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Voltage Control Market Integration: Technical and Regulatory Challenges for the Greek Electricity Market

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Abstract: Stochastic power generation is the new reality in power system management. Voltage Control mechanisms based on physical assets of the power system are deemed inadequate and are not guaranteed to lead the energy transformation in a way that ensures system security as well as cost-effective operation. Many countries that recently attained deregulated Balancing Market environments are in need of regulatory provisions and rigorous extension of electricity market mechanisms. On 1 November 2020, the Greek Electricity Market commenced operations conforming to the European Target Model. Apart from the innate difficulties a transformation such as this contains, more challenges occur as Greece is bound by European law to design market-based incentive mechanisms to remunerate Ancillary Services provided to the power system. This paper aims to examine some of the technical and regulatory aspects linked with—future—Transmission System Operator (TSO) and Distribution System Operator (DSO) cooperation in overcoming local transmission system problems concerning Voltage regulation. The interaction between localized Voltage Control Market (VCM) and the Balancing Market, the incorporation and competition of Distributed Energy Resources (DER) and Transmission Energy Resources (TER) within the VCM along with the TSO - DSO procedures and products standardization are the focus points of the present research paper.

Keywords: voltage control; energy markets; ancillary services; TSO/DSO coordination; Transmission System Operator; Distributed Energy Resources

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1. Introduction

On the journey towards transitioning to renewable generation and participatory consumption mechanisms, as well as exploring new decarbonization pathways, the Greek power system is on the brink of implementing the Ancillary Services' Market (ASM) to support the shift towards a paradigm with distributed generation in the epicenter [1]. While the integration of distributed renewable generation to the existing power systems structure can entail major challenges [2], it can also provide new solutions to long-lasting unresolved issues of power systems, such as congestion management [3], voltage control [4], controlled islanding [5] and black-start services [6] all while engaging small and larger scale producers to the process [7]. From the System Operators' perspective, both Transmission and Distribution, as technical, regulatory and safety compliance of the new paradigm, must be guaranteed for the services provided.

From a technical perspective, the integration of DER stumbles upon the intermittency of power generation and the challenge of effective, accurate and immediate communication between the actors managing the power system. First of all, the main advantage of DER, forming a micro-grid, that being dual-mode operation, meaning switching functionality between island mode and grid-connected [8,9] can also be a major challenge. Furthermore, maintenance of frequency and voltage quality can disrupt the standard processes of both the transmission grid, where ramping availability must be guaranteed by new balancing and frequency services, and the distribution grid, where new flexibility services and investments by the distribution system operators (DSOs) are required to handle reverse power flows, as well as new congestion and voltage issues [10]. Finally, from the standpoint of safety and protection of equipment, standards similar to those implemented by TSOs over the span of the previous decades will have to be met, both for generators and consumer equipment as well [11].

Integrating DER requires rigorous effort in updating and implementing a renewed regulatory framework. There is a broad consensus between associations on the importance of updating the regulatory framework towards the active management of the power system without excluding DER participation in markets [12,13]. The strive for a solid and efficient regulatory framework is conducted on two fronts, which can produce conflicting results. On the one hand, European institutions and legislators promote guidelines on DER integration that is being developed in a fast and consistent manner but disregard the capacity of national authorities ability to keep pace with the changes, resulting in the addition of new regulations atop existing ones, called "layered" regulation [14]. On the other hand, system operators offer a technical approach to regulatory provisions emphasizing more on engineering based strategies and principles focusing on system routines such as grid optimization, power flow, control system designs, ultimately reinforcing the overall system security and resilience. The effort of both system operators and European institutions burdens national authorities with different inputs that result in delays in harmonising the national regulation.

As was preemptively forseen in E.DSO position paper [15] on DSO's future role in the power system, distributed generation (DG) would become the enabler for DSO Ancillary Services' provision in the near future.

This paper aims to examine some of the technical and regulatory aspects linked with Transmission System Operator (TSO) and Distribution System Operator (DSO) cooperation in overcoming local transmission system problems concerning voltage regulation. At the centre of the TSO/DSO coordination is the use of flexibility service providers connected to both operators who can participate in a market-based environment to provide the voltage regulation service. A key contribution is the development of the voltage control market in which the market agents can participate by providing the necessary service. The abovementioned voltage control market was integrated as a simulated component in the dispatch operation of the Greek TSO, and its operation was tested using demonstration data. In addition, of significant importance is the comparison of two different coordination schemes for operators and how the availability of flexibility can change the outcome of the voltage control market. The paper has the following structure. In Section 2, the methodology of voltage regulation in a market-based environment is presented. The focus of the methodology is on describing the coordination schemes that will be compared. The operation of the Greek TSO balancing market and the integration of the voltage control market in the Greek TSO's current practices are described in Section 3. Section 4 presents the results from the operation of the voltage control market for the demonstration site. Extreme scenarios using realistic data are tested so that the business-as-usual operation can be compared with the market-based coordination schemes. A detailed discussion is also followed. Conclusions are drawn in Section 5.

2. Methodology

In this section, a brief presentation of the practices and techniques used by Greek System Operators to regulate voltage in their corresponding control area of the power system is included, followed by an analysis of the two greater categories of market designs with regard to the integration of voltage control market and the technical and regulatory challenges derived from each design classification.

The market designs proposed in this paper are: a disjointed market design with the identifying name *fragmented* market design and a cooperative design with the identifying name *Multi-Level* market design.

The technical aspects of Voltage regulation are subject to several physical operating boundaries [16]. Since the introduction of micro-grids, hierarchical voltage control has been a dominant concept in voltage regulation. The hierarchical model divides the control layers into three distinct categories, each with its own locational, regulatory and operating boundaries. In [17], the voltage control level definitions are given as follows:

1. Primary control: It is the first level in the control hierarchy and has the most localised properties. It adjusts the voltage reference provided to the inner current of the generator and voltage control loops.
2. Secondary control: The following level, set between Primary and Tertiary control, has as its main focus regulating the problem of the voltage or current deviation.
3. Tertiary control: The top level of the control hierarchy is where the management ensures the optimal operation of the micro-grid at the system level is realised.
   Since its realization, the hierarchical model introduced a cooperative way in which the SOs could communicate to regulate voltage bilaterally

The proposed methods described subsequently introduce the ideal technical conditions to promote market-based mechanisms to regulate voltage by utilising the hierarchical voltage control concept.

In [18], the management of Low Voltage micro-grids is proposed to enable the creation of a Voltage Control Market supervised by the DSO without provisions about the interaction with the TSO. The proposed technique suggests the aggregation and common management of micro-generators in a hierarchical order.

Furthermore, [19] denote the use of blockchain technology in procuring flexibility services triggered by TSO signals and to Aggregators and/or Energy Communities without the DSO operating a separate local market. The DSO's role in this market design is limited to providing the metering infrastructure, the MV, and LV network and input on the local grid constraints.

2.1. Current Practices in the Greek Power System

Historically, voltage control practices in the Greek power system are based on the notion of reduced volatility of production. Voltage control in the Distribution System is not a provided ancillary service of the electricity Market and is achieved through legislative provisions implemented by the DSO, as well as electrical assets fit into the distribution system. The Transmission System, although operating in a deregulated environment, has yet to develop a VCM, with the TSO invoking its right to derogate the process according to Commission Regulation (EU) 2017/1485 [20]. The TSO can use proprietary electrical assets of the transmission system and legislative means to regulate voltage.

At the distribution level, the absence of a market-based mechanism for ancillary services, along with the uniqueness of the Greek power system with 29 non-interconnected island power systems, narrows the options of the DSO in uniformly managing the power system. The capabilities of the DSO are very limited in terms of intervention to distribution load and generation; thus, it mostly relies on its physical assets to procure voltage control and other ancillary services. According to Greek Distribution Network Code/2017 Section II, Ch.4,Ar.18 [21], the DSO relies on the following assets to regulate and control voltage: three-phase circuit breakers, automatic circuit breakers, disconnectors, automatic disconnectors, fuses, automated and manual off-load and on-load tap changing transformers, automatic voltage regulators and static VAR compensators. The right of the DSO to invoke a dispatch order to generators in the distribution system is also established in the aforementioned Network Code.

To this day, the TSO regulates voltage needs through dispatch orders [22], mostly invoking them in cases where operational stability needs to be secured. The receiving party of each dispatched order is a generator unit, and the period of validity of such an order is a

Real-Time Balancing Market period (15 min), if not otherwise stated. Although, the exact circumstances of issuing dispatch orders are not publicly available, dispatch orders are issued with respect to the Integrated Scheduling Process (ISP) and the operation of the Real-Time Balancing Market. Dispatch orders for voltage regulation should include an explicit value of the voltage or reactive power on the connection point of the unit with the transmission system. The TSO should act, taking into account any differentiation a dispatch order may provoke in the unit's active power production.

On the upside, this market design does not introduce further constraints on the overall objective function of the power system. The dispatch orders methodology is non-market in the sense that it is not compensated as a service, but rather, any fluctuations created to the production units are reimbursed based on the deviations of the unit's commitment to the ISP and only for active power. Optimising the procurement of power and flexibility is next to impossible for this kind of design since flexibility procurement is addressed as a liability or side-effect of the operating system and not as an innate feature.

2.2. Voltage Control in Disjointed Market Design

To ensure economic optimisation and secure the access and participation of all energy resources in the system, especially providing flexibility services, several Market Models have been proposed. A Disjointed Market Design became known as a Model where each operator is responsible for managing its own power system, utilising resources provided only for the assets connected to its own system. A simple conception, yet particularly capable of facilitating market access to Distributed Energy Resources.

To facilitate the transfer of active power throughout the power system, the voltage should be limited within the operating margins. Given its localised properties, Voltage Control services are feasible for local market creation and operation.

The design of the disjointed Voltage Control Market was based on a sequential procurement practice. The System Operators have knowledge of the grid needs at different moments in time; thus, different timeframes for market clearance and procurement are proposed. The involvement of the DSO in Ancillary Services Markets is believed to contribute to the rationalisation of the power system's resource usage.

In [23–26], several versions of a disjointed market design are presented. Despite the differences in terminology, a general classification is introduced in the following Table 1:

Table 1. Disjointed Market Designs for a Voltage Control Market as identified in European Research Programs.

Market Design	Advantages	Criticalities
Central Market Model	In a single buyer system, it can ensure optimal efficiency. Straightforward market processes and low operational expenses are guaranteed in the single buyer market. Common case for European Energy Markets	DSO remains uninvolved in market procedures. Input from DSO is not always facilitated.
Fragmented Market Model	Local criteria in flexibility procurement. DSO actively supports AS procurement. Reducing or eliminating hurdles for equal participation of small scaled DER.	Sequential market clearing from both operators. Scarcity of offers for Local markets. TSO-DSO local market operator coordination needs.
Distributed Flexibility Market Model	Aggregators can solve imbalances in the scope of their own portfolios. Increased amount of offers with a high probability of competitive prices due to a large number of market participants.	Independent market operator needed to operate the market platform. Liquidity of intraday markets is transferred on the local level. TSO-DSO local market operator coordination needs.

Disjointed market designs introduce separate objective functions for each power system operator. Each operational level functions independently with respect to its own separate objective function and constraints, taking into account multiple factors such as unit production, grid components, consumption profiles and transfer capacity. Although each objective function can be optimised for the appropriate operational level, the system's overall optimum might not always be achievable through the method of independent optimisation of separate objective functions.

2.3. Voltage Control in Co-Operational Market Design

The arising challenge of contemporary power systems is the efficient coordination of multiple DER to regulate voltage levels while achieving the least amount of generation curtailment [27]. Additionally, efficient voltage management of both transmission and distribution network(s) requires streamlined coordination between the TSOs and DSOs as both networks become more intertwined. Technological advancements and the need of consumers for adequate self-generation guide the trend of investing in DER connected to the distribution network, which gradually replaces reactive power sources linked to the transmission network; this presents a significant issue and calls for greater active involvement of assets in the distribution network in transmission network's voltage support.

In many European research programs, co-operational Voltage Control Market designs are sufficiently described, a non-exhaustive list is the following [23–26]. The conceptualization of the current trend in the several divisions of the co-operational electricity market designs traces back to [28]. Gerard et al. provide a sufficient abstraction to discard unnecessary technicalities that lead to the fragmentation of sub-designs. The dominant distinction is presented in Table 2.

Table 2. Co-operational Market Designs for a Voltage Control Market as conceptualised in Gerard et al.

Market Design	Advantages	Criticalities
Common Market Model	Flexibility is allocated to the system operator with the highest need. Common market for flexible resources connected to the transmission and distribution grid.	Both TSO and DSO are buyers in this market. In large markets, the optimization process becomes mathematically heavy.
Integrated Flexibility Market Model	System Operators and markets parties simultaneously engage in a common market. Allows direct competition between regulated and non-regulated players. System Operators can resell unused flexibility back to the market at the contracted price, reinforcing market liquidity.	Non-regulated players require the introduction of an independent market operator to guarantee neutrality. Additional interaction between system operators and the independent market operator. Additional procedural complexity.

In co-operational market designs, several new constraints are introduced to the objective function of the system. Apart from the innate difficulties involved in a transformation such as this, more challenges occur as Greece is bound by European law to design market based incentive mechanisms to remunerate Ancillary Services provided to the power system. Information flows must be constant and steady but without overwhelming the system operators and involved parties. The system can be very complex, and redundant information can unnecessarily burden calculations.

3. Voltage Control Market Description

As it was described in Section 2, the VCM operates near real-time before the final solution of the Real-Time Balancing Market (RTBM). For the purposes of our study, a validation tool of the RTBM of Greece has been developed, which is presented in Figure 1.

In Section 3.1, the validation of the RTBM validation tool of the Greek power system is presented, and in Section 3.2, the service-based voltage control market is described in detail.

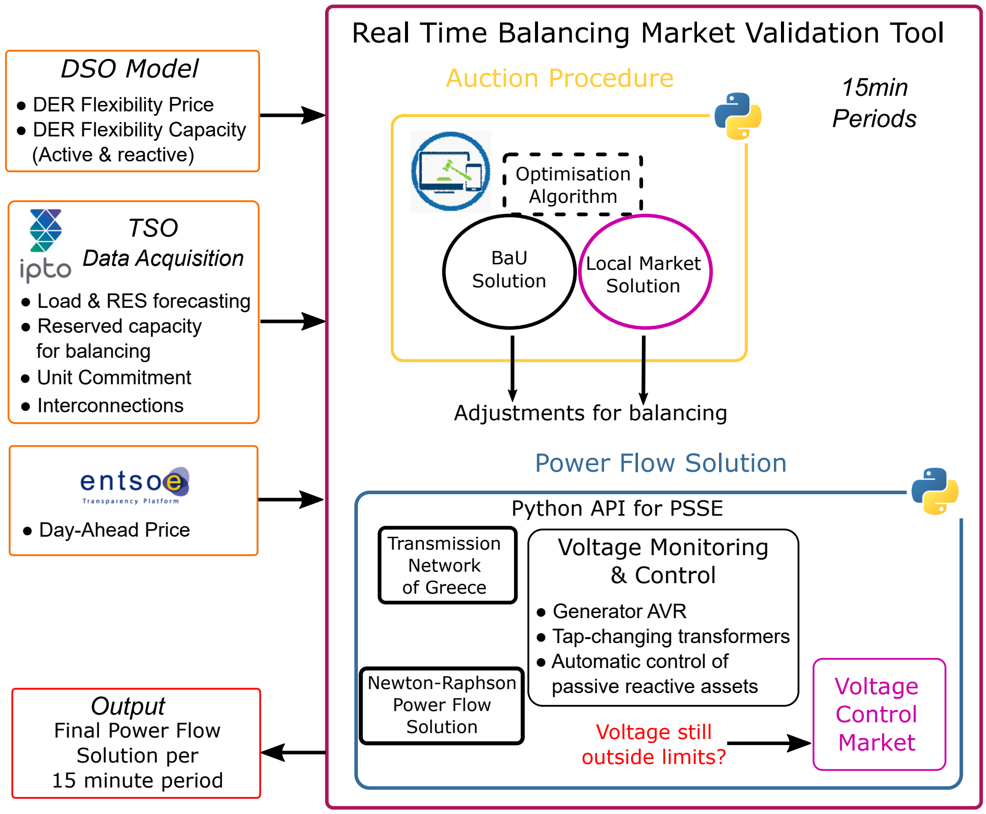

Figure 1. Architecture of the Real-Time Balancing Market Validation Tool.

3.1. The Real Time Balancing Market

The RTBM Validation Tool can generate snapshots of the state of the power system of Greece every 15 min. The power system model used is similar to the actual power transmission system of Greece and consists of:

- Overhead transmission lines are 400 kV, 150 kV or 66 kV. Submarine transmission lines are 400 kV or 150 kV.
- 732 transformers and auto-transformers. Transformers can be 150/20 kV to connect with the DSO or 400/150 kV at the extra high voltage substations.
- 331 Substations which are represented as 1492 buses.
- Interconnections between Greece and North Macedonia, Albania, Italy, Bulgaria and Turkey.

The model is simulated in the PSSE software [29]. Detailed information regarding the design and operation of the RTBM Validation Tool can be found in [30]. The validation tool operates as follows:

1. The Day Ahead Business as Usual (DA BaU) solution is loaded as the starting point of the power system of Greece.
2. The forecasted load demand and RES production for the next 15 min period are calculated. The new real-time values of load demand and RES production are imported to the PSSE model, and a new solution is acquired using the full Newton-Raphson method.
3. Conventional approaches to control voltage are used, such as the Automatic Voltage Regulation (AVR) of generators, tap-changing of transformers and automatic control of passive, reactive assets.

4. If the voltage of an HV bus is still outside the limits, then the VCM is enabled. The flexibility service providers that can participate in the VCM of the transmission system depend on the market model used as described in Section 2 and the location of the flexibility service provider, hereof FSP(s). FSPs closer to the voltage violation can have a greater effect compared to FSPs further away. This can be determined by the network voltage sensitivity factors. In this paper, the PQ flexibility maps [31] will be used and are described in Section 3.2.
5. In the Fragmented Market Model only, load and RES connected at the transmission network can participate. In the MultiLevel Market Model, flexibilities at the distribution network can also participate in the VCM of the transmission network.
6. The output of the VCM is a change in the active and reactive power of the FSPs that participate. The changes take place at the RTBM Validation Tool, and a new state of the power system is acquired. In addition, the RTBM Validation Tool resolves any imbalances created by the operation of the VCM. At this point, for the balancing of the system, an additional constraint is created to activate the available reserved capacities for balancing without causing a voltage violation in the same area.

The interactions between the RTBM Validation Tool and the VCM are described in Figure 2:

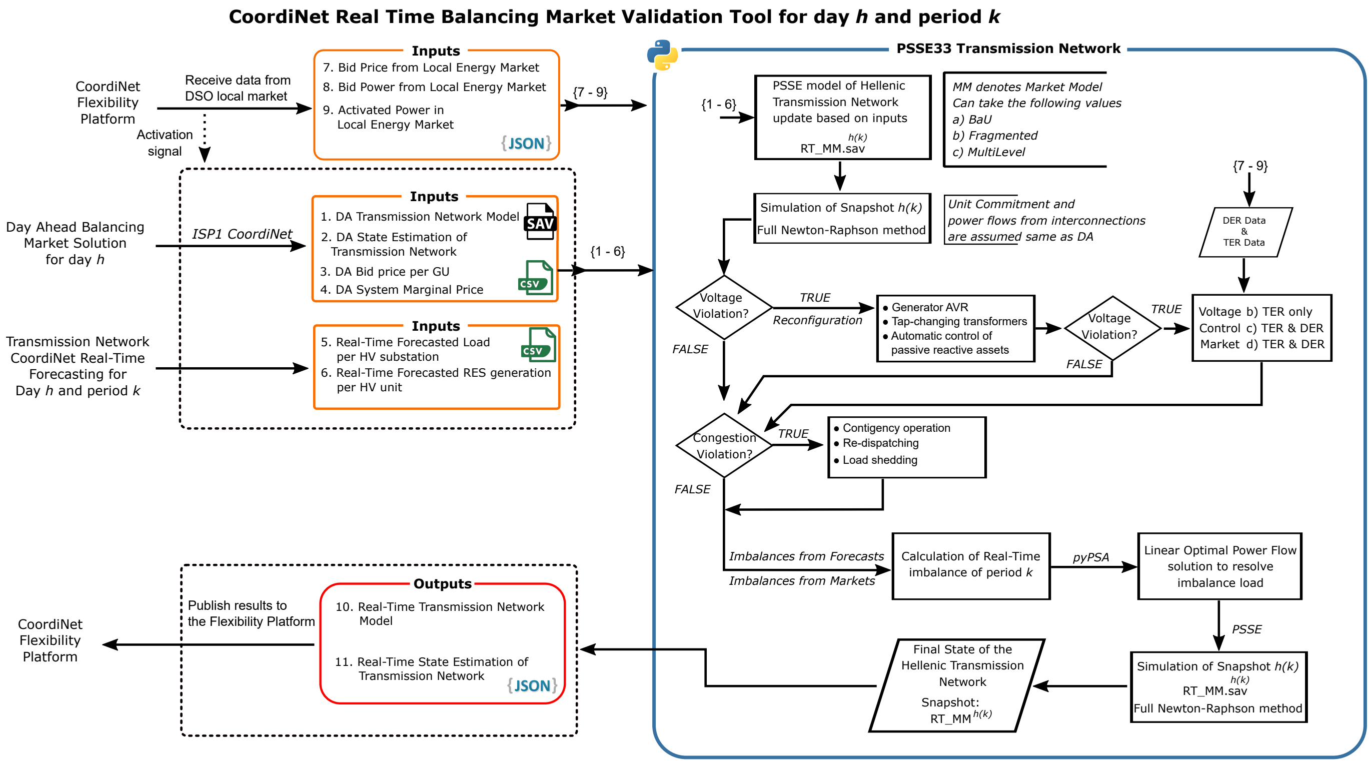

Figure 2. Architecture of the Real-Time Balancing Market Validation Tool.

3.2. Voltage Control Market Formulation

The VCM is enabled when a voltage violation cannot be resolved using conventional methods of voltage control, such as Automatic Voltage Regulation (AVR) of generating units and automatic control of passive, reactive components. The operation of the VCM is presented in Figure 3. It has to be noted that the VCM implemented in this paper only considers steady-state reactive power products.

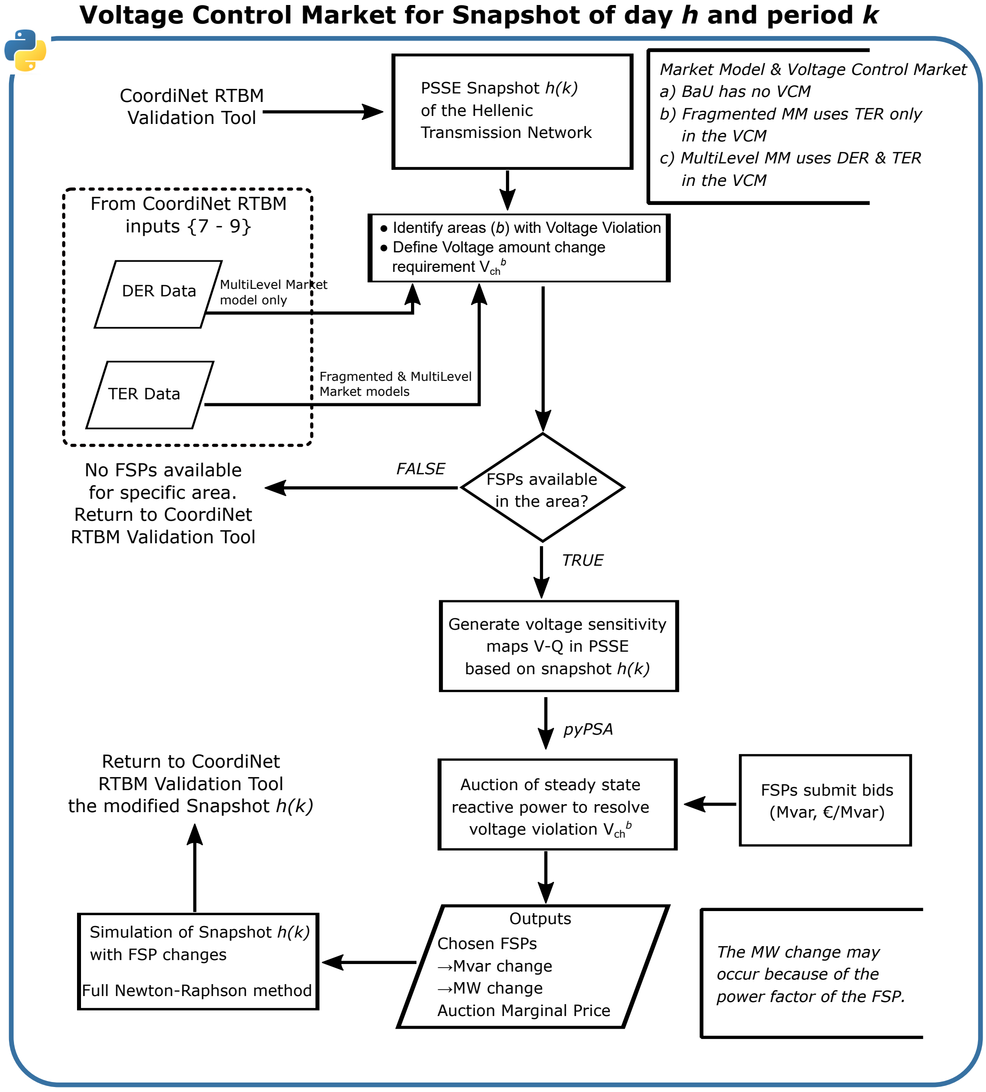

Figure 3. Architecture of the Voltage Control Market.

The VCM accepts as inputs the snapshot from the RTBM, where the voltage violation cannot be resolved, and the flexibility data (DER and TER data) that come from the flexibility platform. The FSPs that can participate in the market depend on the location of the voltage violation. Voltage, unlike frequency, is a locational parameter and, therefore, only FSPs close to the voltage violation can participate in the VCM. If there are no FSPs available in the specific area, then the VCM exits, and the RTBM continues operation. For each area of the transmission network, there is a specific registry of FSPs and their location that can participate in the VCM.

In addition, from the RTBM snapshot, the voltage requirements are defined as voltage change in the HV bus b. Assuming there are FSPs available to procure flexibility to resolve the voltage violation, the voltage sensitivity factors (VSFs) are generated using PSSE. The VSFs for each FSP at a specific snapshot affecting the bus with the voltage violation can be depicted using the flexibility maps [31]. An example of a flexibility map for a wind farm connected at the transmission network can be seen in Figure 4 (right) and for an aggregated demand response from DERs at the distribution grid in Figure 4 (left).

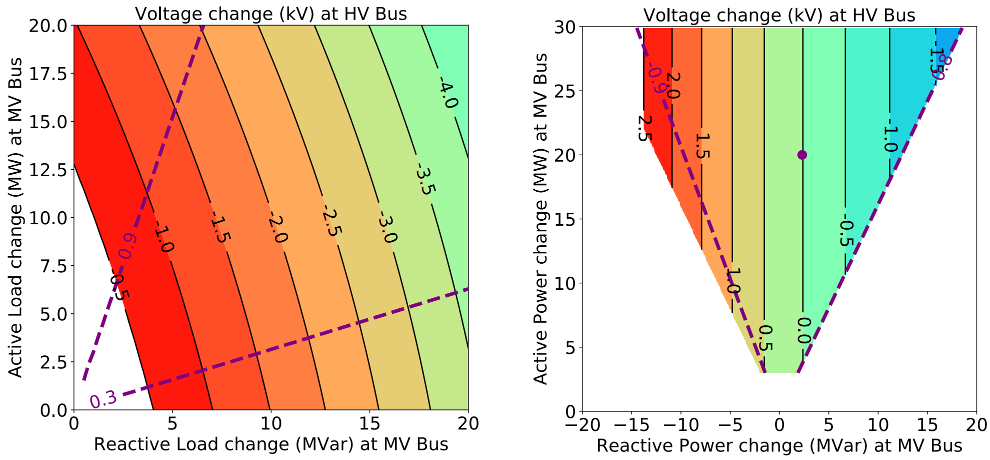

Figure 4. Example of flexibility maps for aggregated demand response load at the distribution level (**left**) and wind farm connected at the transmission level (**right**)

As it is depicted in Figure 4 the voltage change depicted refers to the HV bus of the transmission network. The changes in reactive and active power (x and y axis, respectively) occur at the location of the FSP that participates in the VCM. In the case of demand response from DERs (Figure 4 (left)) the possible changes of reactive and active power depend on the capabilities of the aggregated load. Therefore, Figure 4 (left) shows how the increase in reactive and active load at the MV side of the transformer reduces the voltage at the HV side of the transformer. The possible changes in the aggregated load may require following a specific power factor range. Therefore, the bids submitted from DER FSPs can be translated to voltage change at the HV bus of interest. A similar process is followed for the FSPs connected to the transmission network. Figure 4 (right) shows the flexibility map of a wind farm FSP which is restricted by its current operating point (purple dot) and power factor range.

The VSFs, transmission system voltage requirements and FSP bids are all used as input to the auction procedure, which is implemented in the Python library pyPSA [32]. The clearing algorithm of the VCM is based on the merit order process and can be formulated as an optimisation problem with the following objective function (1):

$$\min_{\tilde{\pi},p_i} C_{total} \quad where \quad C_{total} = \sum_{i=1}^{I} [\tilde{\pi} * (p_i * VSF_i^b)] \tag{1}$$

Term p_i*$\mathrm{VSF}_i{}^b$ determines the effectiveness of flexibility offer i in changing the voltage at the desired bus b and its units are [kV]. Variable $\tilde{\pi}$ is the market clearing price for a snapshot *h(k)* and is determined by (2):

$$\tilde{\pi} = max\{O_i(p_i)\} \quad \forall\, i \tag{2}$$

The above equations are subject to energy offers that are positive and that total auctioned system demand of voltage change $V_{ch}{}^b$ is covered by the optimisation problem:

$$p_i \geq 0 \tag{3}$$

$$\sum_{i=1}^{I} VSF_i^b p_i = V_{ch}^b \quad \forall\, b\, \in N \tag{4}$$

Bids from FSPs are submitted in pairs (Mvar, €/Mvar) since only steady-state reactive power products are accepted in the VCM. The pairs of reactive power and cost of the reactive power unit (Mvar, €/Mvar) can be converted to pair of voltage changes in kV and cost per kV of change as (V_{ch}, €/V_{ch}). The conversion from reactive power provision to kV change for each FSP can be realised using the V-Q flexibility map diagrams, which were presented in Figure 4. The flexibility offers that combine both technical and economic efficiency are activated and cleared in a pay-as-cleared manner at a price $\tilde{\pi}$. We consider that this process takes place for each optimization horizon that TSO requests for flexibility for the set of specific buses where FSPs are available. Therefore, the payments to the market participants, i, are allocated using the voltage change in kV (V_{ch}) each participant contributed and the market clearing price for each specific market horizon k. So, for each market participant, the profit is calculated as $\tilde{\pi} * (p_i * VSF_i^b)$. For each market horizon, the total cost C_{total} incurred to the TSO for activating the VCM can be calculated by summing the profits from all the market participants.

Apart from the reactive power change that the VCM decides based on economic and technical efficiency, active power changes may have to take effect. Depending on the technology of the FSP, active power may have to be injected or absorbed together with reactive power. Though active power is not included as a separate bid, it will affect the voltage regulation process, as shown in Figure 4 as well as in the imbalance calculation of the RTBM.

The changes that the VCM auction process clears are used to update the PSSE Snapshot *h(k)* and to simulate it using the full Newton-Raphson method. Then the RTBM Validation Tool continues operation as usual and proceeds to the checks for congestion management and optimal power flow to resolve imbalances.

4. Case Study

We apply the methodology described in Section 3 to a case study in Greece. Specifically, the demo site of Kefalonia (Figure 5), and its Argostoli MV/HV substation (black triangle in Figure 5) is selected as a test-bed. Argostoli MV/HV substation serves the loads of the whole island.

The power system of the interconnected island complex of Zante, Kefalonia and Lefkada has several features which render it ideal for a demo site for voltage control. These features include:

1. The islands are interconnected with three HV submarine cables which can cause excess reactive power flows. Currently, reactive power lagging compensation apparatus is used to deal with the reactive power flows in the area.
2. In addition to the Argostoli MV/HV substation to meet the load demand, Kefalonia is the only island with an HV RES substation (MYRTOS blue triangle in Figure 5) with operating wind farms. Therefore, TER will be able to participate in the VCM.
3. All the islands have a large seasonal load variation. During the summer months, the islands reach peak load, which can cause undervoltages, whereas, during spring and autumn months, the load can even become negative for a period of time due to increased distributed generation. The negative load at the distribution side, in addition to the increased RES generation from the nearby wind farms, can cause overvoltages.
4. Most islands of the interconnected power system of Greece have a similarly developed network and, therefore, methodologies developed for Kefalonia could be replicated to other islands as well.

For the purposes of the research demonstration, two scenarios were studied. The first scenario assumes low load and high RES production at both distribution and transmission levels. In the low-load/high-RES scenario, we are expected to monitor and regulate overvoltages. The second scenario assumes a day during summer when the load is at its maximum. For the high-load scenario, we are expected to monitor and regulate undervoltages.

The Ten-Year Development Plan of the Greek power system is always considering and anticipating worst-case scenarios. Therefore, the current infrastructure is reinforced to deal with all types of uncertainties and contingencies that may arise. For the purposes of the research study and to create virtual undervoltages and overvoltages, the voltage limits for the Argostoli HV substation were set to stricter levels. That way, the VCM will be enabled in the above-mentioned scenarios.

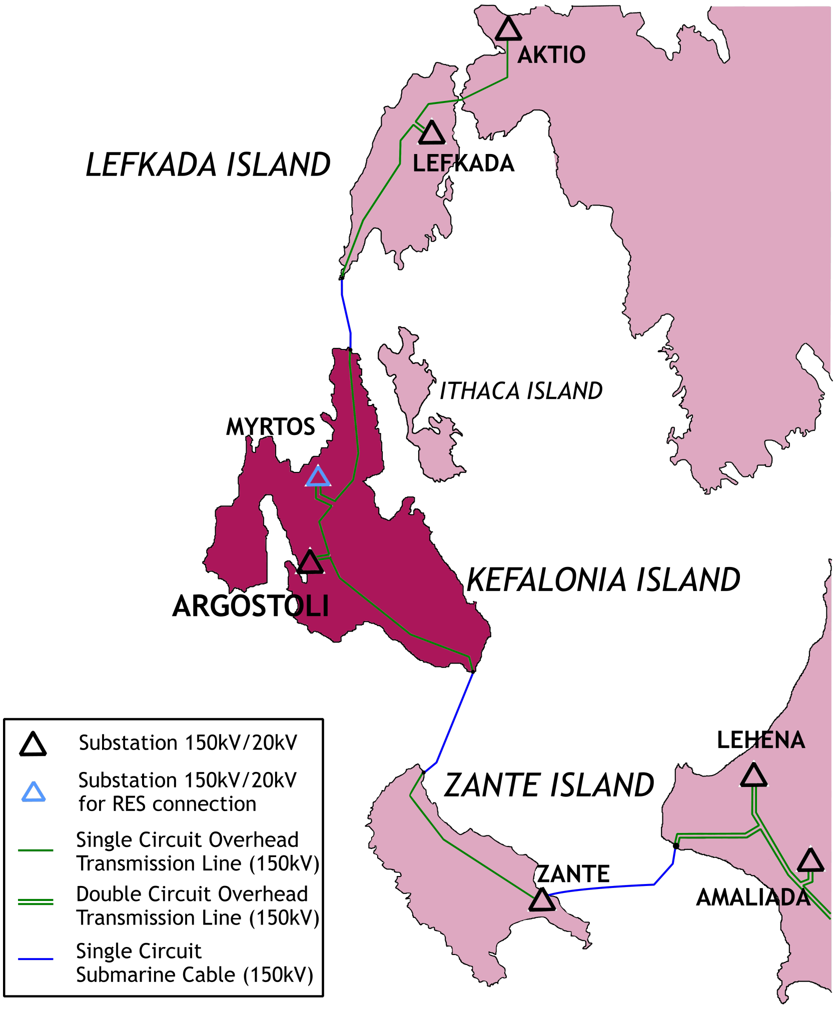

Figure 5. Map of the TS in the broader area of Argostoli HV Substation [33].

4.1. Scenario 1: Low Load-High RES Production (Overvoltages)

The first demonstration assumes days when the load is low and RES production at both distribution and transmission levels is high. At Kefalonia island, this is common during springtime due to the fact that there are no requirements for heating or cooling, and at the same time, it is an off-season for tourism. Therefore, at the MV/HV Substation of Argostoli, the net load can take negative values leading to inverse power flows, i.e., active power flows from the distribution network to the transmission network. The excess power from the distribution network increases the voltage at the substation. Another case in which overvoltages can take place is during the beginning of summer. The time window of PV generation is larger compared to other times of the year. Especially during early morning times when the net load is still low, the excess PV generation can significantly increase the voltage. In addition to the above regarding RES generation from PVs, a number of large wind farms are connected to the transmission network in Kefalonia. Power generation from wind farms during times of low or even negative net load can also cause the increased voltage at the Argostoli substation.

Figure 6 depicts the voltage at the Argostoli substation during a day in the spring of 2022. The voltage at the BaU case (blue line) is above 1.06 pu, which is a stricter limit than the one defined within the Greek regulation and is set for the purposes of this demonstration for approximately 12 h. During that time, the generation output from the wind farms was at its maximum, and because the load is low during the night and early morning, the voltage was above the limit. The overvoltage problem worsened in the morning due to increased power generation from PVs at the distribution level. The voltage increased from 1.065 pu to nearly 1.08 pu (which is the actual voltage limit provisioned in the Greek regulation) between 06:00 and 10:00. The increased load after 10:00 dropped the voltage below the limit of 1.06 pu. A minor overvoltage also appeared at 16:00 for a 15 min period.

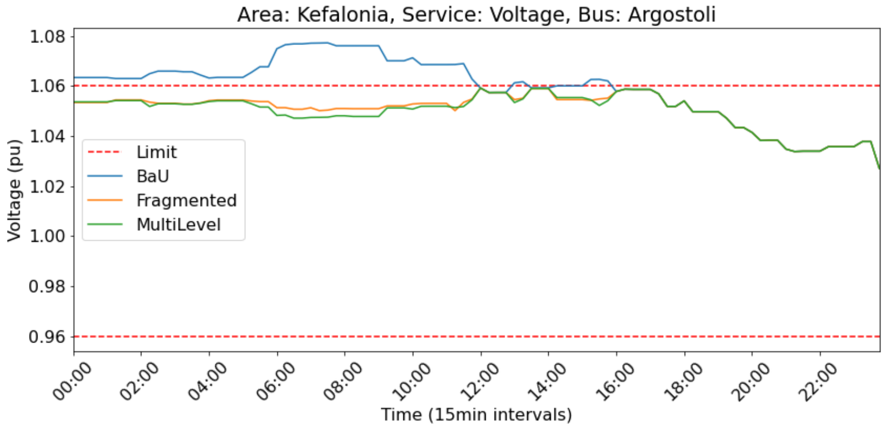

Figure 6. Example of a daily voltage variation at Argostoli substation during springtime.

The overvoltages that appeared in the BaU scenario can be mitigated with the VCM that was described in Section 3. Both the Fragmented and Multi-level cases managed to reduce the overvoltage below the limit of 1.06 pu. The main difference between the two cases is that in the Fragmented case, only the transmission-connected wind farms can participate in the VCM, whereas in the Multi-level case, distribution and transmission flexibility can participate in the market.

Figure 7 depicts the voltage at Argostoli substation during a day in June of 2022. The daylight window in June is about 3 hours larger compared to the daylight window in spring. Similarly to the previous graph, the overvoltage appears during the early morning hours when the load is loaded, and PV generation starts to appear. In addition, two small overvoltages also appear between 17:30 and 21:00. This is related to the decreased net load and the fact that PVs are still generating at that time during June.

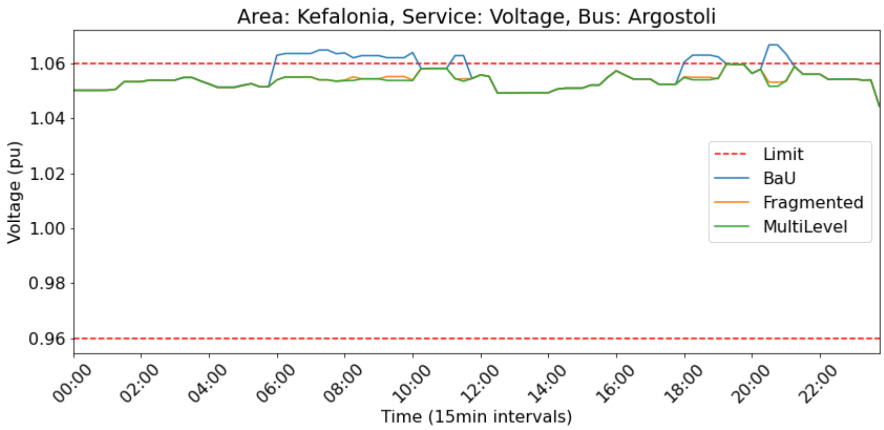

Figure 7. Example of a daily voltage variation at Argostoli substation during the beginning of summertime.

4.2. Scenario 2: Maximum Load (Undervoltages)

The second demonstration scenario assumes days when the load is at its maximum, and RES production at both distribution and transmission levels is low. On Kefalonia island, this is common during summertime. This is because Kefalonia and nearby islands are tourist destinations and the load of the island can increase threefold. The significant increase in the load is due to the increased population and the significant cooling requirements. Therefore, at the MV/HV Substation of Argostoli, the net load can take very high values leading to significant active and reactive flows. However, during the summer, PV generation is also at its maximum which somehow balances the increased demand during the day. When the PV generation drops during the night, the voltage at the substation can drop which can lead to undervoltages.

Figure 8 depicts the voltage at Argostoli substation during a day in mid-August of 2022. As described above, during the day, despite the increased cooling requirements, voltage is balanced and within limits because of the increased PV generation. However, as the sunlight is decreasing the voltage drops because of the increased load demand from tourism. This can even lead to undervoltages in the BaU scenario as it is depicted in Figure 8. Between 00:00 and 03:00, voltage is below the 0.96 pu limit, which is a stricter limit than the one provisioned in Greek regulation and was set for the purposes of this demonstration. The undervoltages that appeared in the BaU scenario can be mitigated with the VCM that was described in Section 3. In the Fragmented Market Model, in which the VCM can only use transmission-connected flexibility providers, the undervoltage is still present. The Fragmented Market Model did not manage to mitigate the undervoltage and only increased the voltage by approximately 0.005 pu. This is because the wind farms that participated in the market were only producing a small fraction of their rated active power. Based on the analysis presented in Section 3.2 and in Figure 4, the reactive power that wind farms can provide heavily depends on its active power output. Therefore, the transmission-connected wind farms could only provide a very small amount of reactive power at the VCM, which only causes a small change in the voltage at the substation. This is not the case for the MultiLevel Market Model in which distribution and transmission-connected assets can participate in the VCM. The distribution-connected flexibility providers managed to provide enough reactive power to increase the voltage above the 0.96 pu limit. To do that, demand response as a flexibility service was used.

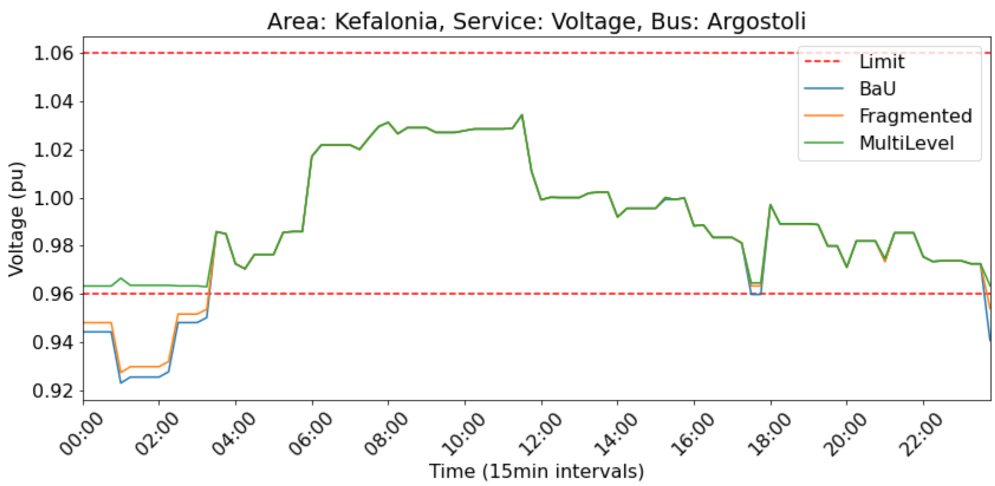

Figure 8. Example of a daily voltage variation at Argostoli substation during August when peak load appears.

5. Conclusions

This paper examines the technical and regulatory aspects linked with Transmission System Operator (TSO) and Distribution System Operator (DSO) cooperation in overcoming local transmission system problems concerning Voltage regulation. Two market-based coordination schemes, the Fragmented and the MultiLevel Market Models as described in the Horizon 2020 CoordiNet project, for voltage regulation, are demonstrated and analysed. The proposed coordination schemes' key goal is to increase the active participation of flexible service providers in providing ancillary services to the system operator through the development of a market at the local level. The market platform developed converts the steady-state reactive power products submitted by the FSPs to voltage service provided to the specific transmission system bus. The optimisation algorithm produces the merit order based on the service provided. Under the first coordination scheme, the Fragmented Market Model, the TSO can receive voltage support from transmission-connected flexibility assets such as nearby large wind or solar farms. Under the second scheme, the Multilevel Market Model, the TSO can receive voltage support from transmission and distribution-connected flexibility assets. At the distribution level, flexibility can be provided by aggregators connected under a specific HV/MV Substation. The merit order between the different flexibility service providers is decided based on the service provided, i.e., the regulation of voltage they provide, and not strictly by the price of the offer they submit, in euros per reactive power change.

The above-mentioned coordination schemes and the market models for voltage regulation were tested at Kefalonia, which was the demonstration site for the Horizon 2020 CoordiNet project. The particular characteristics of Kefalonia island were ideal to test both overvoltages and undervoltages. Results show that in the BaU scenario, the voltage can take values near the actual limits. Even though currently there are no major violations recorded in regulating the voltage with passive components, in a 100% renewables scenario, however, the above-mentioned cases can take even more extreme values and can lead to actual problems and voltage violations. In our demonstrations, the limits for voltage regulation were set to be stricter to show the operation of the VCM with local and nearby flexibility providers. It is shown that for overvoltages, flexibility service providers and especially transmission-connected wind farms, can effectively regulate the increased voltage. This is because overvoltages appear when RES are producing at their maximum, which means that wind farms can provide significant reactive power to the VCM. Therefore, in both Fragmented and MultiLevel Market Models overvoltages were effectively mitigated. However, this is not the case when undervoltages appear. Undervoltages appear during a low RES/peak net load scenario and, therefore, RES cannot be used as flexibility service providers. To mitigate undervoltage problems, demand response from distribution-connected flexibility service providers was used. Energy storage technologies connected to both the transmission and distribution system will play an important role in providing reactive power for voltage regulation. To conclude, TSO/DSO coordination and ancillary services energy markets can create financially viable solutions for TSO to leverage flexibility from distribution grids, defer grid investment and provide service-based solutions to address issues that may arise due to the energy transition to a cleaner future.

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