Reactive Power Provision by the DSO to the TSO considering Renewable Energy Sources Uncertainty

Tiago Soares[1*], Leonel Carvalho[1], Hugo Morais[2,3], Ricardo J. Bessa[1], Tiago Abreu[1] and Eric Lambert[2]

[1] INESC TEC - INESC Technology and Science, 4200-465 Porto, Portugal; tiago.a.soares@inesctec.pt (TS), leonel.m.carvalho@inesctec.pt (LC), tiago.j.abreu@inesctec.pt (TA)

[2] EDF; 75010 Paris, France; eric.lambert@edf.fr (EL)

[3] IST; 1049-001 Lisbon, Portugal; hugo.morais@tecnico.ulisboa.pt (HM)

** Correspondence: tiago.a.soares@inesctec.pt*

ABSTRACT

The current coordination between the transmission system operator (TSO) and the distribution system operator (DSO) is changing mainly motivated by the continuous integration of distributed energy resources (DER). The DER technologies are able to provide reactive power services helping the DSOs and TSOs in 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 reactive power services to the TSO. The proposed method entails the use of a stochastic AC-OPF, ensuring reliable solutions for the DSO. RES forecast uncertainty is modeled by a set of spatial-temporal trajectories. A 37-bus distribution grid considering realistic generation and consumption data is used to validate the proposed method. An important conclusion is that the method allows the DSO to take advantage of DER full capabilities to provide a new service to the TSO.

KEYWORDS: Decision-aid; distributed energy resources; distribution system operator; reactive power management; uncertainty.

Nomenclature

Parameters

ΔP	Power deviation in each scenario ω
B	Imaginary part in admittance matrix
C	Cost
G	Real part in admittance matrix
N	Number of unit resources
p	Penalty for external supplier's flexibility
T	Time horizon
$\bar{y}$	Series admittance of line that connects two l
$\bar{y}_{sh}$	Shunt admittance of line that connects two b

Variables

θ	Voltage angle
P	Active power
Q	Reactive power
r	Reactive power flexibility used in the operat
rlx	Reactive power relaxation in the operating s
R	Reactive power flexibility contracted at day-
RLX	Reactive power relaxation at day-ahead stag
S	Apparent power
V	Voltage magnitude
$\bar{V}$	Voltage in polar form
V_{sb}	Voltage at slack bus
ΔV	Voltage level activated by the DSO in the tr
X	Binary variable
Z	Auxiliary variable for absolute function line

Subscripts

ω	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 ba 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 stag
cut	Generation curtailment power for energy res
Max	Maximum limit
Min	Minimum limit
new	Proposed reactive power policy
op	Operating point of the power resource
Q,DW	Downward reactive power flexibility
Q,UP	Upward reactive power flexibility
DR	Demand response of consumer l
$standard$	Standard reactive power policies

1. Introduction

The distribution grid has been continuously evolving, especially with the deployment of DER, mainly RES. Operating a distribution grid considering 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 active/preventive behavior of DSOs, by contracting/controlling DER flexibilities to solve potential congestion and voltage problems [2].

The traditional and new methods 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/proactive management methods may be compatible with the conventional network management in a way that complement 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 considering the inclusion of forecast in operational planning tools and doing contracts to reduce network operating problems [4]. DERs can contribute to solve congestion and voltage problems by providing flexibility to change 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 network access to all users (consumers and producers) with proper levels of security, safety and stability, as well as the required service quality [6].

This management allows the coordination between TSOs and DSOs in order to avoid voltage constraints in transmission and distribution systems. To this end, proactive reactive power management in the distribution grid is essential, especially given the important role played by DERs. 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, preventive reactive power management methodologies 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 strong 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] by using a linearization of the nonconvex nonlinear AC OPF problem through second-order cone programming. On top of this, [12,13] implement and compare the two-stage stochastic and robust approaches. It decomposes and solves the second-stage problem in several sub-problems through column-and-constraint generation algorithm method. In contrast, [14] models an active and reactive power management considering an complete AC OPF with individual and independent offers for active and reactive power support. Similarly, an linear active and reactive power management based on unit commitment problem is proposed in [15]. The reactive power management is limited to the provision of reactive power from generating units, disregarding the use of static equipment's. A stochastic algorithm for reactive power dispatch is proposed by [16]. The methodology is based on a sequential procedure where a linear deterministic reactive power dispatch is solved considering point-estimated method for wind generation, and then the solution is validated for network constraints through the Gauss-Seidel method. A two-stage stochastic corrective voltage control model is addressed 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. A stochastic voltage and reactive power control is modeled by [18], based on sampling from a sequence of probability distributions of all possible settings of transformers with on-load tap-changer (OLTC) and capacitor banks. A discrete-time stochastic process is proposed by [19] to deal with the uncertain production of PV units on a decentralized and full linearized active and reactive power control. While [20] proposes a stochastic multi-objective reactive power dispatch, the costs for contracting reactive power in advance of the operating stage are disregarded, being the reactive power dispatch only dependent of the active power operating costs.

Most of these works rely on linear approximations of the AC OPF to ensure optimality, however, the set of feasible convex solutions deviate from solutions of the original problem. Thus, the accuracy of modelling the real behavior of distribution systems is skewed and non-optimal.

In this context, this work proposes a 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. The model addresses an innovative trend of procuring 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 considering the assumption that the DSO can have specific contracts with DER to control the reactive power in case of network constraints. 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 propose a distinct model for supporting the DSO reactive power management under uncertain and variable power production, considering the use of reactive power flexibilities;
- To model a local reactive power service to be provided by the DSO to meet TSO needs in advance of the operating stage;
- To improve the full AC OPF tool developed by [21], adding stochastic optimization to cope with RES power forecast uncertainty;
- To analyze and compare different types of flexibility contracts considering the present policies in Portugal and France.

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

2. Framework for Reactive Power Management

2.1. Current Reactive Power Policies

Typically, DSOs use static equipment's (e.g. transformers with OLTC and capacitor banks) for controlling voltage levels and reactive power injection throughout the distribution grid. As generating units were not so present in the distribution system their impact on the reactive power was mitigated by imposing grid code policies (defined by the system operators) which generating units must follow to avoid penalties. Note that reactive power injection/absorbing has a direct impact on the voltage levels [22], and therefore their control is essential to maintain the security and quality of supply.

The reactive power policies designed by the DSOs concerns the inherent characteristics of their distribution system, as well as the characteristics of the different types of generators, especially RES units.

In Portugal, the reactive power policy at the distribution grid is based on the summation of inductive and capacitive reactive energy produced by a generating unit in one single hour [23]. The cumulative reactive energy must be within a range of the $tan\ \phi$. The reactive power depends on the $tan\ \phi$ in function of the active power injected by the generating units into the grid. The $tan\ \phi$ varies according to the time of the day and must be met within a range of +/- 5%. The day is classified in four periods, namely (peak, full, valley and super valley). However, the periods for the reactive power policy consider only two classifications, which are peak (peak and full hours) and off-peak (valley and super valley). 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 energy in the ordinary scheme for the peak period (from 7 am to 12 am) has *tan* ϕ=0.4, while *tan* ϕ=0 for off-peak hours (from 12 am to 7 am). In the special scheme, the relation between active and reactive energy is in accordance to Table I [23]. Both schemes comprise the flexibility range (+/- 5%) of the *tan* ϕ.

Table I: Reactive power policy for the special scheme.

Voltage level	*tan* ϕ	
	Peak period	*Off-peak period*
HV	0	0
MV (P>6MW)	0	0
MV (P≤6MW)	0.3	0
LV	0	0

At the upstream connection, the DSO must maintain the reactive energy within a specific range imposed by the TSO, otherwise a penalty for violating the limits is applied to the DSO. More precisely, the *tan* ϕ must be kept within -0.3 and 0.3. The penalties are modeled through steps of *tan* ϕ infringement for peak hours. Currently, the violation of the limits of the inductive reactive power concerns three steps penalties [24,25]:

- $0.3 \leq tan\ \phi < 0.4$;
- $0.4 \leq tan\ \phi < 0.5$;
- $0.5 \leq tan\ \phi$

where the first step has a penalty factor in the cost of 0.33, the second set has a penalty factor of 1, and the third a factor of 3.

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* ϕ with specific lower and upper limits defined in [26]. The *tan* ϕ varies from producer to producer, according to the agreement established with the DSO when the generator is connected to the grid [26]. The DSO evaluates the needs of reactive power at the connection node and sets a fixed *tan* ϕ 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* ϕ 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* ϕ 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 [26,27]. 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 Figure 1 [27].

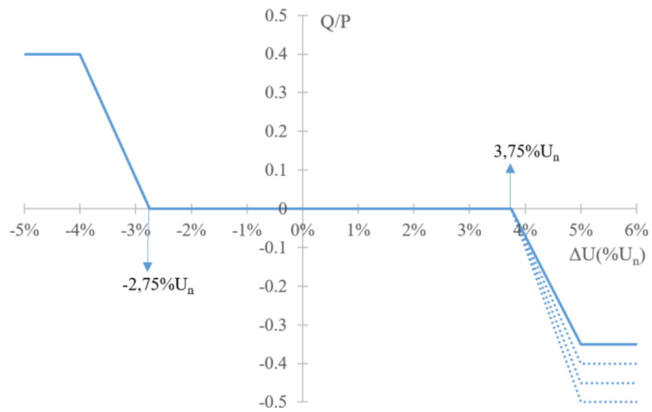

Fig. 1. Reactive power regulation scheme in France – Q=f(U) [24].

In case of negative voltage deviation, higher than 2.75%, inductive reactive power is injected. Otherwise, the generator absorbs reactive power in the case of a positive voltage deviation, higher than 3.75%.

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 $tan\ \phi$. On the other hand, a case-by-case study is carried out in the French case 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 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 and downward 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 $tan\ \phi$ 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 not directly applied to them. That is, 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, [28] have proved that RES can provide reactive power control within a range limit considering acceptable levels of accuracy. Such provision reinforces the use of optimization and management methods 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 considering an OPF. 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 contracts upward and downward reactive power flexibility to be used during the operating stage. The upward and downward flexibility stands for the maximum reactive power that can go up or down from the expected reactive operating point of the DER, either at inductive or capacity operating point.

In the case of generating units under a standard reactive power policy, they are not available for participating in the service. Thus, the upward and downward flexibility are zero. 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 flexibility are considered. Despite these assumptions, generating units are remunerated (as long as scheduled) for the capacity of providing a change in their operating point of reactive power [29]. The first-stage is performed one day-ahead of the operating stage.

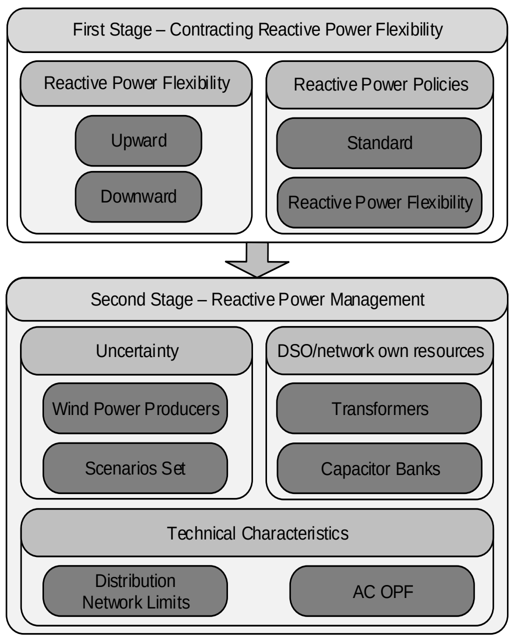

Fig. 2. Proactive reactive power management.

In the operating stage (second stage), the flexibility of reactive power contracted 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 defining the voltage set point of MV bus bar (secondary of HV/LV power transformer). As a standard policy, a fixed $tan\ \phi$ has been set for every DER with a +/- 5% flexible band (i.e., the DER can operate within this range). However, in the present methodology is assumed that the DSO determines the optimal point within that range, which promptly sends to the DER. In case of requiring a new operating point outside the boundaries, 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 single-period two-stage stochastic programming to cope with the uncertain behavior of RES and solve the reactive power management in a distribution grid. The problem aims to minimize the operating costs of the DSO by contracting reactive power flexibility in the first-stage to be used eventually during the operating stage. The DSO contracts reactive power from DER in 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 upstream connections of 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.

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 costs 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 recourse stage considering the realization of the scenarios. Hence,

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

where F^{HA} stands for the contracting of reactive power flexibility in the first-stage decision. The first-stage part of the objective function is modelled as

$$F^{DA} = \sum_{g=1}^{N_G} \left(C_{\mathrm{DER}(g)}^{Q,UP} R_{\mathrm{DER}(g)}^{Q,UP} + C_{\mathrm{DER}(g)}^{Q,DW} R_{\mathrm{DER}(g)}^{Q,DW} + X_{\mathrm{DER}(g)}^{new} C_{\mathrm{DER}(g)}^{new} \right) + \sum_{su=1}^{N_{SU}} \left(p_{TSO}^{Q,UP} RLX_{TSO}^{Q,UP} + p_{TSO}^{Q,DW} RLX_{TSO}^{Q,DW} \right), \tag{1.1}$$

where DER provide upward and downward reactive power flexibility under a specific cost. Furthermore, the DSO can change the policy for reactive power provision from DER. X^{new} 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 $\tan \phi$ 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 +/- 5% deviation that the requested Q value may vary at the upstream connection.

In parallel, F^{RT} stands for the recourse function of the objective function. The second-stage part of the objective function considers the costs for operating the distribution system in real-time, taking into account the realization of each of the scenarios under a predefined probability. Hence,

$$F^{RT} = \sum_{\omega=1}^{\Omega} \pi_{(\omega)} \begin{bmatrix} \sum_{g=1}^{N_G} \left(C_{\mathrm{DER}(g)}^{act} \left(r_{\mathrm{DER}(g,\omega)}^{Q,UP} - r_{\mathrm{DER}(g,\omega)}^{Q,DW} \right) + C_{\mathrm{DER}(g)}^{cut} P_{\mathrm{DER}(g,\omega)}^{cut} \right) + \\ p_{TSO}^{rlx,act} \left(rlx_{\mathrm{TSO}(\omega)}^{Q,UP} - rlx_{\mathrm{TSO}(\omega)}^{Q,DW} \right) + p_{TSO}^{Extra} rlx_{\mathrm{TSO}(\omega)}^{Extra} + \sum_{l=1}^{N_L} \left(C_{(l)}^{Cut} P_{(l,\omega)}^{Cut} \right) + \\ \sum_{cb=1}^{N_{CB}} \sum_{lv=1}^{N_{levels}} C_{CB(cb)} Z_{CB(cb,\omega,lv)} + \sum_{trf=1}^{N_{TRF}} \sum_{lv=1}^{N_{levels}} C_{TRF(trf)} Z_{TRF(trf,\omega,lv)} \end{bmatrix} \tag{1.2}$$

where generators change their operating point of reactive power at an activation price. Generation curtailment power is available at a greater cost for relaxing situations, in which the active power produced by the generators is creating problems 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 these contingencies 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 ability of transformers (not applied in the French case) and capacitor banks is also considered. The change in the tap is associated with a cost that considers the degradation in lifetime of the equipment when changing the set point [30]. In cases of higher need of 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.

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 presented by (2.1) and (2.2), respectively.

$$R_{\mathrm{DER}(g)}^{Q,UP,Min} \le R_{DER(g)}^{Q,UP} \le R_{DER(g)}^{Q,UP,Max}, \ \forall g \in \{1,\ldots,N_G\} \tag{2.1}$$

$$R_{\mathrm{DER}(g)}^{Q,DW,Min} \le R_{\mathrm{DER}(g)}^{Q,DW} \le R_{\mathrm{DER}(g)}^{Q,DW,Max}, \ \forall g \in \{1,\ldots,N_G\} \tag{2.2}$$

Similar constraints are also applied to the mathematical relaxation of the reactive power at the upstream connection.

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

$$P_{\mathrm{DER(g,\omega)}}^{cut} \le P_{DER(\mathrm{g})}^{op} + \Delta P_{\mathrm{DER(g,\omega)}}, \quad \forall g \in \{1,\ldots,N_G\}, \forall \omega \in \{1,\ldots,\Omega\} \tag{3.1}$$

where ΔP is the difference of active power between the realization scenario and the expected forecast in each scenario. It is worth mentioning that ΔP 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 connection 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.

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

In addition, the second-stage also includes the bounds of the second-stage variables and the non-anticipativity constraints. The non-anticipativity constraints relates 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

$$r^{Q,UP}_{\mathrm{DER}(g,\omega)} \le R^{Q,UP}_{DER(\mathrm{g})}, \ \forall g \in \{1,\dots,N_G\}, \forall \omega \in \{1,\dots,\Omega\} \tag{3.3}$$

$$r^{Q,DW}_{\mathrm{DER}(g,\omega)} \le R^{Q,DW}_{DER(g)}, \ \forall g \in \{1,\dots,N_G\}, \forall \omega \in \{1,\dots,\Omega\} \tag{3.4}$$

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* ϕ 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, equations (3.5) and (3.6) model the reactive power control from the DER. Hence,

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

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

where (3.5) models the reactive power control for the use of the standard reactive power control policy, while the modelling of the new reactive power policy is established through (3.6). X^{new} is a binary variable setting if the resource g uses the standard ($X^{new}=0$) or the new ($X^{new}=1$) policy for reactive power control. This decision variable assists the DSO to activate the new policy for a certain generator g in a specific period as required.

In contrast, reactive power provision from external suppliers represents the TSO request, i.e., a fixed Q value. Equations (3.7) and (3.8) give the upward and downward activation of the mathematical relaxation for external suppliers. However, this mathematical flexibility has a high penalty, since the goal is to meet the TSO request.

$$rlx^{Q,UP}_{\mathrm{TSO}(\omega)} \le RLX^{Q,UP}_{\mathrm{TSO}}, \qquad \forall \omega \in \{1,\dots,\Omega\} \tag{3.7}$$

$$rlx^{Q,DW}_{\mathrm{TSO}(\omega)} \le RLX^{Q,DW}_{TSO}, \qquad \forall \omega \in \{1,\dots,\Omega\} \tag{3.8}$$

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.

$$S_{DER(g,\omega)}^{Max}{}^{2} \geq \left(P_{DER(g)}^{op} + \Delta P_{DER(g,\omega)} - P_{DER(g,\omega)}^{cut}\right)^{2} + \left(Q_{DER(g)}^{op} + r_{DER(g,\omega)}^{Q,UP} - r_{DER(g,\omega)}^{Q,DW}\right)^{2}, \qquad \forall g \in \{1,...,N_G\}, \forall \omega \in \{1,...,\Omega\} \tag{3.9}$$

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

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

Thus, the reactive power consumption depends on the actual active power consumption under a *tan* ϕ, given by

$$Q_{L(l,\omega)} = \left(P_{L(l)} - P_{L(l,\omega)}^{DR}\right)\tan\phi, \ \ \forall l \in \{1,...,N_L\}, \forall \omega \in \{1,...,\Omega\} \tag{3.11}$$

where the *tan* ϕ can be settled at 0.4 like in [31]. In addition to the 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 modelled by levels of reactive power production, given by

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

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

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 an absolute function considering the difference between the tap selection in the present period with the previous one. Therefore, Z_{CB} is constrained by

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

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

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

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

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

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

where ΔV_{TRF} represents the voltage level to be activated in the transformer by the DSO. V_{TRF}^{levels} 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_{sb}^{ref} 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

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

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

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

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

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

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

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 has a thermal limit that should not be exceeded. Thus, the power flow through the distribution lines from bus *i* to bus *j*, and vice-versa is constrained by

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

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

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

$$V^{i}_{Min} \le V_{i(\omega)} \le V^{i}_{Max} \;, \forall \omega \in \{1,...,\Omega\} \tag{3.23}$$

4. Assessment of Reactive Power Management

This section presents a case study illustrating the application and performance of the developed model. The simulation has been carried out with MATLAB and GAMS.

4.1. Outline

The case study is based on a 37-bus distribution network (originally presented in [32]) adapted to support five DER, namely 3 CHPs and 2 wind turbines. **Error! Reference source not found.** depicts the distribution network, 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) [32]. The consumption characteristics and profile are imported from [33], and therefore summarized in Table II.

Table II: 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

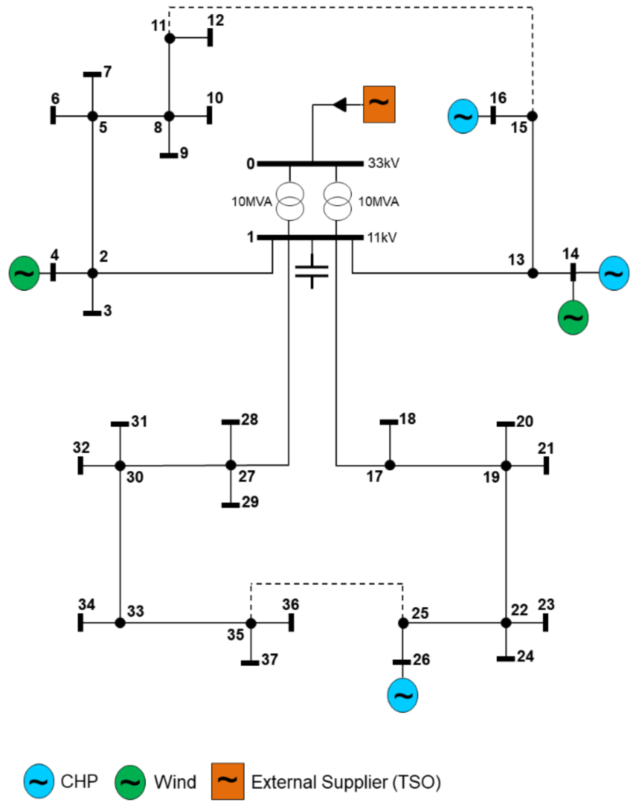

Fig. 3. 37-Bus distribution network (adapted from [29]).

Two transformers and capacitor banks are considered in the network with the characteristics presented in Table III. 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 [30], respectively. It is assumed that both equipment are owned and managed by the DSO.

Table III: 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

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

Table IV: 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	-	-	-	-

In addition, the cost for upward and downward reactive power flexibility is given in Table V. 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* ϕ) of each DER to a new policy considering a different *tan* ϕ. The new *tan* ϕ level is enforced by the DSO, according to the DER technical limits.

Table V: reactive power costs.

DER	Upward cost C^{up} (m.u./kVAr)			Downward cost C^{dw} (m.u./kVAr)			New policy cost C^{new} (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 VI gives the activation cost of the reactive power flexibility for each type of aggregator. It also includes the curtailment costs for each type of DER, as well as the cost related to the use of demand response.

Table VI: DER Activation and curtailment costs.

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

RES are modeled through stochastic variables. Thus, upward and downward reactive power flexibility is constrained by the upper and downward flexibility they offer to the DSO, and therefore by their technical limits. The uncertainty of wind power forecast is modelled in the form of scenarios over 24-hour periods, which can be found in [34,35]. A set of 10 scenarios were extracted for each wind generator. These scenarios are representative of the wind power distribution, and therefore, sufficient to test the simulator. In this case study, the standard reactive power policy of the DER are subjected to the Portuguese regulation, following Table I.

At the upstream connection, 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 VII. 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 VII: TSO request throughout 24h 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 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

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 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 to a certain DER in the specific period. Otherwise, the lightest color is show, meaning that the DSO maintains the standard reactive power policy with the DER.

Note that, both wind power plants are called to change most of the times their tan ϕ to the values under the new policy. The expected tan ϕ for all DER and period is depicted in Fig. 5. Through this figure, the DSO has an estimate of the tan ϕ that can be established in the new policy with the DER, accounting for +/- 5% of allowable deviation from the DER. 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.

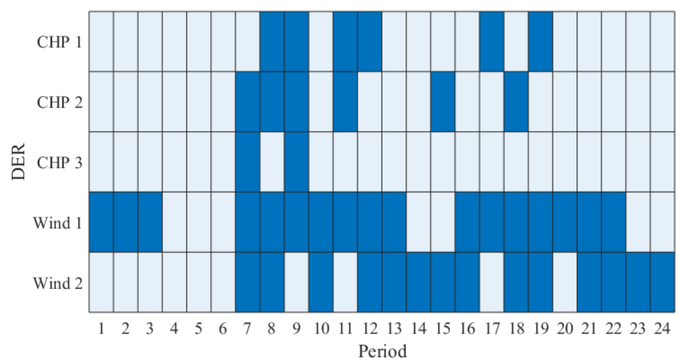

Fig. 4. Scheduling of new contract for reactive power provision by DER.

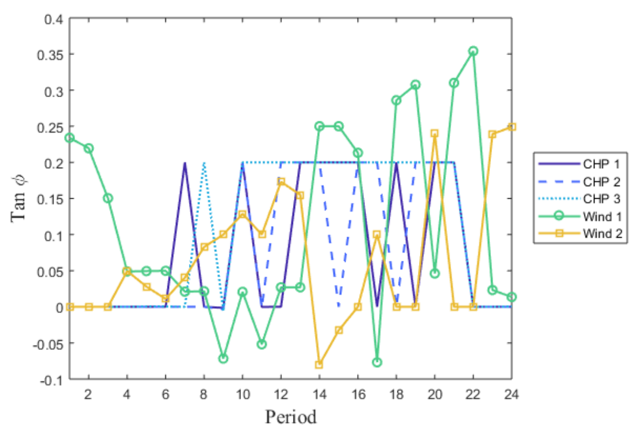

Fig. 5. Expected tan ϕ of each DER throughout the day.

Note 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 worth mention 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.

In addition, 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 $\tan \phi$ of each wind power producer in each scenario throughout the day is depicted in **Error! Reference source not found.** and Fig. 7, respectively. One can check through **Error! Reference source not found.** and Fig. 7 that reactive power provision slightly varies from scenario to scenario in most of the periods. In the first periods, wind power producer 1 (Fig. 6), provides higher reactive power to the system than wind power producer 2 (Fig. 7), since a new policy is assigned. In the remaining periods, both wind power producers present similar patterns of reactive power provision, since they are the cheapest DER to provide extra reactive power needs.

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 meted, cases in which the DSO cannot entirely provide the request may occur, 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 VIII. Note that, the cost varies with the use of the resources, and activation of the reactive power flexibilities. It is also important to mention that the used costs are indicative, and more studies should be performed to better definition of these values.

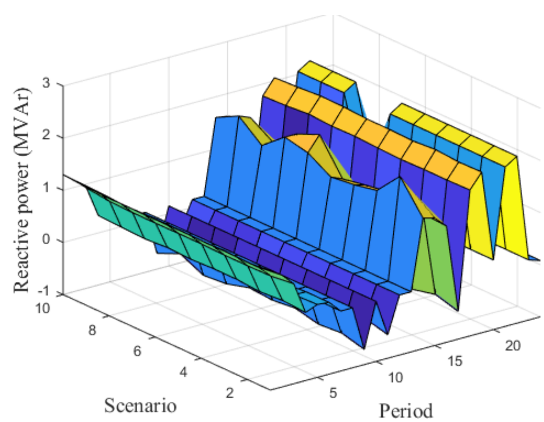

Fig. 6. Reactive power production by scenario and period for wind 1.

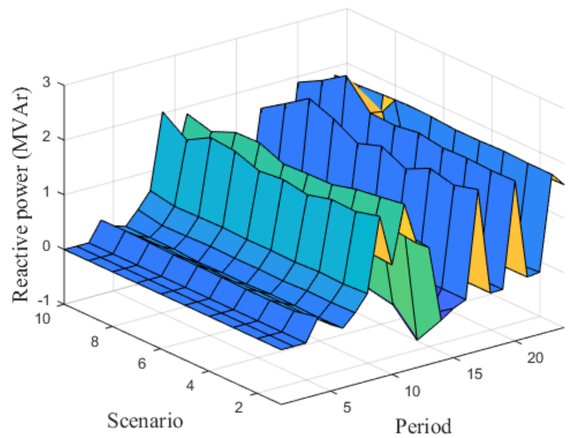

Fig. 7. Reactive power production by scenario and period for wind 2.

Table VIII: Service cost to the DSO throughout 24h 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

5. Conclusions

This work proposes a new tool for reactive power management by the DSO considering the 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 main result is the reply of the DSO to the TSO request with the amount of reactive power provided and the respective cost for the service.

Acknowledgement

This work is financed by the European Union's Horizon 2020 thorough the EU Framework Programme for Research and Innovation 2014-2020, within the EU-TDX-ASSIST project under the grant agreement No. [774500].

References

1. Pérez-Arriaga, I.J.; Ruester, S.; Schwenen, S.; Battle, C.; Glachant, J.-M. From distribution networks to smart distribution systems: rethinking the regulation of european electricity DSOs Available online: http://www.eui.eu/projects/think/documents/thinktopic/topic12digital.pdf.
2. Eurelectric Active distribution system management: a key tool for the smooth integration of distributed generation Available online: http://www.eurelectric.org/media/74356/asm_full_report_discussion_paper_final-2013-030-0117-01-e.pdf.
3. Christakou, K. A unified control strategy for active distribution networks via demand response and distributed energy storage systems. *Sustainable Energy, Grids and Networks* **2016**, *6*, 1–6.
4. Six, D.; Ramos, A.; Puente, E.R. Evaluation of current market architectures and regulatory frameworks and the role of DSOs Available online: http://www.evolvdso.eu/Home/Results.
5. Soares, T.; Bessa, R.J. Proactive management of distribution grids with chance-constrained linearized AC OPF. *International Journal of Electrical Power & Energy Systems* **2019**, *109*, 332–342.
6. Lampropoulos, I.; Alskaif, T.; Blom, J.; van Sark, W. A framework for the provision of flexibility services at the transmission and distribution levels through aggregator companies. *Sustainable Energy, Grids and Networks* **2019**, *17*.
7. Sarkar, M.N.I.; Meegahapola, L.G.; Datta, M. Reactive power management in renewable rich power grids: A review of grid-codes, renewable generators, support devices, control strategies and optimization algorithms. *IEEE Access* **2018**, *6*, 41458–41489.
8. Morais, H. *TDX-ASSIST: Agreed models, use case list, and use case description in UML, D1.2*; 2018;
9. Gayatri, M.T.L.; Parimi, A.M.; Pavan Kumar, A. V. A review of reactive power compensation techniques in microgrids. *Renewable and Sustainable Energy Reviews* **2018**, *81*, 1030–1036.
10. Parida, S.K.; Srivastava, S.C.; Singh, S.N. A review on reactive power management in electricity markets. *International Journal of Energy Sector Management* **2011**, *5*, 201–214.
11. Kekatos, V.; Wang, G.; Conejo, A.J.; Giannakis, G.B. Stochastic Reactive Power Management in Microgrids with Renewables. *IEEE Transactions on Power Systems* **2015**, *30*, 3386–3395.
12. Ding, T.; Yang, Q.; Yang, Y.; Li, C.; Bie, Z.; Blaabjerg, F. A data-driven stochastic reactive power optimization considering uncertainties in active distribution networks and decomposition method. *IEEE Transactions on Smart Grid* **2018**, *9*, 4994–5004.
13. Ding, T.; Liu, S.; Yuan, W.; Bie, Z.; Zeng, B. A two-stage robust reactive power optimization considering uncertain wind power integration in active distribution networks. *IEEE Transactions on Sustainable Energy* **2016**, *7*, 301–311.
14. Zubo, R.H.A.; Mokryani, G.; Rajamani, H.S.; Abd-Alhameed, R.; Hu, Y.F. Stochastic approach for active and reactive power management in distribution networks. In Proceedings of the 4th International Conference on Control, Decision and Information Technologies, CoDIT 2017; 2017; Vol. 1, pp. 456–461.
15. Al-Saadi, M.K.; Luk, P.C.K. Security-constrained two-stage stochastic unified active and reactive power management system of the microgrids. In *Advanced computational methods in energy, power, electric vehicles, and their integration. ICSEE 2017, LMS 2017*; Li, K., Xue, Y., Cui, S., Niu, Q., Yang, Z., Luk, P., Eds.; Springer, Singapore, 2017; Vol. 763 ISBN 978-981-10-6364-0.
16. Taghavi, R.; Seifi, A.R.; Samet, H. Stochastic reactive power dispatch in hybrid power system with intermittent wind power generation. *Energy* **2015**, *89*, 511–518.
17. Rabiee, A.; Soroudi, A.; Mohammadi-Ivatloo, B.; Parniani, M. Corrective voltage control scheme considering demand response and stochastic wind power. *IEEE Transactions on Power Systems* **2014**, *29*, 2965–2973.

18. Feinberg, E.; Hu, J.; Yuan, E. A stochastic search algorithm for voltage and reactive power control with switching costs and ZIP load model. *Electric Power Systems Research* **2016**, *133*, 328–337.
19. Lin, W.; Bitar, E. Decentralized stochastic control of distributed energy resources. *IEEE Transactions on Power Systems* **2018**, *33*, 888–900.
20. Mohseni-Bonab, S.M.; Rabiee, A. Optimal reactive power dispatch: a review, and a new stochastic voltage stability constrained multi-objective model at the presence of uncertain wind power generation. *IET Generation, Transmission & Distribution* **2017**, *11*, 815–829.
21. Fonseca, N.; Silva, J.; Silva, A.; Sumaili, J.; Seca, L.; Bessa, R.; Pereira, J.; Matos, M.; Matos, P.; Morais, A.C.; et al. EvolvDSO grid management tools to support TSO-DSO cooperation. In Proceedings of the CIRED workshop; IET: Helsinki, Finland, 2016; pp. 1–4.
22. Soares, T.; Bessa, R.J.; Pinson, P.; Morais, H. Active distribution grid management based on robust AC optimal power flow. *IEEE Transactions on Smart Grid* **2018**, *9*, 6229–6241.
23. ERSE Regulamento da rede de distribuição - portaria 596-2010 Available online: http://www.erse.pt/pt/electricidade/regulamentos/rededistribuicao/Documents/Portaria 596-2010 RRT RRD.pdf.
24. ERSE Despacho nº3/2010 Available online: http://www.erse.pt/pt/consultaspublicas/consultas/Documents/31_4/Despacho_3_2010.pdf.
25. ERSE Informação sobre faturação de energia reativa: princípios e boas práticas Available online: http://www.erse.pt/pt/electricidade/regulamentos/relacoescomerciais/Documents/Recomendações/Recomendação de energia reactiva.pdf.
26. Enedis Contrat d'accès au réseau public de distribution pour une installation de production raccordée en HTA - conditions générales Available online: https://www.enedis.fr/sites/default/files/Enedis-FOR-CF_13E.pdf.
27. Enedis Principe et conditions de mise en œuvre d ' une régulation locale de puissance réactive pour les installations de production raccordées au réseau public de distribution HTA Available online: https://www.enedis.fr/sites/default/files/Enedis-NOI-RES_60E.pdf.
28. Díaz González, F.; Martínez Rojas, M.; Sumper, A.; Gomis Bellmunt, O. Strategies for reactive power control in wind farms with STATCOM. In Proceedings of the EPE Wind Energy Chapter Symposium 2010; 2010; pp. 1–10.
29. Samimi, A.; Nikzad, M.; Kazemi, A. Coupled active and reactive market in smart distribution system considering renewable distributed energy resources and demand response programs. *International Transactions on Electrical Energy Systems* **2017**, *27*, 863–875.
30. Zhang, Y.J.; Ren, Z. Optimal reactive power dispatch considering costs of adjusting the control devices. *IEEE Transactions on Power Systems* **2005**, *20*, 1349–1356.
31. Beillan, V.; Bono, C.; Lesdain, S.B. De; Bricault, F.; Burtin, A.; Callec, J.; Caujolle, M.; Cayla, J.-M.; Costan, V.; Douzou, S.; et al. *Les systèmes électriques de demain: Un défi pour la transition énergétique*; EDF, Ed.; 1st ed.; Lavoisier, [in French]: Paris, 2018; ISBN 978-2-7430-2394-2.
32. Allan, R.N.; Billinton, R.; Sjarief, I.; Goel, L.; So, K.S. A reliability test system for educational purposes - basic distribution-system data and results. *IEEE Transactions on Power Systems* **1991**, *6*, 813–820.
33. Morais, H.; Sousa, T.; Soares, J.; Faria, P.; Vale, Z. Distributed energy resources management using plug-in hybrid electric vehicles as a fuel-shifting demand response resource. *Energy Conversion and Management* **2015**, *97*, 78–93.
34. Pinson, P. Wind energy: forecasting challenges for its operational management. *Statistical Science* **2013**, *28*, 564–585.
35. Bukhsh, W.A.; Zhang, C.; Pinson, P. Data for stochastic multiperiod opf problems Available online: https://sites.google.com/site/datasmopf/.