Sustainable Energy, Grids and Networks 27 (2021) 100507

Contents lists available at ScienceDirect

Sustainable Energy, Grids and Networks

journal homepage: www.elsevier.com/locate/segan

Remuneration mechanisms for investment in reactive power flexibility

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ARTICLE INFO

Article history:
Received 9 October 2020
Received in revised form 6 March 2021
Accepted 16 June 2021
Available online 24 June 2021

Keywords:
Voltage support
Reactive power
Market mechanism
Flexibility

ABSTRACT

The practices for the procurement of voltage control capability need changing because of the evolution of the power system driven by the penetration of renewable sources, low carbon policies, and decentralisation. New providers have to be involved. Therefore, new mechanisms to achieve cost-effective solutions have to be encouraged. To this aim, a cost-based incentive mechanism and a weighted auction are proposed for procuring additional reactive power capacity. Both mechanisms are conceived for encouraging effective investment in voltage control by reducing the overall procurement cost. Hence, the voltage sensitivity of the reactive power provider is part of both mechanisms. Voltage sensitivity is evaluated through the Multi Infeed Interaction Factors while the American Electric Power methodology is used for identifying the reactive power costs. The proposed mechanisms are general, and they can be exploited in transmission and distribution networks irrespective of the asset, which provides the reactive capacity. A case study concerning the 39-bus New-England power system is presented for providing the proof of concept of the proposed mechanisms. The analysis of the two mechanisms' pros and cons highlights that the weighted auction creates competition and shows low risks related to the exercise of potential market power.

1. Introduction

In the late 1980s, in Europe, the electricity market restructuring based on the liberalisation, unbundling, and liberalisation concepts pushed the fragmentation of the electricity sectors of the Member States [1]. As a consequence, the vertically integrated utilities have been dismantled and the activities have been left to independent companies; private investments have been allowed in the electricity sector; competition among electric companies has been encouraged. However, the grid ownership and the system operation have been considered to have natural monopoly characteristics [2]; therefore, regulated operators have been instituted for the transmission (TSO) and distribution (DSO) systems. The role of each regulated operator is to own and operate the power system to guarantee a reliable electricity supply and universal network access to third parties [3–5].

The focus of this paper is on voltage control service. Among the other activities, TSOs and DSOs, or indistinctly System Operators (SOs), are responsible for taking all necessary actions to maintain grid voltages within the acceptable ranges [4]. Power systems are designed to be operated within a narrow range of nominal voltages to guarantee the reliability, safety, and security of the supply [6]. If voltage limits are exceeded, components and loads can be damaged or destroyed. Moreover, strict security and safety issues and large-scale brownout may happen if voltage collapses [7,8]. Voltage control is a local activity [7,9–11]; traditionally, a great contribution to voltage control is provided by the traditional thermal power stations equipped with synchronous generators already connected for injecting active power on higher voltage networks. Although these resources are third-party owned in a liberalised electricity sector, the participation in voltage support is, to some extent, mandatory; however, additional voluntary service is provided in some cases [12,13]. As pointed out in Section 2, if the support is paid, the remuneration is typically based on fixed rates defined by bilateral agreements or regulated tariffs [12–14].

In recent years, the electricity sector is experiencing profound changes motivated by the energy transition which includes unprecedented measures for improving the environmental sustainability of our economies and lifestyles [15,16]. The common goal of the proposed policies is the decarbonisation of the economy. Especially in the European Union (EU), the electricity sector is considered pivotal in the transition towards a climate-neutral society [17,18]. The transformation of the electricity sector has to accommodate the necessary changes at a reasonable cost while taking advantages of the available opportunities without compromising the security and quality of the electric supply. The

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https://doi.org/10.1016/j.segan.2021.100507

Nomenclature

AEP	American Electric Power
ASD	Adjustable Speed Drivers
AVR	Automatic Voltage Regulator
CAPEX	Capital Expenditure
DER	Distributed Energy Resource
DFIG	Doubly-Fed Induction Generator
DSO	Distribution System Operator
FACTS	Flexible AC Transmission System
MIIF	Multi Infeed Interaction Factor
NERC	North American Electric Reliability Corporation
OLTC	On Load Tap Changer
OPEX	Operational Expenditure
PV	Photo Voltaic
PVR	Primary Voltage Regulation
SO	System Operator
STATCOM	Static synchronous compensator
SVC	Static Var Compensator
SVR	Secondary Voltage Regulation
TSO	Transmission System Operator
TVR	Tertiary Voltage Regulation

main drivers of the ongoing transformation of the power system and electricity markets are the availability of affordable renewable energy sources, the decentralisation of the electric energy production, the advent of new loads due to electrification policies, and the digitalisation which enables cost reductions, new functionalities, and contributes in improving system resiliency [19–21]. Planning and operational procedures require drastic changes, the energy transition requires the active participation of all actors connected to the power system to provide the flexibility that is necessary to accommodate the growing presence of distributed generation fed by renewables without requiring extensive traditional network reinforcement campaigns [17,19,20].

The decentralised, liberalised, and fragmented power system structure makes no longer suitable the voltage control practices historically in use. The current practices for voltage control are mined by the reduced availability of large power plants and by the presence of Distributed Energy Resources (DERs) since the emergence of bidirectional power flows in networks that modify the traditional power system voltage profile [21–23]. In this context, new practices and new service providers are needed to ensure the voltage support required, the decentralisation of operational and market processes encourages the exploitation of smaller generation facilities to solve local grid problems [24]. The active participation in voltage control of third-party resources, which can be connected to either the TSO or the DSO level, may relieve contingencies, increase the hosting capacity, and provide an effective way for improving the coordination between TSOs and DSOs [22,25,26]. New investments in voltage control resources have to be encouraged to expand the set of voltage support providers. In a liberalised electricity sector, new service provision capability investments have to be encouraged to foster competition among service providers.

As introduced by the concept of flexibility, the participation in voltage control of the available resources connected to the power system represents an alternative to the investment in additional network equipment (e.g., on load tap changer transformers, capacitors, voltage regulators) [20,27]. Even if the connection of third-party resources may be seen as a part of the problem since the introduced issues, these assets can contribute to the power system evolution if adequately managed. The participation of the connected resources in the network operation has been extensively investigated in literature [28–32]. The optimal siting and sizing of the resources have represented the primary research goal to contribute to reducing energy losses and voltage problems. However, in a liberalised electricity sector, SOs are not allowed to own and operate generation assets or decide the point of connection in the network. The SOs have to guarantee universal access to all third parties (generators, loads, storage facilities) at any point of the network [4,33]. Given the level of diffusion of potentially controllable assets (power converter interfaced generators, storage, dispatchable loads), the scientific community investigated how to effectively exploit their contribution [17,22,25,26,34–38]. In the context of a high level of diffusion of controllable resources connected to the power system, it is of interest to identify, for each grid problem, the most effective set of potential service providers. In a liberalised power system, it is necessary to stop relying on procurement mechanisms derived from the former power system structure. The energy transition requires the evolution of the mechanism for procuring grid services, in this context, it is fundamental to provide indirect economic stimulus to encourage third-party investments in the most effective technologies and nodes.

To this aim, this paper proposes two different local mechanisms for procuring reactive power capacity. The stimulus for investments is provided according to market-based principles, the remuneration for the third-party providers depends on the actual need for the grid service and the effectiveness of the contribution. Competition among the potential providers is encouraged. Since the ongoing transition towards a decentralised power system and electricity market and the local characteristic of voltage control, this paper proposes two decentralised mechanisms for procuring locally the voltage control support required to solve the local needs for grid services. A cost-based incentive mechanism and a weighted auction are described and compared for highlighting strengths and weaknesses. The network topology and impedances influence voltage control measures; therefore, both mechanisms involve calculating network voltage sensitivity. In the proposed cost-based incentive mechanism, the remuneration coefficients depend on the voltage sensitivity related to the provider's connection bus and the share of the overall capital cost associated with the reactive power provision. The voltage sensitivity is quantified by resorting to the Multi Infeed Interaction Factor (MIIF) [39]. The share of the overall CAPital EXpenditure (CAPEX) related only to the reactive power capacity is estimated through the allocation factor defined by the American Electric Power (AEP) methodology [14,40]. The proposed weighted auction is characterised by a first step in which the received bids are weighted according to a malus coefficient which depends on the voltage sensitivity analysis. Once the set of accepted bids is identified, the providers' remuneration is decided considering bids' original price. A case study is considered to assess each mechanism's exploitation and point out the aspects that strongly depend on the actual power system's characteristics. The assessment is aimed at providing recommendations on the most suitable mechanism to be adopted depending on the power system characteristics.

The main contribution of this paper is the proposal of effective local mechanisms for fostering the participation of new voltage control providers and the related proof of concept for the application of those mechanisms to realistic power system scenarios. Both mechanisms rely only on economic efficiency principles and devise the remuneration based on the volume of the need and the actual effectiveness of the resources contracted. Concerning

Table 1
Structure of several remuneration mechanisms in force [12,14].

Procurement and remuneration mechanism	Country
Bilateral agreements for reactive power capacity	France (only in several areas), Germany, Netherland
Bilateral agreements for reactive energy	France, Switzerland, Germany, Nordel (only for the additional service)
Tenders for reactive power capacity	Spain (additional service, partially in force)
Tenders for reactive energy provision	Belgium, Spain (for additional service, partially in force)
No remuneration	Italy, Nordel, Spain (for mandatory service)
Regulated price for reactive energy	NERC
Opportunity cost for additional service	Spain, Germany, NERC

the current mechanisms (described in Section 2), the proposed mechanisms formalise a remuneration to the service providers which tends for each technology to the actual marginal cost of the service provision seeking to improve economic efficiency. Since the third-party contribution in voltage control may represent an alternative to the investments in traditional network equipment; in the proposed mechanism, the third-party investments in voltage control capability compete in a level playing field with traditional assets.

The paper is organised as follows. In Section 2 the voltage support procurement mechanisms in force in several countries are revised; moreover, the state of the art of voltage control schemes is analysed from a technical and economic point of view. The definition of the network voltage sensitivity indicators is also provided in 2. In Section 3, the proposed cost-based incentive mechanism and the weighted auction are described. The case study is presented and the outcome of the proof of concept discussed in Section 4. Finally, the final remarks are provided in Section 5.

2. State of the art on voltage support services and related market mechanisms

Voltage control requires procuring enough reactive power capability from different resources classified as network and third-party-owned. Generally, the SO owns the network equipment; the resources related to investment and operational costs are returned to the SO as revenues collected by charges applied to the served customers [41]. Along with network equipment, the generators connected to the transmission system provide the main share of the reactive power support [12]. Typically, this voltage control capability is procured according to a monopsonist mechanism in which a single buyer (the SO) interacts with multiple service providers (generators which act as third party control resources) [12–14]. In this structure, the third-party resources implicitly compete with the resources owned by the SO.

In general, a minimum mandatory level of reactive power support is imposed as a connection condition [12–14,42,43]. Some existing regulatory frameworks define a cost-based remuneration for the provision of the mandatory reactive power support [12–14,42,43]. The remuneration for transmission generators is based on the recognised procedures defined in network codes or by long-term bilateral contracts; capacity and hybrid remuneration mechanisms are also implemented. Some frameworks also recognise the lost opportunity related to the active power output [12–14,42,43]. Table 1 resumes the characteristics of the remuneration mechanism in the reviewed countries.

As confirmed by the extensive literature review, several remuneration mechanisms are implemented for procuring reactive power support. There is no uniformity on the recognised product (reactive power capacity and or reactive energy) neither in the procurement method (long-term, short-term, or mandatory provision) nor the pricing mechanism (bilateral negotiation, tendering, regulated prices, absence of remuneration).

Even if the proposals for an efficient remuneration of the provision of voltage support [14,41,42,44–51], most of the practices currently in use do not fully comply with this aspect (Table 1).

In general, there are some principles that a procurement mechanism should meet: transparency, technological neutrality, and economic efficiency. The mechanism should promote a level playing field that encourages competition among service providers [52,53]. The reviewed procurement and remuneration mechanisms in force do not seem explicitly designed to achieve those principles. While procurement mechanisms based on bilateral agreements lack transparency, no remunerated mandatory provisions miss in achieving cost-efficiency and encouraging competition. Moreover, the Volt/VAR service's local characteristic allows the providers to gain from locational advantages and market power if they freely bid quantities and prices.

Furthermore, since the SO owns voltage support assets, the participation of those assets should be transparent in the procurement method. Moreover, the use of active power generation curtailment and load shedding as additional control measures should also be specified in the procurement method. Therefore, the procurement mechanism should be formulated to include all the control measures that respectively counteract over-voltages and under-voltages; the cost of using these measures depends on the technology of the involved assets and the control actions needed. The lost opportunity has to be accounted for in case of the reduction of the active power output.

2.1. Voltage control

In general, in high voltage networks, the voltage control mechanism consists of a hierarchical control scheme formed by several layers [10–13,34]. The three-layer hierarchical structure has been first introduced in France and Italy [10,34,54], while a simplified, centralised voltage control scheme is exploited in other countries [12]. The centralised control is implemented in Germany, Switzerland, some United States regions, and NORDEL in Scandinavia [34,55]. Belgium and Spain also adopted a centralised control; however, the adoption of a hierarchical scheme is under analysis [34,55]. The hierarchical voltage control has been studied in the Brazilian power system [56].

The three-layer hierarchical voltage control allows to minimise power losses, increase stability margins and available ampacities for active power transfers [55,57]. Each hierarchical control layer is a closed-loop dynamically decoupled from the other layers [34,55]. The Primary Voltage Regulation (PVR) adjusts in real-time the voltage on the generator's terminals following a local setpoint [11,34,55]. The Secondary Voltage Regulation (SVR) is based on the subdivision of the power system in independent control areas within which a centralised scheme for voltage control is exploited [11,34,55]. The Tertiary Voltage Regulation (TVR) operates on the national level and coordinates the control areas [11,34]. Table 2 resumes the main features of the voltage control schemes already implemented [11,13,55].

In both centralised and hierarchical voltage control schemes, a real-time (or dynamic) and flexibility (or steady-state) support can be differentiated [11,34,55,58]. The real-time support is provided by the PVR and requires resources capable to continuously adapt their voltage outputs [11,34,55]. The flexibility support encompasses the SVR and the TVR. The resources are dispatched periodically by the TSO for achieving the desired voltage profiles and restoring the reactive power reserves [11,34,55]. Since the

Table 2
Characteristics of traditional hierarchical voltage control [11,13,55].

	PVR	SVR	TVR
Time constant	τ is in the order of 1 or two cycles	τ is in the order of seconds	τ is greater than a tenth of seconds
Setpoint	Voltage	Voltage or reactive power	Voltage or reactive power
Control resources	Synchronous generators and condensers, SVC	Synchronous generators and condensers, SVC, FACTs devices, capacitor banks, reactors	Synchronous generators and condensers, SVC, FACTs devices, capacitor banks, reactors

differences between real-time and flexibility supports, not all voltage control resources can provide both types of supports.

Voltage control resources can be categorised into dynamic and static devices according to their capability to perform control actions. The dynamic devices can adapt the voltage output within one cycle, while the static devices cannot respond fast enough after a disturbance [55]. Dynamic devices can be further classified into three categories [41]: pure reactive power compensators (e.g. synchronous condenser, FACTS devices), inverter-based DERs and generators (e.g. PV systems, wind turbines, fuel cells, microturbines, diesel generators, storage devices), and Adjustable Speed Drives (ASDs). These devices can provide voltage support by emulating synchronous generator dynamics thanks to the flexibility of interface inverters [25,35,36]. Static devices are capacitors banks, reactors, and tap changers of transformers.

2.2. Network voltage sensitivities

In electric networks, the voltage influence of a bus over the others depends on network topology, network impedances, and the system's operating point. The network sensitivity analysis allows to characterise the coupling among busses and to identify the area of influence of each generator [42]. Since the voltage control actions' effectiveness depends on the network characteristics, the voltage mutual sensitivity of the busses plays a crucial role in identifying the most effective control source within an available set.

The coupling among busses can be quantified through sensitivity indicators such as Multi Infeed Interaction Factors (MIIFs) [39] and the electrical distances [42]. In this paper, the MIIF is used to quantify each generator's influence on the network's load busses.

The MIIF has been proposed for computing the interaction in terms of produced changes between the AC voltages of two inverters connected at different nodes [39]. The MIIF is defined as in (1).

$$MIIF_{ij} = \frac{\Delta V_i}{\Delta V_j\big|_{1\%}} \tag{1}$$

where $\Delta V_j\big|_{1\%}$ is the voltage variation imposed at the jth bus such that a voltage step of 1% is produced on this bus. ΔV_i is the voltage variation observed on the ith bus caused by the voltage step imposed in the jth bus. Conventionally, the voltage step $\Delta V_j\big|_{1\%}$ is considered caused by the virtual switched connection of a shunt reactance on the jth bus [39]. The network MIIF matrix is obtained by calculating the MIIF values for all nodes; in general, the MIIF matrix is not symmetrical. The coefficient $\mathrm{MIIF_{ij}}$ quantifies the influence of the voltage on bus ith on the bus jth. The $\mathrm{MIIF_{ji}}$ has a dual meaning. Considering a fixed operating point for the system, the value of $\mathrm{MIIF_{ji}}$ depends on the impedance that interconnects the nodes and the shunt impedance of each bus [39].

The MIIF assumes values between 0 (no interaction between the two busses) and 1 (the two busses coincide) [39]. As a general rule, if $\mathrm{MIIF_{ij}}$ is less than 0.15 the interaction between the ith and the jth busses can be neglected, if the $\mathrm{MIIF_{ij}}$ lies between 0.15 and 0.40, the bus coupling is considered moderate. Simultaneously, if $\mathrm{MIIF_{ij}}$ is greater than 0.40, the ith and jth busses are considered strongly coupled [39,59].

2.3. Voltage support economics

From the providers' perspective, voltage control costs can be classified in terms of investment and operational expenditures [50]. The investment costs are the CAPEX related to the equipment required for reactive power provision. The invariable OPEX depends on the minimum reactive power for the source normal operation (internal losses) and the share of the total equipment maintenance cost allocated to the reactive power provision. The variable operational costs are related to internal energy losses in the equipment involved in providing additional reactive power support and, if active power reduction occurs, the lost opportunity [60].

Reactive power can be provided by both dedicated devices and devices mainly devoted to active power production; therefore, two categories can be identified: pure reactive power providers and mixed active–reactive power providers. The CAPEX for pure reactive providers is equal to the device's investment cost and the related auxiliary equipment. Conversely, for the second category of devices, the CAPEX is a share of the total CAPEX plus the investment for the auxiliary equipment needed for reactive power production. Technology innovation and regional and global factors impact the actual prices of these devices. In this paper, only a qualitative overview of involved CAPEX is provided. Furthermore, not all technologies are currently available for all voltage levels, and besides, considering the already available technologies, the costs may differ across voltage levels. Capacitor banks, shunt reactors, FACTS devices, and synchronous compensators are pure reactive power producers. In general, the CAPEX of capacitor banks and shunt reactors is low, while the cost of the synchronous condensers is high [14,61]. Retrofitting synchronous machines for obtaining synchronous condensers and FACT devices have a comparable cost which lies between the previously mentioned assets [14,61]. Among active and reactive power providers are synchronous generators, asynchronous generators (e.g., DFIG), and inverters as the interface of PV plants, energy storage, wind turbines, and motors.

For synchronous generators, the exciter essentially identifies the equipment required for reactive power provision, needed for the active power production. Separating the active and reactive power investment cost is challenging [61]; however, approaches based on the value of the operating power factor (PF) allow to define the allocation factor for splitting the annual revenue requirement of active and reactive power production [14,40]. The allocation factor proposed by the American Electric Power (AEP) is calculated as the squared ratio of the reactive power capability and the total capability at PF of 1 [$\mathrm{Mvar^2/MVA^2}$] [14,40].

The decoupling of CAPEX applies to inverters. In some cases, reactive power provision may require oversizing the inverter for the full provision of the capacity for active power production [36] and the oversizing cost can be accounted as a reactive power production CAPEX [14]. This cost depends on the minimum voltage support required as a network connection requirement. That influences the oversizing rate, evaluable as 1/PF [37]. It is estimated that the inverter cost is about 10%–20% of the total cost of a PV plant; therefore, an inverter oversized of 10% would imply a 2% increase of the overall PV plant CAPEX [14]. For a fuel cell power plant, it has been estimated that oversizing the inverter for operating at PF 0.8 would increase the overall plant cost by about 2 or 3% [44].

The arguments on oversizing the power inverters can be generalised to DFIG generators. The investment cost related to the reactive power equipment for wind generators is estimated to be about 3%–4% of the total CAPEX of the power plant [14]. The CAPEX of reactive power support of ASD is related to the control equipment. Since the extremely short payback time of ASD devices due to energy savings, the CAPEX related to the reactive power support may be neglected [41]. Besides, if a centralised control is implemented, the share of the communication infrastructure cost must be considered in each provider's reactive power production CAPEX.

The operational expenditures (OPEX) related to internal active power losses caused by the reactive power production are calculated depending on the generator's operational point through the loss curve. Synchronous generators, inverter-based DERs, DFIGs, and STATCOMs show a loss curve which can be approximated by a second-order polynomial function [35,36,38,45,60]. Moreover, the loss curves are symmetrical, considering positive and negative reactive power outputs [36].

The operational cost of reactive power provision by network equipment, such as capacitor banks and shunt reactors, is related to the active power losses due to the parasitic elements, the losses on the discharging resistance, and the accelerated depreciation of the capital cost associated with switching operations. Therefore, the cost of the active power losses, the unitary cost for each switching operation can be calculated as [€/switching operation]) [45]. Similarly, the unitary cost of a step operation can be estimated for OLTC transformers [45].

Since this paper aims to propose procurement mechanisms for new investment in reactive power capabilities, the costs considered in the following sections refer only to CAPEX. OPEX is neglected because they are much smaller (e.g. overall investments for building a new plant, refurbish an existing one, installing new equipment). Then, a dedicated mechanism would be required.

3. Proposed mechanisms for encouraging new investment in voltage control capability

The differences between active and reactive power make active power market mechanisms not directly applicable to procure reactive power. Reactive power has to be locally provided since it cannot travel over long distances [9]. That condition limits the potential size of the reactive power market, and then, the competition. Furthermore, the characteristics of reactive power demand and the imposed network voltage limits lead to high price volatility of reactive power spot pricing [62–64]. Moreover, reactive power asymmetry requires adopting dedicated mechanisms for procuring capacity for reactive power injection and adsorption. Injecting or adsorbing the same quantity of reactive power may impose different costs that depend on the provider's technology. To illustrate, a power plant can contribute to reactive power provision by oversizing the generators, transformers, and converters or by installing behind the point of common coupling capacitors banks, shunt reactors or static compensators.

Based on power system analysis addressed by the SO for defining grid development plans, new investment in reactive power support can be required to comply with the expected reactive power needs. Under this planning context, a long-term cost-based incentive mechanism and a long-term weighted auction are proposed to encourage the participation in voltage control of new power plants, or in general, new assets owned by third parties. In Table 3, the main features of the two proposed market mechanisms are outlined. In both mechanisms, the remunerated product is the reactive power capacity which availability has to be guaranteed for a period that coincides with the horizon of the grid development plan defined by the SO.

Table 3
Overview of the main features of the proposed market mechanisms.

	Cost-based incentive mechanism	Weighted auction
Product	Reactive power capacity	Reactive power capacity
Product availability	The horizon of the grid development plan	The horizon of the grid development plan
Remuneration	Cost-based, related to regulated reference costs	Auction price
Participation period	Always open	Requires opening a call for investment
Overall quantity acquired	Based on a budget or a reactive power capacity cap	Based on a reactive power capacity cap
Public availability of network coefficient	Required	Optional

As highlighted in Section 2, because no reactive power markets are implemented, there is a lack of historical economic information. The SO can also influence the required voltage control needs and the related market output depending on the use of tap changers, line reconfigurations, and investing in owned resources. These two aspects lead to significant uncertainty for potential participants of a reactive power procurement mechanism. The high level of uncertainty makes the investment for reactive power provision very risky. Procurement mechanisms looking ahead in the future in the long term are aimed to hedge the commented uncertainty and associated risk. The long-term procurement carried out before service delivery enhances the competition since it allows new service providers to invest in delivering the service when required.

For the sake of simplicity, only the reactive power capacity related to injection is considered in the case study described in this paper. Still, the same procedure works for reactive consumption also.

3.1. Cost-based incentive mechanism

The proposed cost-based incentive mechanism acknowledges a remuneration to newly connected assets (e.g. new power plants or retrofitting of existing plants) based on the reactive power capacity made available to the SO for being used in voltage control.

The proposed incentive mechanism encourages the investment in reactive power capacity on the network nodes that have a greater influence on the neighbourhood busses voltage. A cap on the overall amount of incentives delivered to the power system actors can be defined according to the reactive power capacity required by the SO for facing the expected operating scenarios.

The investments are reimbursed according to a cost-based mechanism that considers CAPEX's share related only to the reactive power provision and the effectiveness of the control service provided. The remuneration formula proposed in this paper is defined in (2).

$$R = K_g K_q C_T \tag{2}$$

where R is the remuneration to the control service provider [€], K_g is a coefficient related to the effectiveness of the voltage control resource, K_q is a coefficient that allows separating the quota of investment related to reactive power provision from overall CAPEX, and C_T is the CAPEX of the investment in the new power plant or installation [€].

In Fig. 1, the calculation of the cost-based remuneration mechanism for the additional reactive power capacity is illustrated.

In the case study presented in this paper, K_g is based on the MIIF values while the coefficient K_q is defined according to the

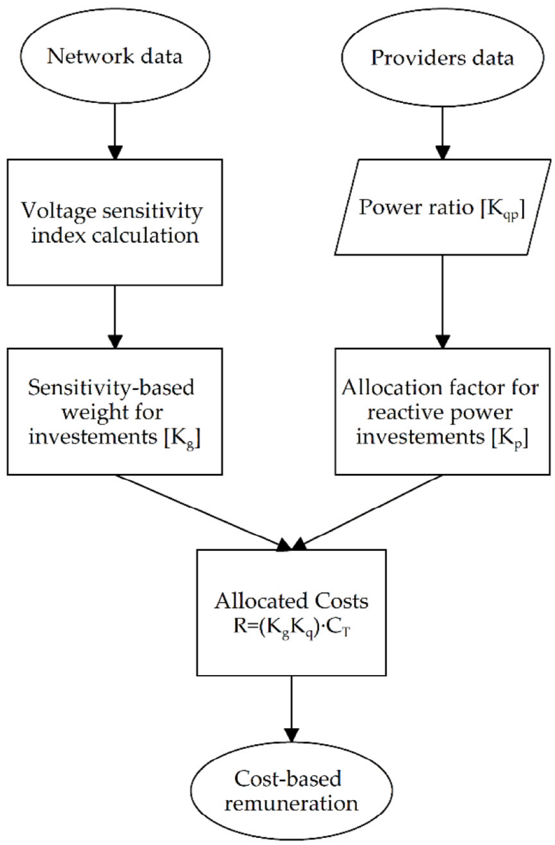

Fig. 1. Flowchart of the cost-based incentive mechanism.

AEP methodology [14,40]. The K_g value depends on the topology, the network parameters, and the operating point of the power system, and it has a different value for each node of the system. The procedure for calculating the K_g is described as follows.

At first, the network MIIF coefficients are calculated; for a network formed by m nodes, an mxm MIIF matrix is obtained. Considering the ith bus, $\Gamma^{(i)}$ is the set of busses with a MIIF value greater than 0.15, the dimension of $\Gamma^{(i)}$ is $n_i \leq m$. The average value of MIIF for the ith node is then defined considering the set $\Gamma^{(i)}$ according to (3).

$$\overline{MIIF}_i = \frac{\sum_{j=1}^{n_i} MIIF_{ij}}{n_i} \tag{3}$$

The dimension of each node area of influence is considered with the coefficient K_z which is related to the dimension n_i of the set $\Gamma^{(i)}$. The value of K_z is defined in (4).

$$K_{z-i} = \frac{n_i}{max_{j=1,\ldots,m}\left\{n_j\right\}} \tag{4}$$

The parameter K_{MIIF} considers both the average influence in terms of the voltage of node ith and the dimension of its area of influence, it is calculated according to (5).

$$K_{MIIF-i} = K_{z-i} \cdot \overline{MIIF}_i \tag{5}$$

The weight K_g for the investment in the node ith is defined for the whole network and is calculated according to (6).

$$K_{g-i} = \frac{K_{MIIF-i}}{max_{j=1,\ldots,m}\left\{K_{MIIF-j}\right\}} \tag{6}$$

The allocation factor K_q depends on the apparent power (S_n) and the reactive power capacity (Q_c) offered as a voltage control resource, it is calculated according to (7) [14,40].

$$K_q = \left(\frac{Q_c}{S_n}\right)^2 \tag{7}$$

Considering the reactive power capacity Q_c, for the power plant maximum active power capacity (P_c), it is possible to define the power ratio coefficient K_{qp} as in (8).

$$K_{qp} = \frac{Q_c}{P_c} \tag{8}$$

Since the apparent power of the power plant is calculated as $S_n = \sqrt{{P_c}^2 + (K_{qp}P_c)^2}$; then the allocation factor for the investment in reactive power is calculated as (9).

$$K_q = \frac{{K_{qp}}^2}{1 + {K_{qp}}^2} \tag{9}$$

If the mandatory service is remunerated, these investments in reactive power are remunerated considering the K_q coefficient. If voluntary service is also provided, the remuneration of the overall investments in reactive power support is remunerated according to the value of the K_q defined in (9) according to the actual value of the ratio K_{qp}. Otherwise, if only the voluntary service is allowed to be reimbursed, the K_{qp} is calculated only considering the quota of reactive power capacity offered besides the mandatory service, as defined in (10).

$$K_{qp}{}' = \frac{Q_c - Q_m}{P_c} \tag{10}$$

where Q_c is the overall reactive power capacity of the power plant, while Q_m is the reactive power capacity to be provided as a mandatory service.

3.2. Weighted auction

In this section, a long-term weighted auction is proposed for allowing the SO to procure the required reactive power capacity from third-party investors.

In the weighted auction, the traded product is defined in terms of reactive power capacity, participants in the weighted auction offer price–quantity bids (e.g. €/Mvar bids).

The auction proposed in this paper consists of the two steps described by the flowchart of the weighted auction depicted in Fig. 2. In the first step, the received price–quantity bids are weighted according to the malus coefficient that models the related asset's voltage control effectiveness. Once the bids are ranked, the accepted weighted bids are determined by the total reactive power quantity that must be procured according to the SO. Once the set of accepted bids is identified, in the second step, this set is reordered according to the original prices to obtain the actual price to be paid to all the accepted providers.

In this paper, a malus coefficient calculated from the MIIF values introduced in Section 3.1 is proposed. By considering the weight for the investment K_{g-i} connected at the node ith as in (6), the malus coefficient K_{M-i} for weighting the bids related to the ith bus is defined as in (11).

$$K_{M-i} = 2 - K_{G-i} \tag{11}$$

Then, considering a generic jth bid, the related weighted price Θ_j is calculated as in (12).

$$\Theta_j = K_{M-i}\Phi_M \tag{12}$$

where Θ_j is the weighted price of the jth bid related to a provider connected to the ith node, K_{M-i} is the malus coefficient associated with the ith node, and Φ_M is the original price of the jth bid related to a provider connected to the ith node.

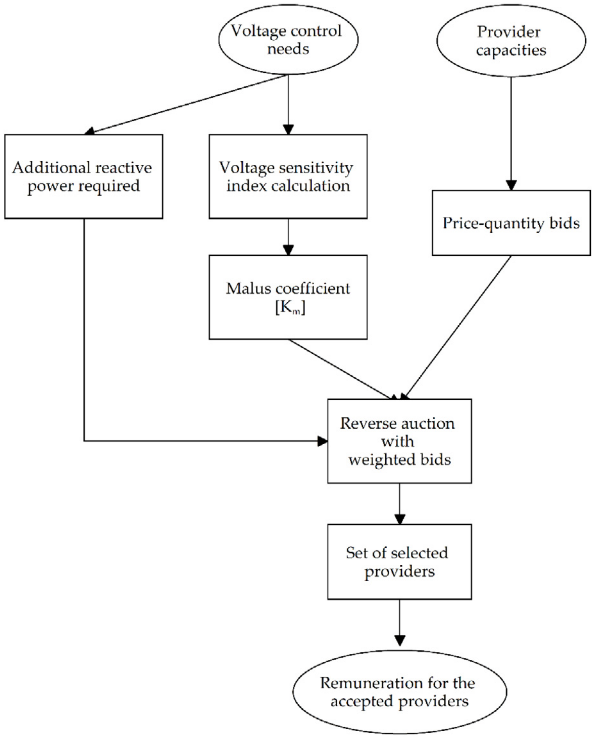

Fig. 2. Flowchart of the process of the two-steps auction.

The price asked in the offers should be related to the investment required for providing the voltage control service. The share of the overall investment, which is finally included in the bids, would depend on investors' risk attitude. To illustrate, a risk-averse investor would bid the full annualised investment cost in a single auction. In contrast, a less risk-averse investor would split it over several auctions, expecting that, after the current grid development plan ends, new calls would be able to recover the rest of the investment. This behaviour would allow the investor to bid a lower price in the current auction than the more risk-averse providers' offers.

Therefore, the quantity and the price offered by the participants in the auction comes from strategic reasoning. The power plant technology and the oversizing factor define the amount of reactive power capacity offered, and the relative allocated overall CAPEX should be considered. Suppose there is enough competition, the behaviour and the location of the other market participants are unknown. In that case, it represents another incentive in bidding the actual marginal cost since better-located providers will be selected when the price offered are equal.

Moreover, the SO can participate in the procurement mechanism by bidding on the used network asset investment cost. In a procedure audited by the regulatory body, the SO has to declare ex-ante the network assets included in the investment plan. The cost related to these assets or service has to be acknowledged by the regulator. For the sake of transparency, these costs have to be known ex-ante by the participants in the weighted auction. Then in the weighted auction, the SO assets compete at the same level as the ones owned by the third-party providers (i.e. the investment are discounted according to the corresponding malus coefficient and then are sorted in the list of all weighted price–quantity bids). According to this framework, traditional network reinforcement solutions compete with third-parties' flexibility. It allows identifying the cheapest set of initiatives for developing the power system irrespective of the proposer.

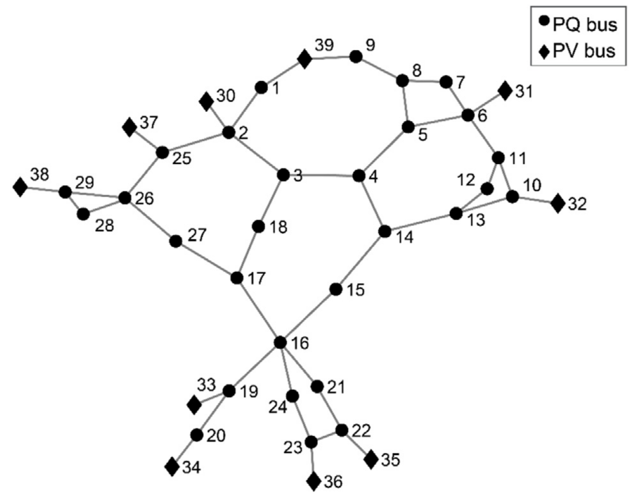

Fig. 3. IEEE 39 bus system, New-England power system.

4. Case study and discussion

The case study presented in this paper is based on the IEEE 10-generator, 39-bus New-England power system, as defined in [65–68]. The power system under analysis is a high voltage 345 kV network. In Fig. 3 the New-England power system topology is depicted, while the data about busses, generators, and branches are provided in Appendix A. The power system analysis and the power flow calculations have been done with MATPOWER [69].

The case study consists of setting up a call for reactive power capacity investments in the 39-bus New-England power system where different strategies can be adopted. The call for additional reactive power capacity can involve all network busses considering or not the voltage control effectiveness. Alternatively, the call for investments can be focused only on a set of busses.

In the case study described in this paper, the call for investments is restricted to a set of busses and a weighting scheme related to the MIIF values is exploited. Considering the assumptions on the MIIF values described in Section 2, the load busses that area related MIIF values lower than 0.40 can be regarded as critical nodes. The SO may be interested in calling for investments for voltage control capability in the critical nodes to increase the voltage control effectiveness.

4.1. Identification of control areas and critical nodes

The power system defined as the IEEE 10-generator (39-bus New-England) is analysed to determine each generator influence and identify the critical nodes. To this aim, the MIIF is calculated for each bus according to an iterative procedure. In each step, a different bus is selected. The voltage setpoint imposed is increased by 1% concerning the reference scenario; for each bus, MIIF is calculated according to (1) considering the difference between the current and the original voltage magnitude. Once the values of the MIIFs are computed for all busses, for each generator, the area of influence formed by the load busses is identified.

In Table 4 the MIIF values calculated for the generator busses are reported. The interaction between nodes that MIIF is lower than 0.15 can be neglected, only the MIIFs higher than this threshold are indicated in Table 4, lower values are set to zero. Table 4, the area of influence for voltage control related to each generator is determined, and 14 critical nodes are identified. In Fig. 4 the area of influence of each generator and the critical nodes are depicted. The MIIF relevant to bus 6 and bus 31 is close to 0.40. Therefore bus 6 can be excluded from the critical set.

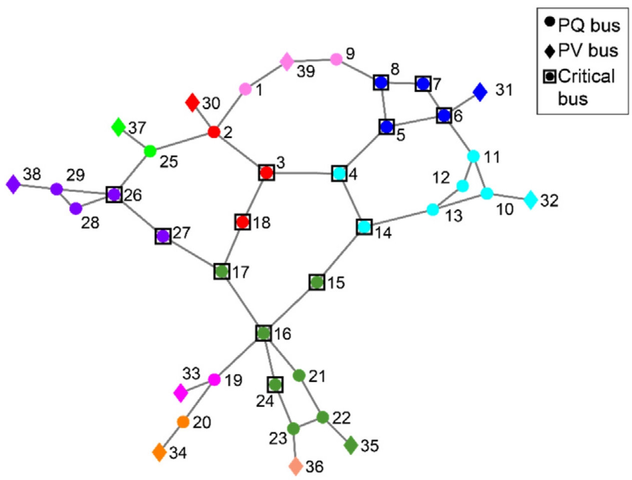

Fig. 4. Critical busses and generators' voltage control areas (IEEE 39 bus system, New-England power system).

Table 4
MIIF values for the generator busses.

Load bus	Generator bus									
	30	31	32	33	34	35	36	37	38	39
1	0.164	0	0	0	0	0	0	0	0	0.689
2	0.422	0	0	0	0	0	0	0.229	0	0
3	0.258	0	0	0	0	0	0	0.152	0	0
4	0	0.263	0.2825	0	0	0	0	0	0	0
5	0	0.372	0.3030	0	0	0	0	0	0	0.184
6	0	0.397	0.3109	0	0	0	0	0	0	0.173
7	0	0.371	0.2945	0	0	0	0	0	0	0.232
8	0	0.356	0.2844	0	0	0	0	0	0	0.259
9	0	0	0	0	0	0	0	0	0	0.700
10	0	0.249	0.499	0	0	0	0	0	0	0
11	0	0.298	0.436	0	0	0	0	0	0	0
12	0	0.279	0.455	0	0	0	0	0	0	0
13	0	0.245	0.451	0	0	0	0	0	0	0
14	0	0.228	0.338	0	0	0	0	0	0	0
15	0	0	0.182	0.187	0	0.198	0	0	0	0
16	0	0	0	0.221	0	0.234	0	0	0	0
17	0	0	0	0.167	0	0.177	0	0	0	0
18	0.190	0	0	0	0	0	0	0	0	0
19	0	0	0	0.559	0.255	0	0	0	0	0
20	0	0	0	0.305	0.582	0	0	0	0	0
21	0	0	0	0.156	0	0.412	0.179	0	0	0
22	0	0	0	0	0	0.581	0.221	0	0	0
23	0	0	0	0	0	0.406	0.388	0	0	0
24	0	0	0	0.202	0	0.260	0.169	0	0	0
25	0.283	0	0	0	0	0	0	0.4056	0	0
26	0.166	0	0	0	0	0	0	0.2019	0.377	0
27	0.158	0	0	0	0	0	0	0.1633	0.266	0
28	0	0	0	0	0	0	0	0	0.737	0
29	0	0	0	0	0	0	0	0	0.836	0

4.2. Reference costs for reactive power capacity investments

In this paper, the cost analysis considers 5 different values of the power ratio coefficient; as presented in Table 5, five values of power ratio coefficients are considered and the corresponding five value of allocation factor for investments are calculated. Moreover, in this paper, reference costs for onshore wind and PV solar power plants reactive power capacity investment are considered, as listed in Table 6. These reference costs result from the cost analysis made according to the AEP methodology [13,39] of the overnight costs outlook for 2025 reported in [70].

Moreover, the unitary cost of several devices dedicated to reactive power provision is reported in Table 7. The original values in [61] have been adapted by considering the 2019 average dollar–euro ratio equals 1.12 $/€.

Table 5
Values of power ratio coefficients and allocation factors for investments considered in the case study.

Power ratio coefficients and allocation factors for investments					
	Case A	Case B	Case C	Case D	Case E
K_{qp} [var/W]	0.1	0.2	0.3	0.4	0.5
K_q [var^2/VA^2]	0.010	0.038	0.083	0.138	0.2

Considering the possible technical restrictions in installing shunt capacitors and reactors in any node of the power system and, as discussed in Section 2, the limited dynamic response which makes them unable to provide real-time voltage control, these shunt devices are not considered technically equivalent to the other technologies; therefore, shunt devices are neglected in the case study described in this paper. Based on this assumption, the installation of synchronous condensers by the SO constitutes the cheapest network asset for providing voltage control. By considering only the costs in Tables 6 and 7, the economic viability of the investments in solar PV plants and the onshore wind can be related to a critical value of the power ratio K_{qp}. Therefore, investments which lead to a power ratio higher than this critical value are not economically viable since they are more expensive than the cheapest network asset.

4.3. The incentive mechanism

By considering the case study described in this paper, the weights K_g in Table 8 are calculated through the procedure described in Section 4.1. According to these values, the bus that shows the highest capability to influence the network voltage is bus 16; therefore, the highest weight for remunerating the reactive power capacity investments is assigned to this bus.

To illustrate, considering a power ratio K_{qp} equals 0.2, and the coefficients K_g reported in Table 8, the related weights for reactive power investments are listed in Table 9. The value of $K_{qp} = 0.2$ is chosen since it allows both onshore wind and solar PV plants to become competitive.

According to Table 9, the highest weight for investments is in bus 16 in which is recognised as a remuneration for the reactive power capability equals % of the overall power plant CAPEX. Conversely, the lower remuneration is in bus 26 in which the reactive power investment is recognised as 1.6% of the overall investment cost. In Table 10, the unitary remuneration for onshore wind and solar PV plants is calculated for both bus 16 and bus 26.

4.4. The long-term weighted auction

In the weighted auction, the additional reactive power capacity required to reinforce the voltage control has to be quantified. The SO strategies are based on the expected future scenario regarding changes in the load and generation level, security analysis, or historical data. The methods for determining the expected needs of reactive power capacity in power system planning are out of this paper scope. Thus, it is assumed that, due to load changes and power plant decommissioning, an additional reactive power capacity equals 10% of the actual capacity is required. In the initial scenario, the installed reactive power capacity is equal to 2807 Mvar; therefore, the additional reactive power to be acquired with the long-term weighted auction is 280 Mvar.

An illustrative example of the weighted auction is provided in this section. The malus coefficients calculated according to the procedure described in Section 3.2 for all the critical nodes are listed in Table 11.

Table 6
Cost analysis of reactive power capacity investment for typical DERs.

DER technology	Unitary overnight cost [70] [$/kVA]	Unitary overnight cost [€/MVA]	Case A (Table 5)	Case B (Table 5)	Case C (Table 5)	Case D (Table 5)	Case E (Table 5)
			Allocated cost for reactive power [€/Mvar]				
Onshore wind	1370	1 223,214	12,111	47,047	100,999	168,719	244,643
Solar PV	790	705,357	6984	27,129	58,240	97,291	141,071

Table 7
The unitary cost of several devices to reactive power provision.
Source: Adapted from [61].

Device	Unitary cost [$/kvar]	Unitary cost [€/Mvar]
Capacitor/Reactors	30	26,786
STATCOM	100	89,286
Static VAR compensator	100	89,286
Synchronous condensers	40	35,714

Table 8
Weights for investments and coefficients K_g related to the effectiveness of the control action.

Bus_i	$\overline{MIIF}_i$	n_i	K_{z-i}	K_{MIIF-i}	K_{g-i}
3	0.354508	23	0.884615	0.313603	0.742538
4	0.425187	21	0.807692	0.34342	0.813138
5	0.516441	18	0.692308	0.357536	0.846562
7	0.460448	15	0.576923	0.265643	0.62898
8	0.465366	15	0.576923	0.26848	0.635698
14	0.440056	20	0.769231	0.338505	0.8015
15	0.343864	22	0.846154	0.290962	0.688929
16	0.422339	26	1	0.422339	1
17	0.360775	26	1	0.360775	0.85423
18	0.31849	24	0.923077	0.293991	0.696101
24	0.334537	21	0.807692	0.270203	0.639777
26	0.372655	12	0.461538	0.171995	0.407243
27	0.327629	15	0.576923	0.189017	0.447547

The assumed price–quantity bids received for the provision of reactive power capacities are listed in Table 12. The original and the weighted prices are reported in the fifth column and the sixth column, respectively. The bids are ordered according to the increasing weighted price as prescribed by the first step of the proposed auction mechanism. The last column reports the reference weighted price related to each node. It represents the weighted cost of implementing the cheapest network asset that the SO can install. According to the values considered in the present case study and listed in Table 7, the reference asset is the synchronous capacitor.

Considering that the additional overall quantity to be procured is 280 Mvar, the set of accepted bids is represented by bids number 2, 1, 3, and 5. From Table 12, it is worth noting the extent to which the network voltage sensitivity influences the result of the market mechanism. Even if bid n. 1 (on bus 26) is cheaper than bid n. 3 (on bus 14), the effectiveness of the voltage control service provided in bus 14 is higher, and then the latter bid outclasses the former.

If a marginal price auction is adopted, the marginal clearing price reimbursed to all the winners will be 26,000 [€/Mvar]. However, if a discriminatory price auction is used, each provider will be refunded according to the price declared in the submitted offer.

Table 10
Unitary remuneration for reactive power capacity investments (overnight costs from [70]).

DER technology	Unitary overnight cost [$/kVA]	Unitary overnight cost [€/MVA]	Allocated cost for reactive power [€/Mvar]	
			Bus 16 $K_{g-i}K_q = 3.85$ %	Bus 26 $K_{g-i}K_q = 1.6$ %
Onshore wind	1370	1,223,214	47,094	19,571
Solar PV	790	705,357	27,156	11,286

4.5. Discussion

The cost-based incentive mechanism and the weighted auctions aim to stimulate third parties to invest in new reactive power capacity and provide flexibility for power system operation. The pros and cons of each mechanism influence its effectiveness when exploited in real cases.

In the cost-based incentive mechanism, once the area of interest is identified, new assets connected to the power system can be reimbursed for the reactive power capacity made available to the SO. For transparency, the weights for investment related to the network coefficients have to be open to the potential investors; hence, investment in the most effective nodes is encouraged. However, the risk of remunerating suboptimal investment exists when new providers are not connected to the node with the highest voltage influence. Moreover, the sensitivity factors must be recalculated after each accepted investment since the voltage control areas have to be redesigned. Moreover, SO plays a pivotal role because it is in charge of defining the set of incentivised busses. Finally, real costs are not revealed because the new providers are not competing, and the mechanism does not require to declare the true marginal cost. Nevertheless, a cost-based incentive mechanism contributes to hedging the risks related to the uncertainties caused by the absence of historical information about reactive power trading and limits market power abuse due to the lack of competition among providers.

The weighted auction requires to open a call for investment which time horizon has to be related to the grid development plan devised by the SO. The call for investment has to be opened enough in advance of the scheduled time of service delivery to allow investors to obtain the permits and to connect the assets (i.e. the call for investment has to be opened enough time in advance for allowing the potential investors to develop their business plan). The weighted auction encourages competition among the potential providers, and the auction allows revealing the actual marginal cost of the service without requiring any cost analysis from regulator bodies. Information asymmetry exists between the SO and third-party; however, the SO have to be declared ex-ante its potential investments, thus it is not aware of

Table 9
Weights for investments, considering the network influence and the reactive power ratio.

Bus_i	3	4	5	7	8	14	15	16	17	18	24	26	27
K_{g-i}	0.743	0.813	0.847	0.629	0.636	0.801	0.689	1	0.854	0.696	0.64	0.407	0.448
$K_{g-i}K_q$	0.029	0.031	0.033	0.024	0.024	0.031	0.026	0.038	0.033	0.027	0.025	0.016	0.017

Table 11
Weights for investments, considering the network influence and the reactive power ratio.

Bus_i	3	4	5	7	8	14	15	16	17	18	24	26	27
K_{g-i}	0.743	0.813	0.847	0.629	0.636	0.801	0.689	1	0.854	0.696	0.64	0.407	0.448
K_{M-i}	1.257	1.187	1.153	1.371	1.364	1.199	1.311	1	1.146	1.304	1.36	1.593	1.552

Table 12
An illustrative example of the uniform auction and the outcome of the weighted auction.

Bid number	Bus number	Malus coefficient	Bid quantity [Mvar]	Bid price [€/Mvar]	Weighted price [€/Mvar]	SO alternative weighted price [€/Mvar]
2	16	1.000	80	15,000	15,000	35,714
3	14	1.199	60	20,000	23,980	42,821
1	26	1.593	80	18,000	28,670	56,884
5	18	1.304	60	26,000	33,900	46,568
6	8	1.364	50	30,000	40,930	48,725
7	4	1.187	40	36,000	42,730	42,393
4	27	1.552	70	30,000	46,570	55,445
8	3	1.344	30	40,000	53,760	47,996

Table 13
Outline of the evaluation of the proposed market mechanism.

	Cost-based incentive mechanism	Weighted auction
Competition	Limited	Yes
Impact of information asymmetry	High	Medium (or low)
Level playing field	Medium	High
Exercise of market power risk	Low	Low
Complexity	Medium	Low

the bids of the third-party providers. Therefore, the competitive environment limits the SO market power. Finally, in small size markets, the risks related to market power issues are limited by the implicit reference price defined by the network assets that the SO could invest.

In Table 13, the outcome of the discussion on the features of the proposed market mechanism is resumed. The discussion highlights the pros and cons of each mechanism in light of economic efficiency.

The weighted auction enables by design the competition among potential providers, while in the cost-based incentive mechanism competition is limited.

The impact of information asymmetry related to the cost-based incentive mechanism is high. On the one hand, the weights associated with the voltage sensitivity depend on the network scenario chosen as a reference for the power system analysis addressed by the SO. On the other hand, the remuneration received by each provider depends on the declared investment costs. Therefore, a dedicated validation procedure has to be addressed by the regulator. Conversely, the information asymmetry impact in the auction is lower due to how the information is distributed to the market actors.

The level playing field guaranteed by the weighted auction is higher than in the case of the cost-based incentive mechanism since the SO competes at the same level as the other third-party providers. Furthermore, the remuneration obtained by each provider depends on its cost assessment and bid strategy. The risks related to the exercise of market power are low both in the cost-based incentive mechanism and in the case of the weighted auction. The cost-based incentive mechanism avoids by design the risk of the exercise of market power. In contrast, in the auction, the risk of market power related to the scenario in which only a few providers are competing is lowered by the SO's participation, which provides a sort of implicit budget cap.

The administrative burden of the cost-based remuneration mechanism is higher than the complexity related to the weighted auction. In the former, the responsibility of verifying the declared CAPEX is part of the regulatory oversight. On the contrary, in the auction, the burden of calculating the bids is on the providers, while the administrative burden of the related market platform has to be considered. The competing environment encourages them to bid their actual marginal costs; therefore, validation procedures on the declared costs are not required from the regulator side.

As a result of the discussion, the weighted auction outclasses the cost-based incentive mechanism since it provides higher market efficiency by requiring less regulatory burden.

5. Conclusions

This paper proposes two local market-based mechanisms to encourage the participation of new service providers in voltage support. Concerning the current practices for procuring and remunerating reactive power capacity for voltage control, the proposed cost-based incentive mechanism and the weighted auction aim to improve economic efficiency and transparency. A market mechanism that identifies the most effective provision alternatives by reducing the overall procurement cost is crucial. This paper contributes to the state of the art proposing effective local mechanisms and the related proof of concept in realistic power system scenarios. Both mechanisms are based on economic efficiency principles, the selection and the remuneration for the investments is based on the volume of the need and the effectiveness of the contribution. In the proposed mechanisms, the remuneration of the service providers tends to the actual marginal cost of the service provision, third-parties compete in a level playing field with other voltage support service providers and traditional network reinforcement alternatives.

A cost-based incentive mechanism and a weighted auction are proposed to allow the SO in procuring the additional reactive power capacity required for operating the power system. The cost-based mechanism edges the uncertainties related to the lack of historical information about reactive power costs and prices since any market mechanism is currently implemented. However, it requires verification of the declared investors' costs to avoid the risk of providing biased incentives. The weighted auction involves both third-party providers and the SO in a competitive environment which induces the market participants in bidding their actual marginal costs. The SO provides a reference price that limits the risks related to the market power issues. However, the call for investments has to be opened enough in advance to allow the potential providers to conclude the authorisation and construction process. The weighted auction is more appealing than the cost-based incentive mechanism for the expected high degree of competition and level playing field. Furthermore, the regulator does not have to verify the investors' cost or define coefficients for splitting the reactive power CAPEX from the overall investment with the market scheme. However, both mechanisms may be applied to real cases by previously adapting their features to the local characteristics. In any case, a penalty scheme is required for the new providers that fail in meeting the deadline for providing the service.

Since the lack of historical economic information related to the absence of reactive power markets, both proposed mechanisms are long-term based on edging the uncertainty and associated risk. Furthermore, long-term procurement enhances the competition since it allows new service providers to invest in delivering the service when required.

The proposed market mechanism can integrate the mandatory service provision and be employed in transmission and distribution systems. Moreover, it can be scaled up and down in terms of the order of magnitude of the total amount of service required. It is open to all technologies and actors capable of providing reactive power capacity (e.g. single power plants, aggregated resources).

Future research will focus on applying the proposed market mechanism to real systems to define business cases to quantify the economic performance and the implementation costs. Moreover, it is of interest to extend the formalisation of the proposed mechanism for procuring congestion management capability. Congestion problems share some degree of similarity with voltage problems due to the local characteristics of the service.

CRediT authorship contribution statement

Matteo Troncia: Conceptualisation, Methodology, Investigation, Writing, Visualisation. **José Pablo Chaves Ávila:** Conceptualisation, Methodology, Validation, Resources, Writing, Supervision. **Fabrizio Pilo:** Conceptualisation, Validation, Resources, Writing, Supervision. **Tomás Gómez San Román:** Conceptualisation, Validation, Writing, Supervision.

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.

Acknowledgement

The authors thank the comments received from Daniel Daví from e-distribución.

Funding

Fabrizio Pilo and Matteo Troncia are co-financed by the Research Fund for the Italian Electrical System under the Contract Agreement between RSE S.p.A. and the Ministry of Economic Development in compliance with the Decree of March 8, 2006.

Fabrizio Pilo's research was also funded by the Italian Ministry for University and Research under the grant agreement PRIN-2017K4JZEE "Planning and flexible operation of micro-grids with generation, storage and demand control as a support to sustainable and efficient electrical power systems: regulatory aspects, modelling and experimental validation".

Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.segan.2021.100507.

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