega)} - B_{ij}\cos\theta_{ij(\omega)}\right) - B_{ii} V^2_{i(\omega)} \quad \forall i \in \{1,\ldots,N_{Bus}\}, \forall\omega \in \{1,\ldots,\Omega\}, \theta_{ij(\omega)} = \theta_{i(\omega)} - \theta_{j(\omega)} \tag{3.22}$$

where the reactive power production of all energy resources including the capacitor banks and consumers are considered. It worth mentioning that generators can provide inductive and capacitive reactive power, i.e. generators can produce or consume reactive power, depending on the system needs. Complementary, the energy flowing through the distribution lines as well as power transformers has a thermal limit that should not be exceeded. Thus, the power flow through the distribution lines and power transformers in TSO/DSO connection point from bus $i$ to bus $j$, and vice-versa is constrained by

$$\left|\overline{V_{i(\omega)}}\left[\overline{y_{ij}}\,\overline{V_{ij(\omega)}} + \overline{y_{sh\,(i)}}\,\overline{V_{i(\omega)}}\right]^*\right| \le S^{Max}_{TL}, \quad \overline{V_{ij(\omega)}} = \overline{V_{i(\omega)}} - \overline{V_{j(\omega)}} \tag{3.23}$$

$$\left|\overline{V_{j(\omega)}}\left[\overline{y_{ij}}\,\overline{V_{ji(\omega)}} + \overline{y_{sh\,(j)}}\,\overline{V_{j(\omega)}}\right]^*\right| \le S^{Max}_{TL}, \quad \overline{V_{ji(\omega)}} = \overline{V_{j(\omega)}} - \overline{V_{i(\omega)}}. \quad \forall i,j \in \{1,\ldots,N_{Bus}\}, \forall\omega \in \{1,\ldots,\Omega\}, i \ne j \tag{3.24}$$

The voltage magnitude and phase angle must prevail within the minimum and maximum limits established by the DSO. In addition, it is assumed that the voltage magnitude and phase angle for the slack bus is fixed. Finally,

$$V^{i}_{Min} \le V_{i(\omega)} \le V^{i}_{Max}, \quad \forall\omega \in \{1,\ldots,\Omega\}. \tag{3.25}$$

$$\theta^{i}_{Min} \le \theta_{i(\omega)} \le \theta^{i}_{Max}, \quad \forall\omega \in \{1,\ldots,\Omega\} \tag{3.26}$$

in which the minimum and maximum voltage magnitude limits considered in this case are 0.95 and 1.05 p.u., respectively. The minimum and maximum voltage phase angle is $-\pi$ and $+\pi$, respectively. Bus 1 is the reference bus with fixed voltage magnitude and phase angle of 1 p.u. and 0, respectively.

## 4. Assessment of reactive power management

This section presents a case study illustrating the application of the developed model and its performance.

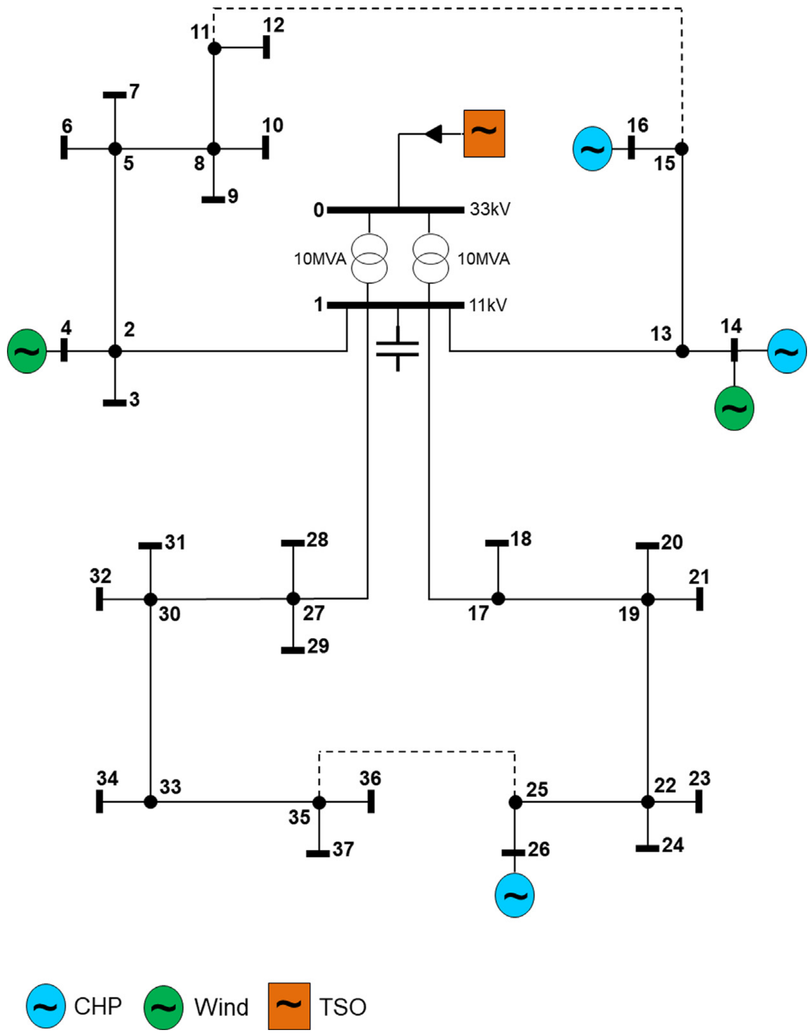


**Fig. 3.** 37-Bus distribution network.
*Source:* Adapted from [29].

## 4.1. Outline

The case study is based on a 37-bus distribution network (originally presented in [34]) adapted to support five DER, namely 3 CHPs and 2 wind turbines. Fig. 3 depicts the distribution network that is an underground network using Ø120 mm$^2$ MV cable, which is connected to a high voltage network through two power transformers of 10 MVA each. There are 22 consumption points distributed throughout the network. The consumption points consider 1908 consumers (1850 residential consumers, 2 industrial consumers, 50 commercial stores, and 6 service buildings) [34]. The consumption characteristics and profile are imported from [35], and therefore summarized in Table 3.

Two transformers and capacitor banks are considered in the network with the characteristics presented in Table 4. More precisely, the transformers have OLTC ability with maximum voltage deviation of 0.1 p.u. In addition, the capacitor banks also have tap-changing with a total capacity of reactive power production of 0.8 MVAr. The cost reflecting the use of the transformers and capacitor banks (with the OLTC ability that reduces the equipment lifetime) is determined based on [32], respectively. It is assumed that both equipment are owned and managed by the DSO.

The network comprises 3 CHPs and 2 wind turbines. All resources are able to provide reactive power flexibility, according to their technical limits. Following standard regulation, it is assumed

**Table 3**
Load characteristics.

| Load | Bus | Active power consumption $P_L$ (kW) | | |
|---|---|---|---|---|
| | | Min | Mean | Max |
| 1 | 3 | 373.2 | 677.9 | 1190.5 |
| 2 | 4 | 206.1 | 591.2 | 1015.6 |
| 3 | 6 | 88.4 | 599.0 | 1029.8 |
| 4 | 7 | 394.7 | 716.9 | 1259.1 |
| 5 | 9 | 539.0 | 761.8 | 1089.0 |
| 6 | 10 | 298.7 | 636.6 | 1040.9 |
| 7 | 12 | 323.0 | 586.5 | 1030.1 |
| 8 | 14 | 387.0 | 1110.4 | 1.9074 |
| 9 | 16 | 745.6 | 1589.1 | 2598.3 |
| 10 | 18 | 509.7 | 720.3 | 1029.8 |
| 11 | 20 | 88.4 | 599.0 | 1029.8 |
| 12 | 21 | 373.2 | 677.9 | 1190.5 |
| 13 | 23 | 365.1 | 778.1 | 1272.3 |
| 14 | 24 | 539.0 | 761.8 | 1089.0 |
| 15 | 26 | 323.0 | 586.5 | 1030.1 |
| 16 | 28 | 178.3 | 511.6 | 878.8 |
| 17 | 29 | 74.4 | 503.8 | 866.2 |
| 18 | 31 | 314.0 | 570.2 | 1001.4 |
| 19 | 32 | 290.4 | 618.9 | 1011.9 |
| 20 | 34 | 93.5 | 633.4 | 1089.0 |
| 21 | 36 | 217.9 | 625.3 | 1074.1 |
| 22 | 37 | 323.0 | 586.5 | 1030.1 |

**Table 4**
Transformer and capacitor bank characteristics.

| Equipment | Number of units | Number of tap-changing $N_{levels}$ | Tap-changing capacity $V_{TRF}^{levels}$, $Q_{CB}^{levels}$ | Cost$C_{TRF}$, $C_{CB}$ (m.u. per change) |
|---|---|---|---|---|
| Transformer | 2 | 21 | 0.1 p.u. | 0.19 |
| Capacitor Bank | 2 | 5 | 0.2 MVAr | 0.47 |

**Table 5**
General characteristics and operating point for DER.

| DER | Number of units | Total installed power | Operating point $P^{op}$ (MW) | | |
|---|---|---|---|---|---|
| | | | Min | Mean | Max |
| CHP | 3 | 2.5 (MVA) | 1.0 | 1.15 | 1.5 |
| Wind | 2 | 20 (MVA) | 11.31 | 14.01 | 15.34 |
| TSO | 1 | – | – | – | – |

**Table 6**
Reactive power cost.

| DER | Upward cost $C^{up}$(m.u./kVAr) | | | Downward cost $C^{dw}$(m.u./kVAr) | | | New policy cost $C^{policy}$ (m.u.) |
|---|---|---|---|---|---|---|---|
| | Min | Mean | Max | Min | Mean | Max | |
| CHP | 0.02 | 0.04 | 0.06 | 0.02 | 0.04 | 0.06 | 0.01 |
| Wind | 0.02 | 0.025 | 0.03 | 0.02 | 0.025 | 0.03 | 0.01 |
| TSO | 1 | 1 | 1 | 1 | 1 | 1 | – |

**Table 7**
DER activation and curtailment cost.

| DER | Activation cost $C^{act}$ (m.u./kVArh) | | | Curtailment $C^{cut}$/demand response $C_L^{DR}$ (m.u./kWh) |
|---|---|---|---|---|
| | Min | Mean | Max | |
| CHP | 0.01 | 0.02 | 0.03 | 10.0 |
| Wind | 0.01 | 0.13 | 0.15 | 10.0 |
| TSO | 0.5 | 0.5 | 0.5 | 10.0 |
| Load | – | – | – | 10.0 |

that the DER active power generation should be fully absorbed by the network. Therefore, Table 5 shows the generic characteristics of the DER, including the expected operating point (e.g., wind power forecast).

In addition, the cost for upward and downward reactive power flexibility is given in Table 6. The cost for changing the reactive power policy between the DSO and the DER is also included. This cost enables the DSO to change the standard policy ($\tan\varphi$) of each DER to a new policy considering a different $\tan\varphi$. The new $\tan\varphi$ level is enforced by the DSO, according to the DER technical limits.

Table 7 gives the activation cost of the reactive power flexibility for each type of technology. It also includes the curtailment cost for each type of DER, as well as the cost related to the use of demand response.

RES are modeled through stochastic variables. Thus, upward and downward reactive power flexibility is constrained by the upper and downward reactive power flexibility they offer to the DSO, and therefore by their technical limits. The uncertainty of wind power forecast is modeled in the form of scenarios over 24-hour periods, which can be found in [36,37]. A set of 10 scenarios for each different time-step and wind power generator were extracted from [37]. These scenarios are representative of the wind power distribution, and therefore, sufficient to test the methodology. In this case study, the standard reactive power policy of the DER are subjected to the Portuguese regulation, following Table 1.

At the TSO/DSO connection point, the TSO can establish the required reactive power to inject or absorb of the distribution grid. In this case, a time series of $Q$ values has been established, as shown in Table 8. It is important to mention that in the present study the transmission system is not analyzed and the proposed values are defined only to test the methodology to be used by the DSO.

**Table 8**
TSO request throughout 24 h in MVAr.

| hour | Q | hour | Q | hour | Q | hour | Q |
|---|---|---|---|---|---|---|---|
| 1 | 1.9527 | 7 | 1.2319 | 13 | 2.3057 | 19 | 2.9387 |
| 2 | 1.7911 | 8 | 1.5124 | 14 | 2.2661 | 20 | 3.2163 |
| 3 | 1.5520 | 9 | 1.8706 | 15 | 2.2404 | 21 | 3.1441 |
| 4 | 1.3429 | 10 | 2.1405 | 16 | 2.2539 | 22 | 2.9496 |
| 5 | 1.2264 | 11 | 2.2426 | 17 | 2.3603 | 23 | 2.6494 |
| 6 | 1.1073 | 12 | 2.3143 | 18 | 2.6624 | 24 | 2.3518 |

This test case was constructed assuming that active power from DER can be greater to or less than the load in the grid. Thus, the TSO can either inject or absorb active power depending on the realization of wind generation over time.

### 4.2. Results

Input and output data of this study are available at Mendeley Data. The input data about network topology, resistance and reactance of the lines, as well as active and reactive power consumption are included. The output data include active and reactive power generation, voltage magnitude and phase angle and active and reactive power flow in each line (http://dx.doi.org/10.17632/kwws76vxwr.1).

#### 4.2.1. Reactive power planning

As previously mentioned, the main goal of this methodology is to support the reactive power management activity of the DSO, allowing it to provide an additional service to the TSO. This management considers the reactive power needs of the grid, and the request from the TSO at the interface substation. Therefore, the DSO can activate the new reactive power policy with DER, allowing them to support reactive power (beyond

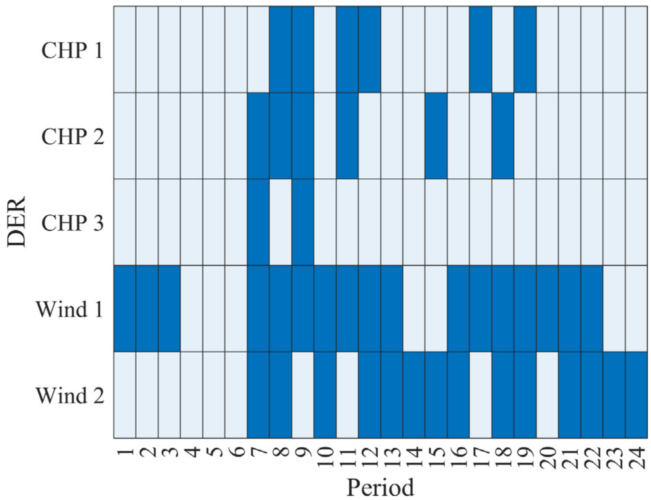


**Fig. 4.** Scheduling of new contract for reactive power provision by DER.

the standard regulatory framework), in case the internal DSO equipment (capacitor banks) is insufficient.

Thus, the tool optimally allocates each DER, taking into consideration the cost curve of each one, and the capacitor banks. Fig. 4 shows the potential activation of the new reactive power policy by the DSO to each DER throughout the day. The darkest color means that the DSO activates the new policy of a certain DER for that specific period, whereas the lightest color denotes that the DSO keeps the standard reactive power policy.

Note that both wind power plants are frequently required to change the tan $\varphi$ to values of the new policy. The expected tan $\varphi$ for all DER and period is depicted in Fig. 5, which shows the tan $\varphi$ whether the DSO activates or not the new policy. In the periods when the new policy is not activated (Fig. 4), the tan $\varphi$ of that generator (Fig. 5) is within the requirements of the standard reactive power policy with a possible deviation of $+/-$ 5%. Through this figure, the DSO has an estimate of the tan $\varphi$ of the DER that can be obtained under the standard or the new policy, accounting for $+/-$ 5% of allowable deviation. As expected, the wind power producers are the ones with greater volatility and changes in the policy (which occurs several times per day), since they are the cheapest generators after the capacitor banks.

It worth mention that the methodology relies first on capacitor banks capacities to cover the reactive power production, and then on the DER. In this test case, capacitor banks are allocated to their maximum reactive power production. Furthermore, it is worth mentioning that the Q value required by the TSO can be violated in case of insufficient reactive power capacity by the generators, or because it is not technically feasible. In such cases, the TSO requirement is relaxed, and the extra amount of scheduled reactive power is determined. In such case the DSO reports to the TSO the extra amount of reactive power that is required, i.e., the DSO only supports part of the actual TSO request.

The proposed tool provides a range of solutions for each resource, accounting for 10 scenarios. Each solution is indicative of the expected behavior of the resources when facing a certain expected wind power realization scenario. The tan $\varphi$ of each wind power producer in each scenario throughout the day is depicted in Figs. 6 and 7, respectively. One can observe through Figs. 6 and 7 that the reactive power provision slightly varies from scenario to scenario in most of the periods. In the first periods, the wind power producer 1 (Fig. 6) provides more reactive power to the system than wind power producer 2 (Fig. 7), since a new policy was assigned. In the remaining periods, both wind power producers present similar patterns of reactive power provision, since they are the cheapest DER to provide the extra reactive power needs.

**Table 9**
Service cost to the DSO throughout 24 h in m.u.

| hour | Cost | hour | Cost | hour | Cost | hour | Cost |
|---|---|---|---|---|---|---|---|
| 1 | 0.0487 | 7 | 0.3560 | 13 | 2.2434 | 19 | 0.4027 |
| 2 | 0.0439 | 8 | 1.5101 | 14 | 0.5671 | 20 | 0.7549 |
| 3 | 0.0371 | 9 | 0.3650 | 15 | 0.4118 | 21 | 3.3724 |
| 4 | 0.7710 | 10 | 0.9397 | 16 | 0.5275 | 22 | 3.3827 |
| 5 | 0.0213 | 11 | 1.1094 | 17 | 0.4399 | 23 | 0.5696 |
| 6 | 0.0161 | 12 | 1.6527 | 18 | 0.3977 | 24 | 2.1859 |

Nevertheless, the aim of this tool is to provide an answer of the service to the TSO. In this case, the DSO replies with success to the TSO. That is, the DSO is able to control/contract sufficient reactive power flexibility from capacitor banks and DER to meet the TSO request of reactive power in every hour. Though the request is fully met, there might be cases in which the DSO cannot entirely provide the request and, therefore, the tool will reply with the amount of Q that the DSO can support. The cost the TSO should pay for the service in each hour is given in Table 9. Note that cost varies with the use of the resources and activation of reactive power flexibilities. Also, the costs and remuneration schemes of DERs services are defined by regulatory agencies and are adjusted almost every year. It is also important to mention that costs used on the present work are indicative and further studies adapted to the reality of each DSO should be conducted to better define these values. These costs can be determined by approaches similar to those found in [38,39].

#### *4.2.2. Computational performance*

Simulations have been carried out with MATLAB and GAMS. MATLAB has been used as an interface for handling data with GAMS, while GAMS performed and solved the mixed integer nonlinear programming problem using the DICOPT solver [40]. The computations were carried on an Intel Xeon E3-1245 3.50 GHz processor with 32 GB RAM. The average computational effort and operational costs of the tool for the case study presented are depicted in Fig. 8. One can see that the computational effort, which is measured in seconds, experiences an exponential growth trend with an increasing number of scenarios. In contrast, the operational costs tend to decrease with the number of scenarios. This is justified by the representativeness of the scenarios in each set of scenarios. With the increase in the number of scenarios, extreme scenarios have less impact on the decision-making, resulting in lower requirements of reactive power flexibility. The optimal number of scenarios can be studied case by case considering, on the one hand, the network size and its energy resources and, on the other hand, the available computational resources.

It should be pointed out that, for this case study, the proposed method is able to provide a solution to the DSO within the time limit. However, with the increasing of the number of scenarios and renewable sources, the computational effort can grows significantly, which constrains the provision of the optimal solution to the DSO. In such cases, different approaches must be studied to reduce the computational effort. Such approaches can either reduce the computational effort or the solution accuracy and will be considered in a future work.

One way to reduce computational effort is by linearizing nonlinearities in the modeling, making it convex. For instance, AC-OPF convex relaxations (discussed in depth in [41,42]) such as the second-order cone programming and semidefinite programming can be implemented. Such approach, however, only provides approximate solutions to the nonlinear solution. Another way

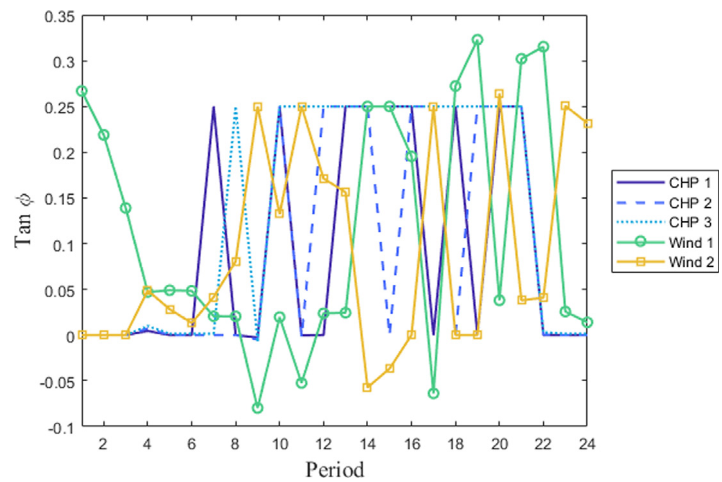


**Fig. 5.** Expected $\tan\varphi$ of each DER throughout the day.

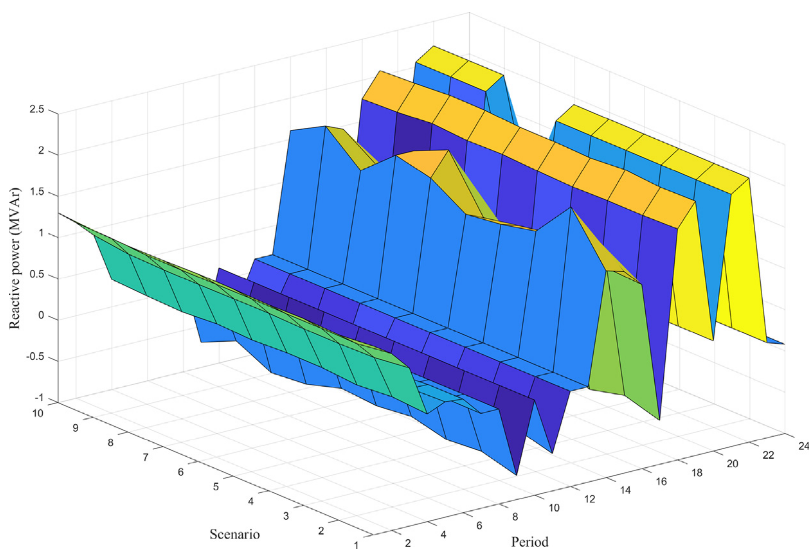


**Fig. 6.** Reactive power production by scenario and period for wind power plant 1.

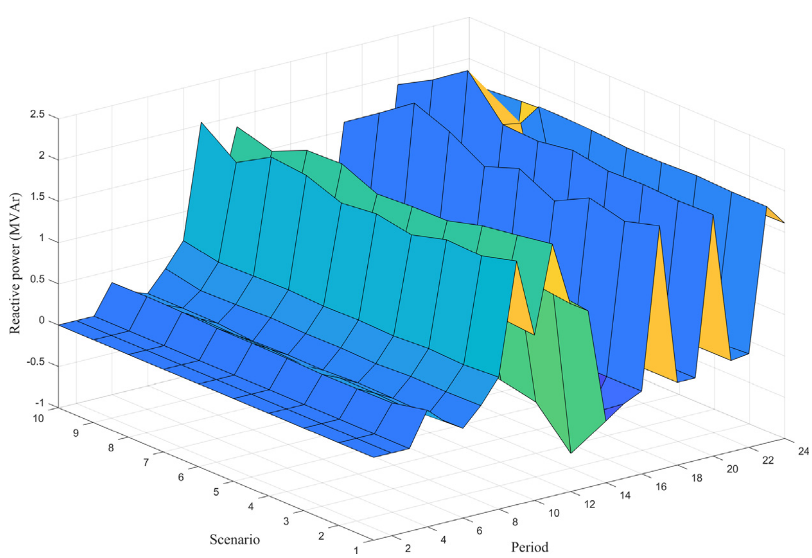


**Fig. 7.** Reactive power production by scenario and period for wind power plant 2.

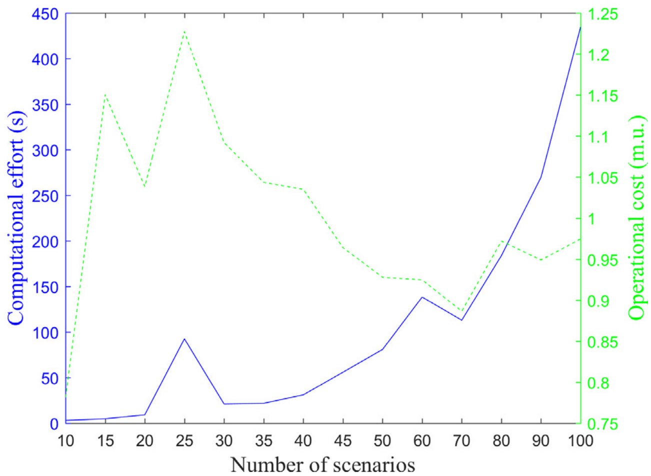


**Fig. 8.** Average computational effort and operational cost for different number of scenarios.

is to select representative scenarios for simulation. Clustering techniques can be used to find the most representative set of scenarios and underlying probabilities of the system [43]. In this way, the number of scenarios can be significantly reduced from the initial set of scenarios, leading to a reduction in the number of variables, thus requiring less computational effort. Nevertheless, the combination of aforementioned approaches is the most likely evolution for the proposed methodology.

In the proposed approach, aggregators of small energy sources (such as home battery systems and small PV systems) are disregarded, as the model is directed to be run on MV networks. Still, the role of the aggregator can be added and represented in the model as an independent energy resource with aggregated reactive power flexibility and costs by node of the MV network. In this way, the intermediary role of the aggregator is preserved and integrated in the system.

## 5. Conclusions

This work proposes a new tool for reactive power management by the DSO considering the reactive power flexibility that can be provided by the DER. This tool allows the DSO to provide reactive power service to the TSO at a certain cost, which can be used as an alternative to investments in reactive power control equipment in the transmission network. It is also assumed that the DSO is able to change the standard reactive power policies of each DER at a given cost. Changing to the new policy allows the DSO to establish a new reactive operating point for the DER (or a range of reactive power operation) concerning their technical limits.

Simulation results for a 37-bus test distribution network demonstrate the feasibility of the proposed tool to provide the service to the TSO. To this end, the tool defines the capacitor banks level and selects the DER that should provide reactive power flexibility under different operating conditions to support the service. The results show wind power producers are the generators with higher volatility in changing between the standard and the proposed scheme, since they are the cheapest DER to provide reactive power and the first to enter in service. In addition, the results show that the tool enables a fast and reliable support to the decision-making process of the DSO upon a reactive power flexibility request by the TSO while allowing the definition of the least cost for supplying the service.

Future work may include simulations of the developed tool considering different distribution grids, aiming to test its replicability and scalability in dissimilar contexts. The methodology proposed only considers wind power uncertainty as this is the main source of uncertainty identified by the partners of TDX-ASSIST project in the distribution networks analyzed. Note that the method can be easily modified to include the uncertainties of other DER and consumption. In this case, the scenarios used to model extra layers of uncertainty need to take into account the spatiotemporal dependence between the stochastic resources available in the network.

## 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.

## CRediT authorship contribution statement

**Tiago Soares:** Conceptualization, Software, Validation, Writing - original draft, Writing - review & editing, Visualization. **Leonel Carvalho:** Conceptualization, Validation, Writing - original draft, Writing - review & editing. **Hugo Morais:** Conceptualization, Validation, Writing - original draft, Writing - review & editing. **Ricardo J. Bessa:** Conceptualization, Resources, Writing - review & editing. **Tiago Abreu:** Conceptualization, Validation, Writing - review & editing, Visualization. **Eric Lambert:** Conceptualization, Funding acquisition, Supervision, Resources.

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