Reactive Power Management: Comparison of Expert-based and Optimization-based Approaches for Dispatcher Training

Abhimanyu Kaushal[1], Artur Mirowski[2], Mateusz Skwarski[3], Jacek Wasilewski[4], Hakan Ergun[5], and Dirk Van Hertem[5]

[1]KU Leuven Science Engineering and Technology Group
[2]Orsted Polska Of Services
[3]PSE Innowacje
[4]PSE SA Warsaw
[5]KU Leuven

May 3, 2023

Abstract

Reactive power management (RPM) in electric power systems is usually based on a rule-based control derived from the transmission system operator's experience. This approach faces challenges as the number of decisions and the complexity of the system operation is increasing. With the increasing generation from renewables and the evolution of electricity markets, the available resources must be optimally utilized. In this paper, a comparison is made between the optimization-based approach (OBA) and the experience-based expert approach (EBA) for RPM. The OBA is based on security-constrained optimization with minimum redispatch cost as the objective function for different contingencies. In contrast, the EBA's actions are based on the system operator's experience. Comparison is made in terms of the generator redispatch cost, active and reactive power redispatch volume, nodal voltages, and the number of actions to ensure secure operation. The analysis using a reduced model of the target system shows that OBA is more beneficial than EBA, with up to 22% and 42% reduction in redispatch cost and volume, respectively. Moreover, the control decisions from both approaches are seen to be similar. This study aims to show the usefulness of the OBA and motivate TSOs to move towards optimization-based reactive power management

IET Research Journals

Journals
The Institution of Engineering and Technology

Reactive Power Management: Comparison of Expert-based and Optimization-based Approaches for Dispatcher Training

ISSN 1751-8644
doi: 0000000000
www.ietdl.org

Abhimanyu Kaushal[1,2*], *Artur Mirowski*[3], *Mateusz Skwarski*[4], *Jacek Wasilewski*[5], *Hakan Ergun*[1,2], *Dirk Van Hertem*[1,2]

[1] *Research Group ELECTA, Department of Electrical Engineering (ESAT), KU Leuven, Leuven, 3001, Belgium*
[2] *EnergyVille, Genk, 3600, Belgium*
[3] *Orsted Polska Of Services, Poland*
[4] *PSE Innowacje, Poland*
[5] *PSE S.A. Poland*
* *E-mail: abhimanyu.kaushal@kuleuven.be*

Abstract: Reactive power management (RPM) in electric power systems is usually based on a rule-based control derived from the transmission system operator's experience. This approach faces challenges as the number of decisions and the complexity of the system operation is increasing. With the increasing generation from renewables and the evolution of electricity markets, the available resources must be optimally utilized. In this paper, a comparison is made between the optimization-based approach (OBA) and the experience-based expert approach (EBA) for RPM. The OBA is based on security-constrained optimization with minimum redispatch cost as the objective function for different contingencies. In contrast, the EBA's actions are based on the system operator's experience. Comparison is made in terms of the generator redispatch cost, active and reactive power redispatch volume, nodal voltages, and the number of actions to ensure secure operation. The analysis using a reduced model of the target system shows that OBA is more beneficial than EBA, with up to 22% and 42% reduction in redispatch cost and volume, respectively. Moreover, the control decisions from both approaches are seen to be similar. This study aims to show the usefulness of the OBA and motivate TSOs to move towards optimization-based reactive power management.

1 Introduction

In liberalized electricity markets, a transmission system operator (TSO) procures energy from other market participants. In addition to energy, a TSO also requires ancillary services (AS) for secure and reliable power system operation [1]. These AS help the TSO to maintain the power system characteristics such as nodal voltage, system frequency and system restoration capability [2]. Freedom in energy procurement from the electricity market has increased power exchanges among different control areas. A direct consequence of these changes is the power system being operated closer to its limits [3]. Power injection from renewable energy sources (RES) at distribution and sub-transmission levels in the grid impacts the voltage and system stability [4–7]. The voltage is a local quantity and depends upon the nodal reactive power balance. A set of control measures/actions which helps in maintaining the reactive power level/voltage at each system node are known as reactive power management (RPM) or Var planning or voltage control ancillary services (VCAS) [8].

Reactive power support also helps maintain the transmission line power flow limits in addition to the nodal voltage limits. The reactive power needs to be procured at various locations in the system, and the reactive power requirement depends upon the expected demand and the power flow conditions [9]. The criticality of voltage control is complicated by the availability of reactive power control resources at different locations in the system. Due to the reduction in operating time of the conventional power plants, the sources for reactive power in the system are decreasing. Further, owing to the increasing distance between generation locations and the load centers and changing local voltage patterns (on account of distributed RES connections), the demand for reactive power in the grid is increasing [10].

A TSO is entrusted with ensuring that the voltage remains within limits in its control area. For any deviation in nodal voltage, the control actions such as tap change of power transformer, switching of capacitors/reactors, control of high voltage direct current (HVDC) systems and change in reactive power output of synchronous generators etc., are used for regulating the reactive power in the system [8]. Local and centralized control are the two hierarchical levels for reactive power control followed in most of the European countries (except for France and Italy, where primary, secondary and tertiary level controls are implemented) [11]. The details about the hierarchical reactive power/voltage control in different countries are presented in [12].

The authors in [13, 14] have presented a security-constrained optimal power flow (SCOPF) model for Var support in power systems. Application of SCOPF for optimal Var sources planning for large power systems is presented in [15]. In [16, 17] application of SCOPF to high voltage system of the National Grid Company for optimal installation of reactive power resources and analysis of Var costs has been presented. The authors in [18] have presented a SCOPF model for post-contingency curative rescheduling. In [19], the authors have presented an approach to couple SCOPF-based optimization and dynamic simulation for voltage control. A SCOPF-based model for reducing the number of control actions for real-time voltage control has been presented in [20].

In [21], the authors have presented a review of various objective functions, constraints and algorithms for the reactive power planning. The authors in [22] have presented a survey on the reactive power ancillary service markets. A review of the trends for reactive power procurement in different countries has been presented in [23]. A survey carried out by European Network of Transmission System Operators for Electricity (ENTSO-E) on ancillary services procurement and balancing market design for the year 2020 [24] provides insights into various aspects of VCAS, such as methodology, procurement and payment schemes, details of participants, type of control etc., followed by different TSOs in

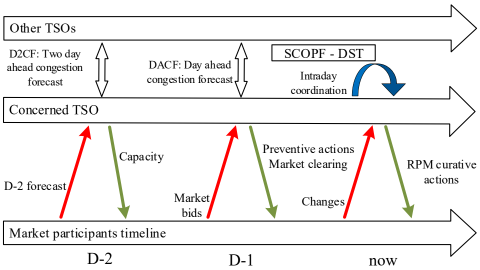


Fig. 1: Stakeholder interaction in energy market

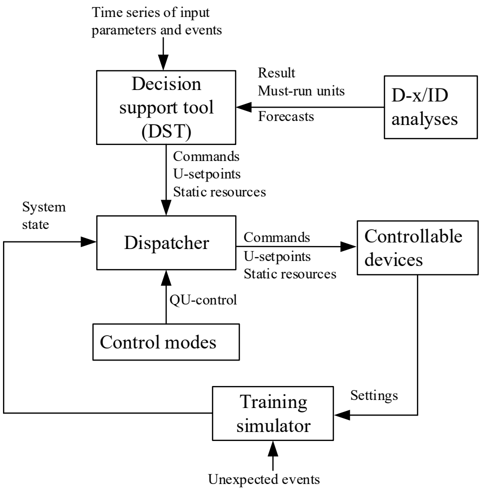


Fig. 2: Decision support tool overview

Europe. The survey highlights that different TSOs in the ENTSO-E area follow different approaches for RPM. While RPM based on optimization is implemented in many studies, many TSOs still do not use this approach.

In Poland, voltage control is a mandatory service to be provided by synchronous generators. As a part of the EU-SysFlex project [25], a decision support tool (DST) has been developed for the cross-border coordination and the dispatch scheduling. The DST aims to ensure efficient and coordinated use of system flexibilities with integration of a large share of RES [26]. In this paper, the dispatch scheduling module, which uses an optimization-based approach for voltage control and RPM, is presented (referred to as SCOPF-DST) [27]. The SCOPF-DST has been developed to help the TSO with near-to-real-time RPM and voltage control decisions/actions as seen in Fig. 1. The steady-state SCOPF model provides the TSO with curative actions to be performed for each of the considered contingencies.

A dispatcher training simulator (which mimics the control room) has been developed by Polskie Sieci Elektroenergetyczne S.A. (PSE) for the EU-SysFlex project to train the system operators for different operating scenarios so that they can improve their decision making in real-time [26]. The interface for interaction of SCOPF-DST with the dispatcher training simulator is as shown in Fig. 2. Different operational scenarios, including a list of units available for curative actions used for the dispatcher training simulator, are used as input to the SCOPF-DST, and the output is presented as a series of near to real-time actions. The SCOPF-DST has not been designed for direct interfacing with the control room in mind. Instead, it is intended to provide dispatchers with pre-calculated control options when using the dispatcher training simulator to augment their real-time decision-making process. The SCOPF-DST provides optimal voltage settings to the dispatcher in the training environment for a predetermined time series of exogenous conditions and uncertainties. Different sources of reactive power are considered while calculating the optimal voltage setpoints.

A number of optimization-based RPM techniques have been presented by several authors in literature, however, these are not being used by the TSOs for decision-making. In this paper, the authors are trying to bridge the gap between available optimization models and system operators' methods. The contribution of this paper is a comparison of the optimization-based approach (OBA) using the SCOPF-DST decisions, and the expert approach (EBA) based decisions for different real-time operational scenarios. It is expected that the optimization-based decisions can outperform the operator's experience-based decisions if they can account for all the decisions and sufficient modelling details. It is also expected that the optimization-based algorithms will help to reduce the overall system operation cost, and all the resources could be used more effectively. The comparison would also help show the similarities and differences in the decisions from both approaches. The similarities in the decisions taken would be helpful to build confidence in the system operators for OBA or to develop new operationalities.

The details of the EBA based RPM approach followed by PSE in Poland are presented in section 2. Section 3 details the mathematical modelling of the SCOPF-DST along with the objective function and various constraints for the model. The details of the case study are presented in section 4. Section 5 presents the results from the analysis and the discussion on these results. The conclusions are presented in section 6.

2 Expert approach

Human experience and learning from historical events are followed as the current practice for voltage control and RPM by PSE [27]. This approach is used close to real-time for using static reactive power resources and setting voltage setpoints. To ensure secure power system operation, a list of must-run units and units available for curative actions in case of contingencies is provided to the dispatchers based on the seasonal, day-ahead and intraday analysis. In different regions, the reactive power resources' settings are controlled by the regional control centers. The reactive power output of the generators is altered based on a voltage setpoint at the terminal busbar of the generator using control modules in the energy management system. Similarly, the tap settings of the transformers are controlled based on a voltage setpoint at the high-voltage side, or the low-voltage side, or the requested reactive power flow through the transformer.

To account for the inaccuracies in the models used for ahead of real-time analysis, some additional actions such as static reactive power resources' switching might be needed. No additional analyses are carried out close to real-time by the dispatchers to determine the most appropriate actions. The voltage setpoints for the generators and transformers, controllable reactive power sources, or the reactive power flow through the transformers are the decision variables in close-to-real-time system operation. These decisions by the system operator are based on the following objectives with different priorities as per the following and are as shown in Fig. 3.

- The individual system nodal voltages U_i should remain within the specified permissible range ($\underline{U_i}$ and $\overline{U_i}$) for the system state.
- If the above objective is fulfilled then the system operator tries to operate the power system with minimum losses. This is done by ensuring the availability of reactive power resources at different system nodes.
- If it is not possible to keep the nodal voltages within the permissible range, the system operator tries to keep the nodal voltages at the problematic nodes close to the voltage limits (deviation of $\pm\delta$ only for some severe and rare system scenarios/contingencies).
- The system operator ensures that enough reactive power reserves from synchronous generators and adequate regulation of the transformer ratio (tap changer control) is available.

The expert decisions are based on the load flow calculations, voltage stability assessment (PV and QV curves) and N-1 contingency analysis. In addition to this, the reactive power management also takes the historical events and their convergence (topology and measurement) into account [28]. It is ensured while incorporating relaxation of $\pm\delta$ in the nodal voltage bounds that the overall power quality parameters meet the system operator's operational criterion.

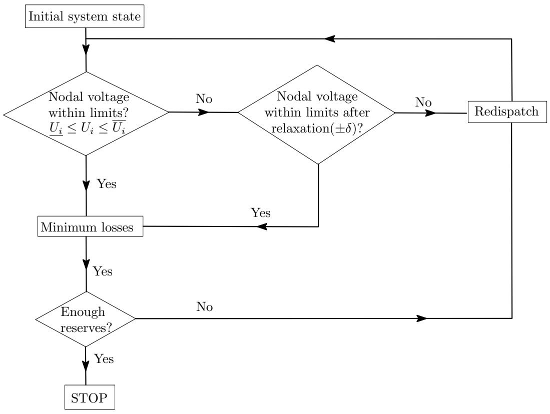


Fig. 3: Methodology for expert approach

3 Optimization-based approach

For the optimization-based a simplified and well-known SCOPF model has been used to ensure its scalability and industrial application. The OBA uses a SCOPF model, which determines the necessary control actions to ensure that the system voltages remain within limits for all considered contingencies [21]. The cost of these control actions, referred to as redispatch cost, is finally recovered from the grid users. OBA focuses on social welfare maximization, and thus, it aims to minimize the sum of the generator redispatch costs and demand curtailment costs w.r.t. the market outcome. Let $\mathcal{I}$, $\mathcal{G}$, $\mathcal{L}$, $\mathcal{B}$ and $\mathcal{O}$ denote the system nodes, generators, loads, branches and set of contingencies respectively. Also, $\mathcal{T}^{ac}$, $\mathcal{T}^{gen}$ and $\mathcal{T}^{load}$ denotes the AC system topology, generator and load connectivity, respectively. The objective function can be mathematically represented as the following:

$$min\left(\sum_{g} (C^{p}_{g,o} \cdot |\Delta P_{g,o}| + C^{q}_{g,o} \cdot |\Delta Q_{g,o}|) \right) \tag{1}$$

where $\Delta P_{g,o}$ and $\Delta Q_{g,o}$ are the changes in active and reactive power setpoints for the generators. $C^{p}_{g,o}$ and $C^{q}_{g,o}$ represent the cost coefficients associated with changes in active and reactive power setpoints for the generators. $\Delta P_{g,o}$ and $\Delta Q_{g,o}$ in (1) are the decision variables associated with the optimization problem and calculated as per (2) - (3).

$$\Delta P_{g,o} = P_{g,o} - P^{ref}_{g} \;\; \forall \;\; g \in \mathcal{G}, \;\; \forall \;\; o \in \mathcal{O} \tag{2}$$

$$\Delta Q_{g,o} = Q_{g,o} - Q^{ref}_{g} \;\; \forall \;\; g \in \mathcal{G}, \;\; \forall \;\; o \in \mathcal{O} \tag{3}$$

The reference stage generator and load active and reactive power setpoints are based on the market clearing outcome (denoted as superscript ref).

For the optimization problem, the power system is represented using a non-linear ac formulation in polar coordinates based on [29] and as detailed in [30]. The generator active and reactive power outputs are constrained by the operational limits as per [31, 32] and given as:

$$\left. \begin{array}{l} \underline{P_g} \leq P_{g,o} \leq \overline{P_g} \\ \underline{Q_g} \leq Q_{g,o} \leq \overline{Q_g} \end{array} \right\} \forall \, g \in \mathcal{G}, \;\; \forall \;\; o \in \mathcal{O} \tag{4}$$

here $\underline{P_g}$, $\overline{P_g}$ are the active power limits and $\underline{Q_g}$, $\overline{Q_g}$ are the reactive power limits for the generators. The following are used to relax the absolute values of the generator active and reactive power redispatch for the contingencies and gives the minimum and maximum limits for changes in setpoints:

$$\left. \begin{array}{l} \underline{P_g} - \overline{P_g} \leq \Delta P_{g,o} \leq \overline{P_g} - \underline{P_g} \\ \underline{Q_g} - \overline{Q_g} \leq \Delta Q_{g,o} \leq \overline{Q_g} - \underline{Q_g} \end{array} \right\} \forall \, g \in \mathcal{G}, \;\; \forall \;\; o \in \mathcal{O} \tag{5}$$

The status of the contingent generator and/or transmission line is set to zero, and the equations for these system elements are not added to the optimization problem.

The bus voltages are maintained within the operational limits as per:

$$\underline{U_i} \leq U_{i,o} \leq \overline{U_i} \;\; \forall \;\; i \in \;\; \mathcal{I}, \;\; \forall \;\; o \in \mathcal{O} \tag{6}$$

The phase angle difference of AC buses is constrained within the limits $\underline{\theta_{ij}}$ and $\overline{\theta_{ij}}$ by the following constraint:

$$\underline{\theta_{ij}} \leq \theta_{ij,o} \leq \overline{\theta_{ij}} \;\; \forall \;\; i,j \in \mathcal{I}, \;\; \forall \;\; o \in \mathcal{O} \tag{7}$$

For the transmission line model, π representation of the AC branches as per [30] has been used. Ohm's law and Kirchhoff's Current Law (KCL) have been used for calculating the power flow on branch b in direction $i \rightarrow j$ and is given as:

$$P_{bij,o} = (g + g_{fr}) \cdot |U_{i,o}|^2 - (g - b) \cdot |U_{i,o}| \cdot |U_{j,o}| \cdot \cos\theta_{ij,o} - (g + b) \cdot |U_{i,o}| \cdot |U_{j,o}| \cdot \sin\theta_{ij,o} \;\; \forall \;\; bij \in \mathcal{T}^{ac}, \;\; \forall \;\; o \in \mathcal{O} \tag{8}$$

$$Q_{bij,o} = -(b + b_{fr}) \cdot |U_{i,o}|^2 - (g + b) \cdot |U_{i,o}| \cdot |U_{j,o}| \cdot \cos\theta_{ij,o} - (g - b) \cdot |U_{i,o}| \cdot |U_{j,o}| \cdot \sin\theta_{ij,o} \;\; \forall \;\; bij \in \mathcal{T}^{ac}, \;\; \forall \;\; o \in \mathcal{O} \tag{9}$$

and in direction $j \rightarrow i$ as:

$$P_{bji,o} = (g + g_{fr}) \cdot |U_{j,o}|^2 - (g - b) \cdot |U_{j,o}| \cdot |U_{i,o}| \cdot \cos\theta_{ji,o} - (g + b) \cdot |U_{j,o}| \cdot |U_{i,o}| \cdot \sin\theta_{ji,o} \;\; \forall \;\; bji \in \mathcal{T}^{ac}, \;\; \forall \;\; o \in \mathcal{O} \tag{10}$$

$$Q_{bji,o} = -(b + b_{fr}) \cdot |U_{j,o}|^2 - (g + b) \cdot |U_{j,o}| \cdot |U_{i,o}| \cdot \cos\theta_{ji,o} - (g - b) \cdot |U_{j,o}| \cdot |U_{i,o}| \cdot \sin\theta_{ji,o} \;\; \forall \;\; bji \in \mathcal{T}^{ac}, \;\; \forall \;\; o \in \mathcal{O} \tag{11}$$

g, g_{fr}, b and b_{fr} in these equations are the branch π section conductance and susceptance parameters. Subscript fr in g_{fr} and b_{fr} refers to the from end of the transmission line.

The power flows are limited by the branch operational limits as follows:

$$(P_{bij,o})^2 + (Q_{bij,o})^2 \leq (S^{rated}_{b})^2 \, \forall \, b \in \;\; \mathcal{B}, \, \forall \, o \in \mathcal{O} \tag{12}$$

$$(P_{bji,o})^2 + (Q_{bji,o})^2 \leq (S^{rated}_{b})^2 \, \forall \, b \in \;\; \mathcal{B}, \, \forall \, o \in \mathcal{O} \tag{13}$$

The nodal power balance equations are defined as follows:

$$\sum_{bij \epsilon \mathcal{T}^{ac}} P_{bij,o} = \sum_{gi \epsilon \mathcal{T}^{gen}} P_{gi,o} - \sum_{li \epsilon \mathcal{T}^{load}} P_{li,o} - g^{shunt}_{i} \cdot U^2_{i,o} \;\; \forall \;\; i \in \mathcal{I}, \;\; \forall \;\; o \in \mathcal{O} \tag{14}$$

$$\sum_{bij \epsilon \mathcal{T}^{ac}} Q_{bij,o} = \sum_{gi \epsilon \mathcal{T}^{gen}} Q_{gi,o} - \sum_{li \epsilon \mathcal{T}^{load}} Q_{li,o} + b^{shunt}_{i} \cdot U^2_{i,o} \;\; \forall \;\; i \in \mathcal{I}, \;\; \forall \;\; o \in \mathcal{O} \tag{15}$$

Fig. 4 shows an overview of the OBA approach. Initially, the data depicting the initial system state (as provided by the system

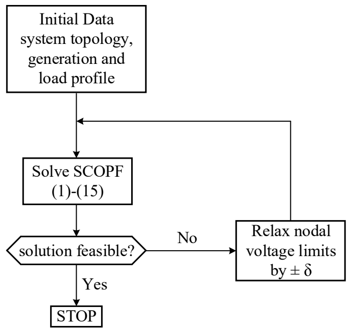


Fig. 4: Overview of optimization-based reactive power management

operator) is used to solve the SCOPF-based optimization problem. If the solution is not feasible, nodal voltage limits are relaxed by $\pm\delta$, and the SCOPF-based optimization problem is solved again. As the OBA uses a full non-linear ac formulation, it might lead to sub-optimal results. Several techniques/methods have been proposed in the literature to guarantee the optimality of optimization-based solutions. However, the main focus of this paper is to compare the decisions from OBA and EBA; thus, this work does not look into the optimality aspect of the optimization-based approach solutions.

4 Case study

4.1 Test System and assumptions

RPM analysis has been carried out on a system representative of the Polish transmission system as used in [28]. PSE has provided the data for analysis as a time series of input parameters and events. This data consists of the anticipated grid states for the Polish transmission system (generation, load and topology) and the unexpected events (system contingencies) and is updated every 15 minutes.

The system consists of 339 extra-high voltage (EHV) nodes (220kV and above) and 383 high-voltage transmission lines. The generation mix for the system consists of synchronous generators, wind farms, aggregated PV and pumped hydro generators. There are 18 interconnections with other countries in the system under consideration. These interconnections are considered as equivalent generators operating in PQ mode. To avoid the complexities, only generator redispatch and the use of shunt/capacitors have been considered in the analysis.

For the analysis, the tripping of the biggest generator (886 MW) is considered as the reference incident. The dispatch costs for various generators are considered based on their fuel types. The generator redisptach price for RPM is not publically available, hence the generator active power redispatch price is considered to be the same as that for frequency replacement reserve price for Poland. Fig. 5 shows the variation of replacement reserves price with respect to day-ahead market clearing price for October-December 2020 for Poland. The replacement reserve and day-ahead market clearing prices are considered based on the data available on the ENTSO-E transparency platform [33, 34]. It was seen that the mean value of the ratio varies from 4.5 to 4.8, and hence for our analysis, it was assumed that the generator active power redispatch cost coefficient for the contingency is five times that of the dispatch cost coefficient. The reactive power redispatch cost coefficient is considered as 1/5 that of the active power redispatch cost coefficient [35].

In this paper, the RPM analysis has been carried out for three different timestamps. The system parameters, such as the total number of generators, the total number of nodes and the total load in the system for the different timestamps, are shown in Table 1. These three timestamps show the different power flow scenarios for the considered system. The considered test system is already constrained owing to the increased power flows from non-synchronous RES [28]. For the timestamp TS1, the system is undergoing maintenance. During the initial operation for the timestamp TS2, the generation from RES is the highest. Also, for this

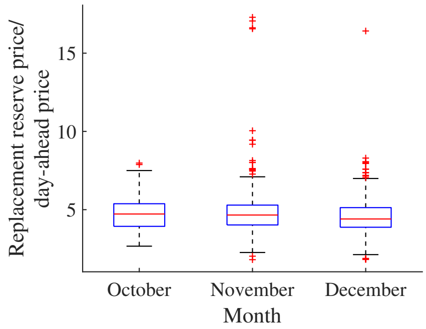


Fig. 5: Ratio of replacement reserve price and day-ahead price for Poland

Table 1 System parameters for different timestamps

Timestamp $\rightarrow$ System Parameter $\downarrow$	TS1	TS2	TS3
Generator number	102	103	102
Number of nodes	450	451	450
Total Load (GW)	30.43	30.67	30.58
Total Load (GVAr)	7.24	7.23	7.26
RES (%)	63.8	68.9	64.3
P (MW) for contingent generator	886	400	1000
Q (MVAr) for contingent generator	-900	300	1064

timestamp the reactive power resources are limited in the system. This is done in order to investigate the system's behaviour in extreme cases. For the timestamp TS3, an average non-synchronous RES generation scenario is considered.

4.2 Framework for optimization model

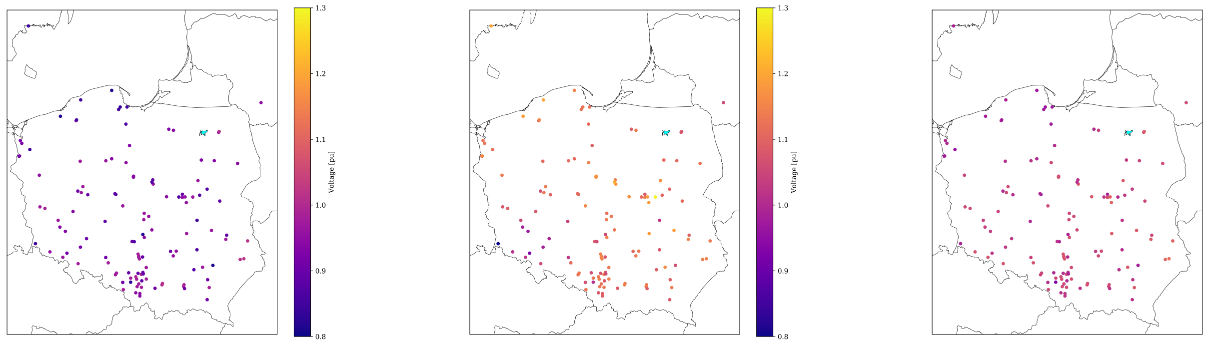
The optimization-based SCOPF model is developed in the Julia programming language [36] using the JuMP package for optimization [37] and uses the features of the PowerModels.jl [30] and PowerModelsReliability.jl [38] packages. The simulations for OBA were performed on a PC clocked at 2.6-GHz with 32-GB RAM using the IPOPT solver (version 0.5.4) [39], and the computation time was in the order of 10-20s for the considered test system and contingency for each timestamp.

5 Results

The objective of RPM is to ensure that the nodal voltage limits are adhered to in all situations. This is achieved by redispatching the available reactive power resources in case of a contingency. As mentioned earlier, for the timestamp TS1, the system is undergoing maintenance, and hence the voltage (U_i) is out of limits at some system nodes as detailed in Table 2. For the timestamp TS2, the voltage at several system nodes violates the upper voltage limit of 1.1 pu as shown in Table 2 owing to a lot of generation from RES [28]. For the timestamp TS3, there is violation in the upper voltage limits at some system nodes.

For the considered system, in the event of the reference contingency, if no remedial control action is taken, the number of system nodes with voltage violation increases to 82 for timestamp TS1 as presented in Table 2. For timestamps TS2 and TS3, the total number of voltage violations decreases for the reference contingency when no remedial action is taken; however, there is still voltage limit violation at 236 and 11 system nodes, respectively as shown in Table 2. Fig. 6 shows the spacial voltage profile of the system nodes for the reference contingency without any remedial control action.

In the next step of the analysis, remedial actions were applied for each of the timestamps based on EBA and OBA. It was seen that with both approaches, it was possible to operate the system



(a) TS1 (b) TS2 (c) TS3

Fig. 6: Nodal voltages for reference contingency without generator redispatch

Table 2 Nodal voltage violations without RPM

Scenario ↓	Timestamp ↓	Number of nodes	
		$U_i < 0.9$ p.u.	$U_i > 1.1$ p.u.
Initial operation	TS1	25	14
	TS2	6	302
	TS3	0	19
Generator contingency	TS1	82	0
	TS2	6	230
	TS3	0	11

Table 3 System nodal voltages

Timestamp	TS1		TS2		TS3	
Parameter → Approach ↓	U_{avg}	U_{sd}	U_{avg}	U_{sd}	U_{avg}	U_{sd}
Initial state	1.02	0.09	1.23	0.12	1.05	0.04
No action	0.93	0.04	1.11	0.09	1.04	0.04
OBA	1.00	0.02	0.92	0.03	1.01	0.02
EBA	1.00	0.04	0.96	0.04	1.05	0.04

within the permissible limits (slightly relaxed limits for TS2) using the generator redispatch after the occurrence of the contingency. The approaches have been compared in terms of the voltage profile at system nodes, redispatch volume, redispatch cost and the number of actions taken to mitigate the voltage violations as presented in the following sections.

5.1 *Nodal voltage*

The voltage at the system nodes represents the reactive power balance in the system. As mentioned earlier, the considered system is already constrained with nodal voltage violations in the initial operation stage as well as on occurrence of the reference contingency without any remedial control actions. Changing the active and reactive power setpoints of the available resources is a possible countermeasure to avoid voltage issues or a voltage collapse in the extreme case. Fig. 7 shows a comparison of the system nodal voltages for both approaches, the initial system state and for no remedial action for all the timestamps for the considered contingency. It can be observed from the figure that there are a number of violations in the nodal voltage limits in the initial system state as highlighted in Table 2. The nodal voltages with no remedial actions are obtained by the power flow analysis of the system with generator contingency. In this case, the additional power (required due to generator contingency) is compensated by the distributed slack generators, and thus no load-shedding is required.

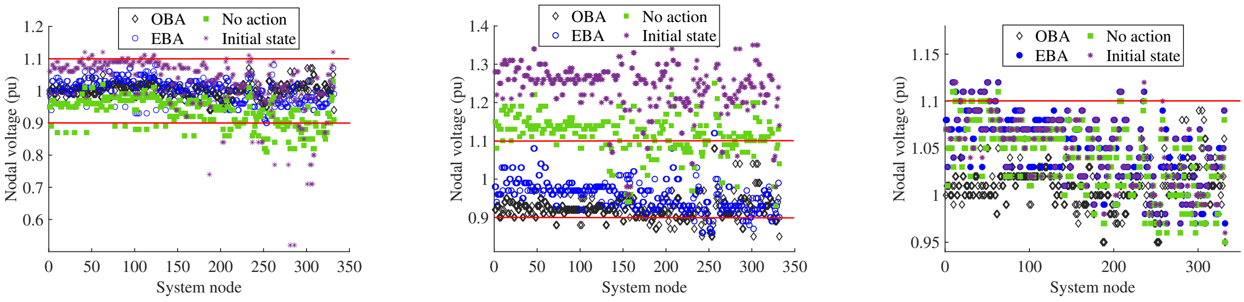
The Fig. 7 also shows that the nodal voltage profile has improved for OBA and EBA as compared to the nodal voltage profile when no redispatch actions were considered. The figure shows that with optimization of the system resources with OBA, for time stamps TS1 and TS3, the bus voltages could be maintained within operational limits of $0.9 - 1.1$ pu. However, for timestamp TS2 (with high RES generation), it was only possible to maintain the voltages at some nodes within relaxed limits of $0.8 - 1.2$ pu using OBA. When using the EBA, it was seen that the system could be operated with nodal voltages within $0.9 - 1.1$ pu for TS1. However, for TS2 and TS3 the nodal voltages could not be maintained between $0.9 - 1.1$ pu and system operation was only possible with relaxed nodal voltage limits of $0.8 - 1.2$ pu.

It is seen that with both approaches, it was not possible to maintain nodal voltage within $0.9 - 1.1$ pu for TS2, and a solution is only feasible with relaxed nodal voltage bounds. As mentioned earlier, only limited reactive power resources are available in the system for this timestamp. This requirement for relaxing voltage bounds can be interpreted as an indicator for future investments in reactive power resources, but in the near real-time horizon, such nodes need to be managed with relaxed constraints.

The average (U_{avg}) and standard deviation (U_{sd}) in nodal voltages for the initial system state, both the approaches and with no remedial actions, are shown in Table 3. It can be seen that OBA and EBA result in keeping a uniform nodal voltage profile for the system as compared to the initial system state and the case when no remedial actions are taken. It can also be observed that OBA results in a lower U_{sd} and hence results in better system performance than the EBA.

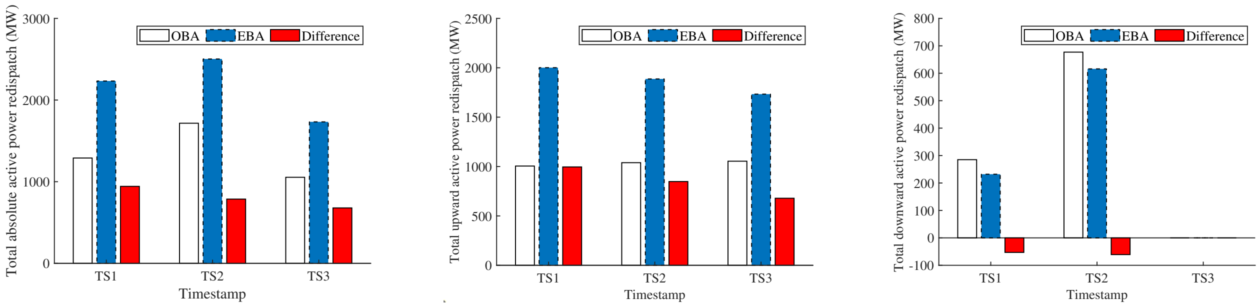
5.2 *Redispatch Volume*

The TSOs have to pay the generation utilities to change their active and reactive power outputs away from the electricity market outcomes. Thus, a minimum amount of redispatch volume to ensure secure power system operation in case of a contingency is desired for economic reasons. For the considered system, the active and reactive power redispatch volumes along with the difference in volumes between the two approaches (EBA-OBA) for the considered generator contingency, are shown in Fig. 8 and Fig. 9, respectively, for all the three timestamps. From Fig. 8, it can be observed that the overall absolute active power redispatch volume is less for all the timestamps for the OBA. Following OBA can result in a reduction of active power redispatch volume by 31% (for TS2) – 42% (for TS1) w.r.t. the active power redispatch volume with EBA. It is also seen that the upward regulation volume required for OBA is less than the EBA for all the timestamps. However, for OBA, more downward regulation volume (negative redispatch) is needed for timestamps TS1 and TS2 as compared to the EBA.



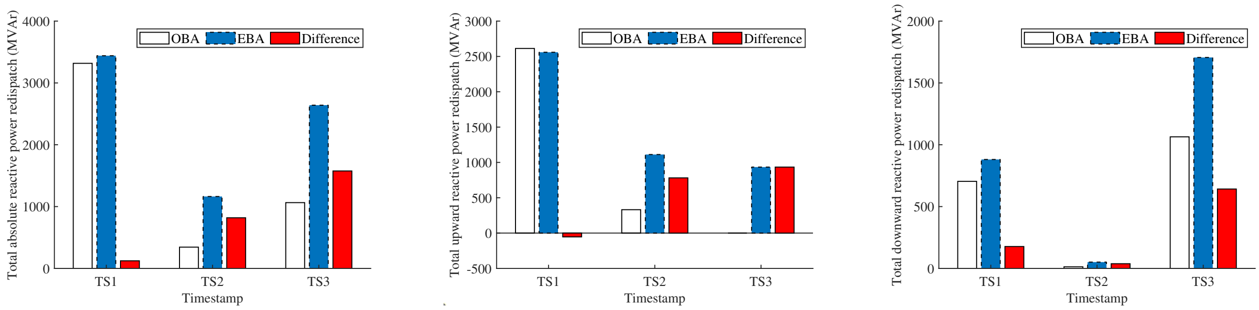
(a) TS-1 (b) TS-2 (c) TS-3

Fig. 7: System voltage profile for reference contingency



(a) Absolute redispatch volume (b) Upward redispatch volume (c) Downward redispatch volume

Fig. 8: Generator active power redispatch volume for reference contingency



(a) Absolute redispatch volume (b) Upward redispatch volume (c) Downward redispatch volume

Fig. 9: Generator reactive power redispatch volume for reference contingency

For the reactive power redispatch volume, it was again seen that the overall redispatch volume is less for OBA as compared to EBA as shown in Fig. 9. Using OBA will lead to the reduction of the reactive power redispatch volume by 4% (for TS1) – 70% (for TS2) w.r.t. the reactive power redispatch volume for EBA. The figure also shows that for both reactive power injection and absorption, the redispatch volume is less for OBA (except for timestamp TS1, where the injection is marginally higher with OBA).

5.3 *Redispatch cost*

A redispatch cost is incurred for generator redispatching actions to maintain system nodal voltages within their limits. As explained in section 3, minimum redispatch cost leads to maximum social welfare. The redispatch cost for the reference contingency has been calculated using (1) for OBA. The total redispatch cost for EBA has been computed based on the generator redispatch volumes and their respective costs. The redispatch costs are presented in Fig. 10 for all the timestamps. It can be observed that the OBA results in a lower redispatch cost for all the timestamps. It was seen that using OBA can result in a reduction in redispatch cost by 12% (for TS2) – 22% (for TS3) w.r.t. the EBA redispatch cost. It can be seen that the redispatch cost with both the approaches is minimum for TS3 as for this timestamp the number of nodal voltage violations was minimum in the initial system operation state. The redispatch costs for TS2 are lower than those for TS1 as for this timestamp the RES contribution was highest and comparatively cheaper generator redispatch could be carried out. The comparison of redispatch cost shows that the OBA will lead to increased social welfare while ensuring secure operational limits.

5.4 *Number of actions*

The number of control actions (number of changes in active and reactive power setpoints) required to secure system operation for a contingency is critical for the system operator. A system operator desires the least number of actions as it takes time to coordinate between different system operators in different control rooms and to effect the changes in the physical system devices. A comparison for the number of actions(with redispatch volume $\geq$ 10 MW/MVAr) for EBA and OBA for RPM has been carried out and is presented in Table 4 for all the timestamps. These actions are required to bring the

Table 4 Number of actions required for RPM

Timestamp → Approach ↓	TS1 OBA	TS1 EBA	TS1 Difference	TS2 OBA	TS2 EBA	TS2 Difference	TS3 OBA	TS3 EBA	TS3 Difference
Active power setpoint changes	50	55	5	48	61	13	43	46	3
Reactive power setpoint changes	38	43	5	10	34	24	6	40	34

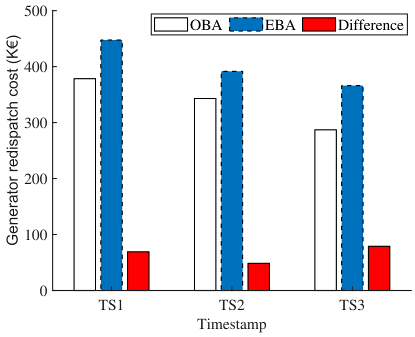


Fig. 10: Generator redispatch cost for reference contingency

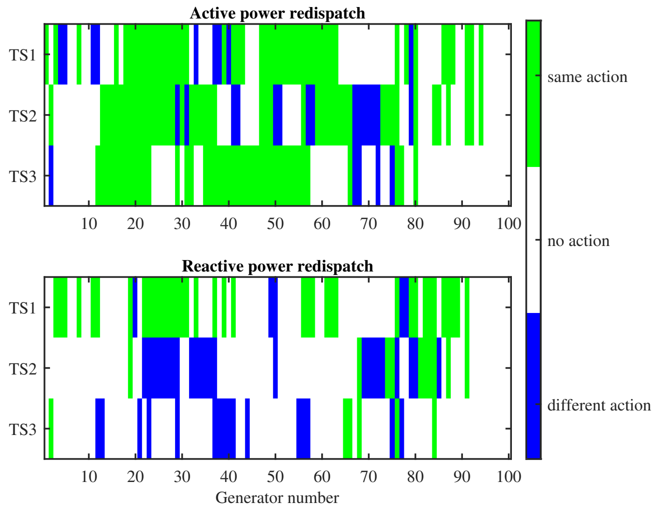


Fig. 11: Similarity in the decisions for both approaches

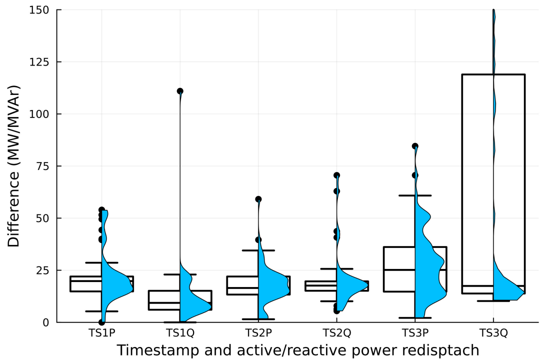


Fig. 12: Difference in generator active/reactive power redispatch setpoints for reference contingency

nodal voltages within the operational limits from the initial system state (with nodal voltage violations) and due to the occurrence of the reference contingency.

It can be observed from this table that with the OBA, the system operator will need to undertake fewer actions as compared to the EBA. Table 4 also shows the difference (EBA-OBA) in the number of actions required for both approaches. The difference in the number of actions is small for TS1; however, there is a significant difference in the number of actions for the other two timestamps. For the OBA, both positive and negative deviation (redispatch) from the initial setpoints is penalized (as shown in (1) for redispatch cost calculation), which restricts the total number of control actions. For EBA, simple heuristics have been used for calculating the decisions. Also, for timestamp TS2 (limited reactive power resources and high-RES scenarios) and TS3 (high-RES scenarios) with the EBA power system operation is only possible after relaxing voltage limits to $0.8 - 1.2$ pu, which in turn gives more flexibility in the generator redispatch. At the same time, negative redispatch is not penalized in the EBA, which increases the number of control actions and a significant difference between the two approaches.

It was seen that using OBA will lead to a reduction of 6% (for TS1) − 43% (TS3) in the required number of actions (difference in the total number of actions/total number of actions for EBA). The reduction in the number of actions with OBA will lead to fewer changes in the setpoints of the controlling devices. At the same time, it will reduce the communication and coordination requirements and thus will reduce the burden on the system operators.

Fig. 11 shows a comparison of the actions taken based on the OBA and the EBA for RPM for the reference contingency for all the timestamps. In this case, an action/decision is considered to be the same if the same generator is redispatched with both approaches, irrespective of the redispatch volume. If any generator has a different redispatch decision between the two approaches, the action is considered to be different. It can be seen in Fig. 11 that most of the decisions for active power redispatch are the same with both approaches. For reactive power redispatch, for timestamp TS1, only a few redispatch actions are different. However, for the remaining two timestamps (TS2 and TS3), a large number of redispatch decisions are different.

Further analysis on the similarity of the redispatch decisions was carried out and is shown in Fig. 12. This figure shows the distribution and density of the difference in generator active and reactive power setpoints with EBA and OBA approaches for all the timestamps and the considered reference contingency. For timestamp TS1 and TS2, the median difference in generator active (with label TS1P and TS2P) and reactive power (with label TS1Q and TS2Q) setpoints for both approaches is less than 25 MW/MVAr. For timestamp TS3, the median difference in the active power setpoint of generators is 25 MW and that for reactive power setpoints is less than 25 MVAr. For active power redispatch decisions for TS3, it is seen that although only a few redispatch decisions are different, there is a considerable difference in the active power redispatch volume. As shown earlier in Fig. 11, many reactive power redispatch decisions were different for TS3 with EBA compared to OBA; this difference in decisions leads to a considerable variation in generator setpoints with EBA and OBA. The same is again highlighted by a significant difference in the generator reactive power setpoints for both the approaches as shown in Fig. 12 (with label TS3Q).

Overall it was observed that for both approaches and for all timestamps, similar generators are redispatched, although the redispatch volume varies.

6 Conclusion

The objective of reactive power management is to minimize the number of nodal voltage limit violations, and that objective has been achieved with both OBA and EBA. A comparison of the SCOPF based OBA, and the EBA has been carried out in this paper detailing the various aspects of RPM. Both approaches have been applied to a system representative of the Polish transmission system. It has been presented that both approaches help in reducing the number of nodal voltage violations while meeting the system operation constraints for a reference contingency. From the comparison of results, the OBA results in a reduction in redispatch cost up to 22% for the reference contingency compared to EBA, which will lead to savings for a TSO and, in turn, increased social welfare. The approaches were also compared in terms of the active and reactive power redispatch volume. It was again seen that the OBA results in lower redispatch volumes. When comparing the number of actions required to mitigate the effects of the reference contingency, it was again seen that the OBA resulted in a smaller number of required actions. The number of actions in OBA can be further reduced by considering the number of actions in the optimization objective function as a multi-objective optimization problem.

One of the major takeaways from the comparison of the two approaches is that for both approaches, most of the redispatched generators are the same, albeit the redispatch volumes are different. This highlights that OBA's decisions are similar to those taken with EBA. The TSOs have been using the EBA for reactive power management for a long time and have confidence in this approach owing to historical reliable system operation. The OBA would improve reactive power management for the futuristic RES-dominant power systems with optimal utilization of available resources. As there is still hesitancy among the system operators to use OBA for RPM, this study can be used as a starting point to instil confidence in OBA for system operation.

7 Acknowledgments

The research leading to this work has been carried out as a part of the EU-SysFlex project (Pan-European system with an efficient coordinated use of flexibilities for the integration of a large share of RES), which received funding from the European Union's Horizon 2020 research and innovation program under grant agreement No. 773505. The work of Abhimanyu Kaushal is supported by the project HVDC Inertia Provision (HVDC Pro), financed by the ENERGIX program of the Research Council of Norway (project number 268053/E20) and the industry partners: Statnett, Equinor, RTE, and ELIA.
The authors will like to thank Da Wang and Reinhilde D'hulst from EnergyVille, Genk and VITO, Mol, Belgium for their valuable contribution to making the dataparser.

8 References

1 Rebours, Y.G., Kirschen, D.S., Trotignon, M., Rossignol, S.: 'A survey of frequency and voltage control ancillary services—part I: Technical features', *IEEE Transactions on Power Systems*, 2007, **22**, (1), pp. 350–357
2 Australian Energy Market Operator: 'Ancillary Services', *Australian Energy Market Operator*, urldate = 11-Oct-2021, Available from: `https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services`
3 Bekaert, D.: 'Reactive power management in planning and operating the transmission grid', *PhD Thesis KU Leuven Faculteit Ingenieurswetenschappen*, 2012,
4 Braun, M.: 'Reactive power supply by distributed generators', *2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century*, 2008, pp. 1–8
5 Vittal, E., O'Malley, M., Keane, A.: 'A steady-state voltage stability analysis of power systems with high penetrations of wind', *IEEE Transactions on Power Systems*, 2010, **25**, (1), pp. 433–442
6 Ullah, N.R., Thiringer, T., Karlsson, D.: 'Voltage and transient stability support by wind farms complying with the e.on netz grid code', *IEEE Transactions on Power Systems*, 2007, **22**, (4), pp. 1647–1656
7 Capitanescu, F.: 'Evaluating reactive power reserves scarcity during the energy transition toward 100% renewable supply', *Electric Power Systems Research*, 2021, **190**, pp. 106672
8 European Commission: 'Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (Text with EEA relevance)', *European Commission*, 2017, Available from: `http://data.europa.eu/eli/reg/2017/1485/oj/eng`
9 Bhattacharya, K., Zhong, J.: 'Reactive power as an ancillary service', *IEEE Transactions on Power Systems*, 2001, **16**, (2), pp. 294–300
10 DENA, German Energy Agency. 'Innovation report: Ancillary services actual achievements and actions needed at present for stable operation of the electric power system up to 2030'. (DENA, 2018). Available from: `https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2019/2018_Innovation_report_ancillary_services.pdf`
11 Kaushal, A., Van.Hertem, D.: 'An overview of ancillary services and HVDC systems in european context', *Energies*, 2019, **12**, (18)
12 Corsi, S. 'Grid Hierarchical Voltage Regulation'. In: Corsi, S., editor. Voltage Control and Protection in Electrical Power Systems: From System Components to Wide-Area Control. Advances in Industrial Control. (London: Springer, 2015. pp. 161–232
13 Degeneff, R.C., Neugebauer, W., Saylor, C.H., Corey, S.L.: 'Security constrained optimization: an added dimension in utility systems optimal power flow', *IEEE Computer Applications in Power*, 1988, **1**, (4), pp. 26–30
14 Granville, S., Pereira, M.V.P., Monticelli, A.: 'An integrated methodology for var sources planning', *IEEE Transactions on Power Systems*, 1988, **3**, (2), pp. 549–557
15 Hsiao, Y.T., Liu, C.C., Chiang, H.D., Chen, Y.L.: 'A new approach for optimal var sources planning in large scale electric power systems', *IEEE Transactions on Power Systems*, 1993, **8**, (3), pp. 988–996
16 Thomas, W.R., Dixon, A.M., Cheng, D.T.Y., Dunnett, R.M., Schaff, G., Thorp, J.D.: 'Optimal reactive planning with security constraints', *Proceedings of Power Industry Computer Applications Conference*, 1995, pp. 79–84
17 Dandachi, N.H., Rawlins, M.J., Alsac, O., Prais, M., Stott, B.: 'OPF for reactive pricing studies on the NGC system', *IEEE Transactions on Power Systems*, 1996, **11**, (1), pp. 226–232
18 Monticelli, A., Pereira, M.V.F., Granville, S.: 'Security-constrained optimal power flow with post-contingency corrective rescheduling', *IEEE Power Engineering Review*, 1987, **PER-7**, (2), pp. 43–44
19 Capitanescu, F., Cutsem, T.V., Wehenkel, L.: 'Coupling optimization and dynamic simulation for preventive-corrective control of voltage instability', *IEEE Transactions on Power Systems*, 2009, **24**, (2), pp. 796–805
20 Soman, S.A., Parthasarathy, K., Thukaram, D.: 'Curtailed number and reduced controller movement optimization algorithms for real time voltage/reactive power control', *IEEE Transactions on Power Systems*, 1994, **9**, (4), pp. 2035–2041
21 Zhang, W., Li, F., Tolbert, L.M.: 'Review of reactive power planning: Objectives, constraints, and algorithms', *IEEE Transactions on Power Systems*, 2007, **22**, (4), pp. 2177–2186
22 Jay, D., Swarup, K.S.: 'A comprehensive survey on reactive power ancillary service markets', *Renewable and Sustainable Energy Reviews*, 2021, **144**, pp. 110967
23 Anaya, K.L., Pollitt, M.G.: 'Reactive power procurement: A review of current trends', *Applied Energy*, 2020, **270**, pp. 114939
24 ENTSO-E. 'Survey on ancillary services procurement, balancing market design for 2020'. (ENTSO-E, 2021). Available from: `https://ee-public-nc-downloads.azureedge.net/strapi-test-assets/strapi-assets/AS_Survey_2020_Results_Updated_42025b2d18.pdf`
25 EU.SysFlex. 'https://eu-sysflex.com/'. (EU-SysFlex, Accessed on 11-Aug-2021)
26 EU-SysFlex. 'WP-4: Simulation of the integration of new system services into System Operator control centres: https://eu-sysflex.com/workpackages/wp4-simulation-of-the-integration-of-new-system-services-into-system-operator-control-centres/'. (EU-SysFlex, 2021)
27 EU-SysFlex. 'Deliverable 4.1 – Developed dispatch & scheduling software for multiple system services provision from new technology'. (EU-SysFlex, 2019)
28 EU-SysFlex. 'Deliverable 4.3 - Report on operator training outcomes with multiple TSO session held in DTS in Warsaw'. (EU-SysFlex, 2021)
29 Carpentier, J.: 'Contribution a l'etude du dispatching economique', *Bulletin de la Societe Francaise des Electriciens*, 1962, **3**, (1), pp. 431–447
30 Coffrin, C., Bent, R., Sundar, K., Ng, Y., Lubin, M.: 'Powermodels.j1: An open-source framework for exploring power flow formulations', *2018 Power Systems Computation Conference (PSCC)*, 2018, pp. 1–8
31 Capitanescu, F.: 'Assessing Reactive Power Reserves With Respect to Operating Constraints and Voltage Stability', *IEEE Transactions on Power Systems*, 2011, **26**, (4), pp. 2224–2234
32 Avramidis, I.I., Capitanescu, F., Karagiannopoulos, S., Vrettos, E.: 'A Novel Approximation of Security-Constrained Optimal Power Flow With Incorporation of Generator Frequency and Voltage Control Response', *IEEE Transactions on Power Systems*, 2021, **36**, (3), pp. 2438–2447
33 ENTSO-E. 'Transparency platform—Price of Activated Balancing Energy: https://transparency.entsoe.eu/balancing/r2/pricesofactivatedbalancingenergy/show'. (ENTSO-E, Accessed on 27-May-2022)
34 ENTSO-E. 'Transparency platform—Day-ahead Prices: https://transparency.entsoe.eu/transmission-domain/r2/dayaheadprices/show'. (ENTSO-E, Accessed on 27-May-2022)
35 Hasanpour, S., Ghazi, R., Javidi, M.H.: 'A new approach for cost allocation and reactive power pricing in a deregulated environment', *Electrical Engineering*, 2009, **91**, (1), pp. 27
36 Bezanson, J., Edelman, A., Karpinski, S., Shah, V.B.: 'Julia: A fresh approach to numerical computing', *SIAM Review*, 2017, **59**, (1), pp. 65–98
37 Dunning, I., Huchette, J., Lubin, M.: 'JuMP: A Modeling Language for Mathematical Optimization', *SIAM Review*, 2017, **59**, (2), pp. 295–320
38 Geth, F.: 'PowerModelsReliability', *GitHub repository*, Accessed on 18-Dec-2020, Available from: `https://github.com/frederikgeth/PowerModelsReliability.jl`
39 Wächter, A., Biegler, L.T.: 'On the implementation of an interior-point filter line-search algorithm for large-scale nonlinear programming', *Mathematical Programming*, 2006, **106**, pp. 25–57