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Evaluating reactive power reserves scarcity during the energy transition toward 100% renewable supply☆

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A R T I C L E I N F O

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A B S T R A C T

The energy transition toward renewable-dominated electricity supply, which many countries committed to achieve in the next decades, will pose major challenges to power systems reliable operation. A significant anticipated challenge, yet not tackled quantitatively by research works, is that, if countermeasures are not planned, the transmission grid will likely face in the years to come extreme situations of lack and/or excess of reactive power. This paper first raises awareness on the key issue of reactive power reserves scarcity as one moves toward renewable-dominated electricity supply and brings quantitative evidence underpinning this issue. Then, the paper elaborates a crude first version of a methodology to predict when such issue may start to occur. The core of the methodology includes a tailored AC security-constrained optimal power flow (SCOPF) problem which evaluates the reactive power reserves scarcity. The usefulness of the proposed methodology is illustrated on two systems of 5 and 60 buses, respectively, considering $N-1$ contingencies.

1. Introduction

1.1. Context and motivation

The energy transition toward more sustainable (renewable-dominated) electricity supply,[1] which many countries committed to achieve in the next decades [1], will lead to progressively displace large fossil fuelled conventional power plants with a myriad of renewable energy sources (RES) scattered primarily in MV/LV networks. This transition will pose various major challenges to power systems reliable operation [2]. Most recent researches focus primarily on active power related issues in low-inertia power systems such as: control of power balance and rate of change of frequency [4].

This paper focuses on another significant challenge for which, to the author' knowledge, quantitative research works do not exist yet. This challenge is that, in the most likely energy transition scenario and if countermeasures are not planned, the transmission grid will likely face in the years to come extreme situations of dramatic lack and/or excess of reactive power and consequently under-voltages (or even voltage instability) and over-voltages, respectively. If the lack of reactive power can be easily imagined, the excess could arise for example in a scenario with light load and massive MV/LV RES production and hence small magnitude power flows through the transmission system.

These issues are to be expected basically because RES can not ensure the same high quality of reactive power ancillary services as conventional power plants due to the following reasons. While conventional power plants were properly planned and installed at appropriate locations to face quite easily to predict operation conditions, high RES penetration will likely lead to unplanned and hard to predict demand and generation patterns which may stress the transmission grid in areas where the reactive power support is scarce. In other words, it is envisioned that reactive power reserves will become significantly variable and even volatile in space and time. In addition:

- some RES (e.g. PV panels in LV grids) are by default (i.e. according to the grid code) operating at unitary power factor and is uneasy or very costly to change this;
- those RES that can control their reactive power output could be utilized in the management of active distribution networks by the distribution system operators or part of their physical RPR might be ineffective due to congestion or high losses in distribution grids;
- as reactive power has a pronounced local impact, it is less effective for remote transmission system support due to several stages of transformers (from LV to MV and HV);
- RES are more sensitive than conventional generators to unusual operation conditions and may disconnect depriving the system of

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[1] Targeting ideally 100% renewable electricity supply [2,3].

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Nomenclature

Sets

$\mathcal{N}$	set of buses
$\mathcal{N}_i$	set of buses linked with bus i
$\mathcal{G}$	set of generators
$\mathcal{B}$	set of branches (lines and transformers)
C	set of postulated contingencies

Optimization variables

P_{Gi}	active power production of the generator at bus i
Q_{Gi}	reactive power production of the generator at bus i
RQ_{Gi}	*effective* reactive power reserve of the generator at bus i
ε_i	fictitious reactive power injection (relaxation variable) at bus i
e_i	real part of complex voltage ($e_i + jf_i$) at bus i
f_i	imaginary part of complex voltage at bus i

Parameters

Q_{Gi}^0	reactive power output of the generator at bus i in the base case
P_{Li}	active power of the load at bus i
Q_{Li}	reactive power of the load at bus i
$P_{Gi}^{\min}$	minimal active power bound of generator at bus i
$P_{Gi}^{\max}$	maximal active power bound of generator at bus i
$Q_{Gi}^{\min}$	minimal reactive power bound of generator at bus i
$Q_{Gi}^{\max}$	maximal reactive power bound of generator at bus i
$V_i^{\min}$	minimal voltage limit at bus i
$V_i^{\max}$	maximal voltage limit at bus i
$I_{ij}^{\max}$	maximal current of the branch ij
w	weighting factor (positive scalar)

active/reactive power production.

These observations motivate the elaboration of a crude first version of a methodology to predict when such issues may start to occur, which is the goal of this paper.

To predict such disruptive operation situations and delay them to the largest extent requires revising the management of sources of *reactive power reserves* (RPRs), coordinating both stages, planning [5] and operation [6,7], so as to ensure that the system disposes of sufficient flexibility [8] to cope with operation variability. The sources of RPRs can be classified, according to their ability to quickly maintain the desired voltage setpoint at a bus, into dynamic (e.g. synchronous generators/compensators, FACTS, controllable RES/storage) and static (e.g. shunt reactors/capacitors).

This paper looks only at the how to optimally manage RPRs of remaining conventional power plants while leaving for future works a more comprehensive VAr planning problem including all above mentioned sources of RPRs.

1.2. Role and characteristics of reactive power reserves

The overarching role of RPRs is to adjust reactive power exchange with the grid in reaction to various disturbances and support reliably the active power flows through the grid. More precisely, the roles of RPRs are to preserve: grid voltages between statutory limits, grid performance (e.g. minimize losses [6]), and ultimately reliable grid operation [9,10].

Unlike active power, which can be transmitted over long distances, a distinctive characteristic of reactive power is that it does not travel far. Hence, since independently of their physical limits, RPRs effectiveness to aid for remote critical operating conditions is limited, the careful management of RPRs is paramount. Therefore, maintaining properly located amounts of RPRs is a key requirement.

1.3. Related works

RPRs technical requirements have been mostly examined in the context of operating constraints enforcement (e.g. statutory voltage limits) [11–13] and voltage stability [11–16]. Furthermore, the provision of RPRs is an ancillary service whose technical performance has to be properly valuated [11,17–19]. As a consequence, extensive efforts have been devoted to valuating the reactive power support [11,17–19] while relatively less attempts have been made to evaluate RPRs [11,13–16]. The value of reactive power reserve must be assessed with respect to its capability of aid the system to face various disturbances and operating scenarios (e.g. contingencies, different demand vs generation patterns, etc.). Despite certain progress, RPRs valuation remains an open research question.

Last but not least, the emerging efforts in coordinating the operations of transmission system operator (TSO) and distribution system operators (DSOs) [20–23] add more complexity to RPRs evaluation, as it has to further consider the reactive power support of active distribution networks to the transmission grid [24,25].

1.4. Paper contributions and organization

The main contributions of the paper are: (i) raise awareness on the key issue of reactive power reserve scarcity as one moves toward 100% RES supply, bringing quantitative evidence underpinning this issue, and (ii) propose a new methodology to gauge the RPRs scarcity which includes the extension of the security-constrained optimal power flow (SCOPF) formulation from [12] to reactive power absorption mode and infeasibility handling. SCOPF problems in general are gaining a lot of momentum today, either through solution efficient approaches (see ARPA-E competition: https://gocompetition.energy.gov) or via extended formulations modelling new needs [26,27].

The remaining of the paper is organized as follows. Section 2 illustrates the issues foreseen in the future power systems operation due to RPRs scarcity. Section 3 presents the proposed tailored AC SCOPF problem formulation to evaluate RPRs. Section 4 provides numerical results with the proposed SCOPF on a small 5-bus system and a 60-bus system. Section 5 concludes and summarizes directions for future work.

2. Illustration of reactive power issues

The operational issues due to the lack or excess of reactive power reserves anticipated in the future in power systems operation are illustrated by a simple example using a slightly modified version of a 5-bus system inspired from [10,28]. The bus data for the two operating conditions investigated, peak load and base (or light/low) load, and branch data are provided in the Tables 1 and 2, respectively, where all notations are self-explanatory.

One considers an energy transition scenario which consists in shutting down sequentially the power plants G4 and G3. One assumes that the lost MW caused by the shut down of a power plant is replaced (at the same bus) by RES operating at unitary power factor. As adequate RPRs have to be available anytime, this is a conservative yet pertinent assumption, further supported with several arguments in Section 1.1. All results are produced relying on basic power flow calculations, contingencies being neglected at this stage.

Table 1
5-bus system data at peak load and base load.

bus	P_L MW	Q_L MVAr	P_G MW	Q_G MVAr	V pu	$P_G^{\min}$ MW	$P_G^{\max}$ MW	$Q_G^{\min}$ MVAr	$Q_G^{\max}$ MVAr
Peak load									
1	1100	400	–	–	0.981	–	–	–	–
2	500	200	–	–	0.978	–	–	–	–
3	–	–	700.0	35.3	1.050	150	1500	−500	750
4	–	–	600.0	190.4	1.050	150	1500	−500	750
5	–	–	330.7	50.5	1.050	150	1500	−500	750
Base load									
1	550	200	–	–	1.031	–	–	–	–
2	250	100	–	–	1.033	–	–	–	–
3	–	–	350.0	−104.5	1.050	150	1500	−500	750
4	–	–	300.0	−84.5	1.050	150	1500	−500	750
5	–	–	156.6	−97.0	1.050	150	1500	−500	750

Table 2
5-bus system: line data.

line	Bus i	Bus j	V^{nom} kV	R_{ij} Ω	X_{ij} Ω	B_{ij} μS	S_{ij}^{nom} MVA
L1	1	2	400	3.2	32	186	1400
L2	1	3	400	6.4	64	375	1400
L3	1	4	400	3.2	32	186	1400
L4	2	5	400	6.4	64	375	1400
L5	3	4	400	6.4	64	375	1400
L6	4	5	400	6.4	64	375	1400

Table 3
Generators reactive power Q_G (MVAr) in various scenarios.

Gen	Base case		Without G4 reserve		Without G3 & G4 reserves	
	Peak load	Base load	Peak load	Base load	Peak load	Base load
G3	35.3	−104.5	151.0	−152.3	0.0	0.0
G4	190.4	−84.5	0.0	0.0	0.0	0.0
G5	50.5	−97.0	153.5	−139.5	461.3	−337.1

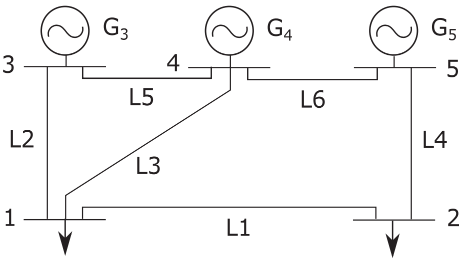

Fig. 1. One-line diagram of the 5-bus system [10,28].

Table 3 yields the generators' reactive power production in the various scenarios. These results show that the overall generators' reactive power production (or absorption) increases as reserves are withdrawn.

Fig. 2 shows, for the peak load base case, the voltage at buses as reactive power reserve of generators G4 and G3 is withdrawn. One can observe that, as the electrical distance between the remaining generators supplying MVArs and loads increases, some voltages (e.g. at buses 1 and 2) fall at unacceptably low values even in the absence of contingencies. Generator G5 produces in the last scenario 461.3 MVAr, which is significantly larger than the initial overall reactive power production of the three generators (276.2 MVAr, see Table 3).

Fig. 3 plots, for base load operating conditions, the voltage at buses as reactive power reserve of generators G4 and G3 is successively cancelled. Note that, as the system is progressively deprived of MVArs absorption capability, voltages raise alarmingly above the maximum limit, particularly at bus 3. This occurs despite the fact that generator G5 does not absorb in the final scenario much more reactive power than the initial overall absorption of all generators (−337.1 MVAr vs. −286 MVAr, see Table 3).

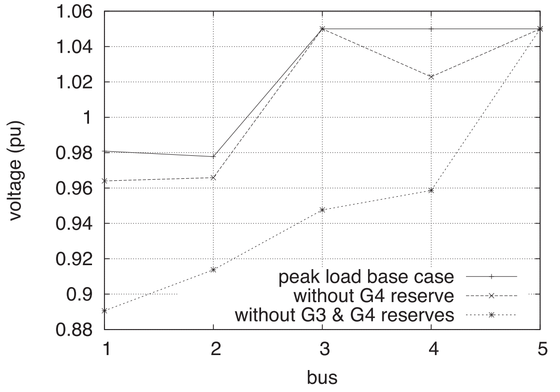

Fig. 2. Peak load bus voltage as generators reactive power production capability is cancelled.

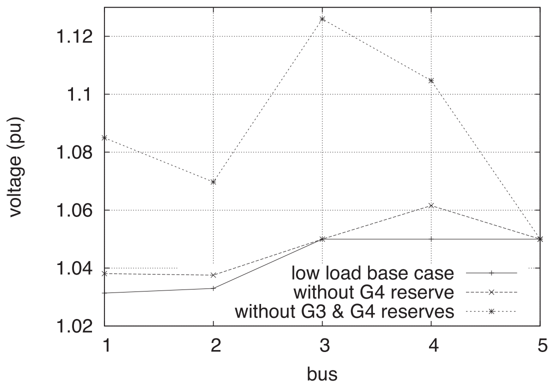

Fig. 3. Base load bus voltage as generators reactive power absorption capability is cancelled.

Table 4
5-bus system: minimum overall needed generators' reactive power reserves (MVAr) in various scenarios.

Base case		Without G4 reserve		Without G3 & G4 reserves	
Peak load	Base load	Peak load	Base load	Peak load	Base load
1051.2	0.0	1350.2	0.0	5.3e+6	1.2e+5

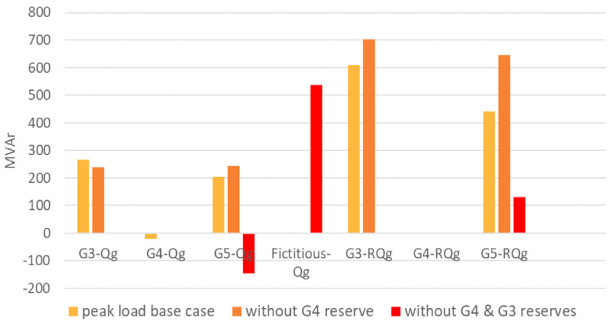

Fig. 4. 5-bus system: generators' effective RPRs in production mode.

From the results shown in both figures one can conclude that, while shutting down generator G4 is harmless, the additional withdraw of reserve of generator G3 harms significantly the grid operation

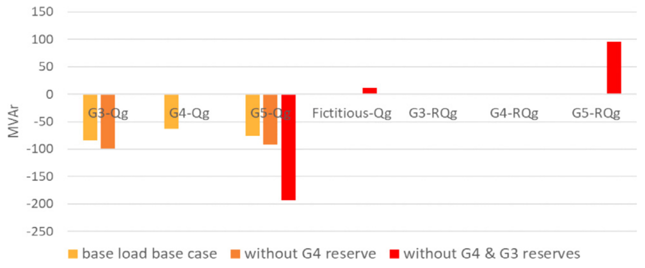

Fig. 5. 5-bus system: generators' effective RPRs in absorption mode.

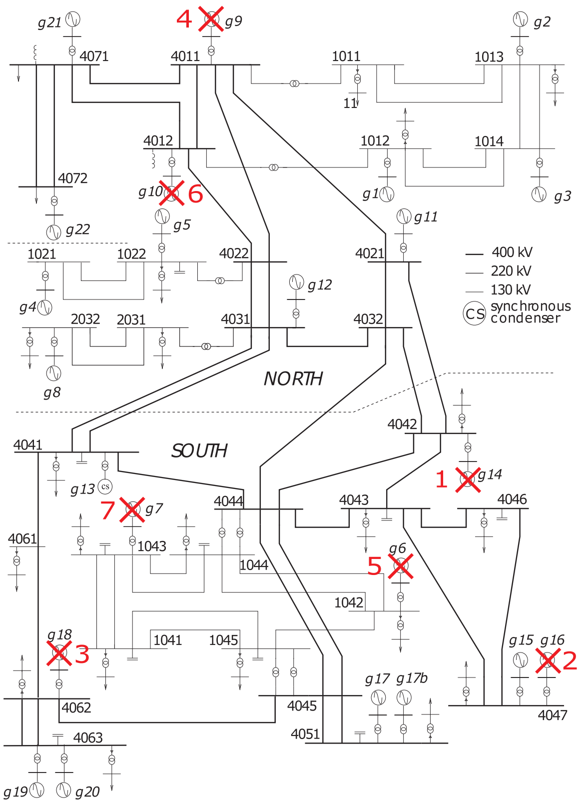

Fig. 6. One-line diagram of the modified Nordic32 system indicating the sequence of power plants phased out.

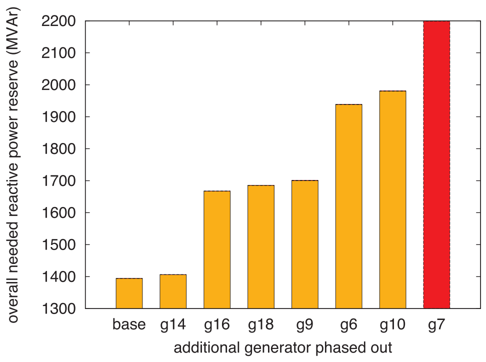

Fig. 7. Overall needed RPRs for the sequence of generators phased out.

constraints. Losing these two generators affects the most the voltage level at the buses 1 (where the largest load is connected) and 3, which are the most distant electrically from the remaining generator G5.

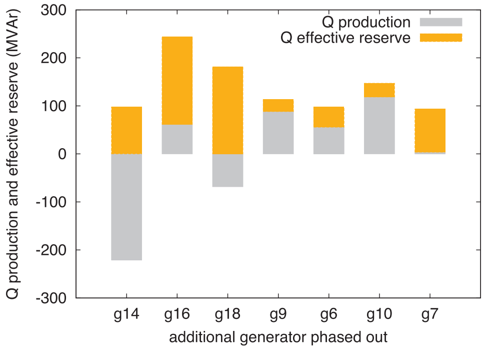

Fig. 8. Reactive power and effective reserve of generators phased out.

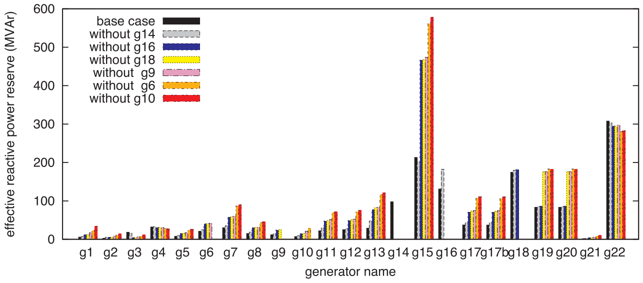

Fig. 9. Effective reactive power reserve as generators are phased out.

3. Reactive power reserves evaluation through tailored AC SCOPF problem formulation

3.1. The proposed methodology

The proposed methodology aims at identifying when, during the most likely scenario of the energy transition, the assumed shut down of some conventional generators causes the RPRs of the remaining conventional power plants to become insufficient for enforcing system security. The proposed metric to evaluate the scarcity of RPRs, modelled by the objective function (1), is the minimum overall RPRs amount of the remaining conventional power plants that is required to maintain security.

Acknowledging that the problem tackled is very complex (several directions of planned future work are described in Section 5), the paper makes a first attempt toward a more comprehensive methodology to evaluate RPRs scarcity. For this reason and for the sake of illustration, the proposed crude first version of the methodology relies on some rough and simple assumptions, particularly concerning the definition of realistic energy transition scenario(s).

As adequate RPRs have to be available anytime, for the sake of illustration simplicity, the RPRs evaluation considers only two extreme operation modes: reactive power *production* (corresponding to *peak load* conditions) and reactive power *absorption* (corresponding to *base load* conditions).

The proposed methodology contains the following steps:

1. Define the energy transition scenario during the assumed time horizon (e.g. up to 2050) as a series of relevant base cases, i.e. virtual operating points of the power system for each extreme operating mode (peak and base load). These base cases are sampled in time (e.g. with a few years step) to capture the shut down of any key generator. A base case differs from the previous in terms of: a new generator being taken out of service (its production being offset by RES hosted mostly in distribution grids) and peak/base load distribution change. The series of base cases reflect hence the sequence of conventional generators to shut down.
2. Pick up the current (non-optimized) base case for each operating

mode: peak load for RPRs production mode and base load for RPRs absorption mode, respectively.

3. Solve the two instances of AC SCOPF problem (presented in Section 3.2) corresponding to the two operating modes to evaluate the generators' RPRs effectiveness[2]in maintaining security.
   If the SCOPF problem is infeasible (case revealed by non-zero fictitious reactive power injection at the solution), then the breaking-point in terms of effective RPRs has been crossed and computations terminate.
4. Select the next base case and go to step 2.

Note that the assumed sequence of generators to withdraw from service is identical in both production and absorption modes.

3.2. AC SCOPF problem formulation

The proposed AC SCOPF problem is formulated hereafter (all notations have been defined in the nomenclature) relying on rectangular coordinates to express bus voltages. The formulation focuses on the reactive power production mode, while the problem adaptation to the reactive power absorption mode will be provided afterward.

3.2.1. Objective function and control variables

The optimization goal is to search for the minimum overall needed reactive power reserves of remaining generators:

$$\min_{RQ_{Gi},P_{Gi}^c,Q_{Gi}^c,e_i^c,f_i^c,\varepsilon_i} \sum_{i\in\mathcal{G}} RQ_{Gi} + w\sum_{i\in\mathcal{N}} \varepsilon_i, \tag{1}$$

where superscript $c \in \{0\} \cup C$ denotes the system state (0 refers to the base case at hand), and the second term of the objective is a penalty function aiming to prevent computation divergence in case of infeasible problems, pointing out hot spots for reactive power compensation.

The control variables of the problem are: generators' reactive power Q_{Gi}^c, generators' effective reactive power reserves RQ_{Gi}, and generators' active power P_{Gi}^c (actually only a few generators are allowed to cover the active power shift while most generators active power is fixed). Other optimization variables are the real and imaginary components of complex bus voltages e_i^c and f_i^c, respectively.

3.2.2. Constraints

Equality constraints encompass the active and reactive power balance equations at each bus $i \in \mathcal{N}$ and for each system state $c \in \{0\} \cup C$:

$$P_{Gi}^c - P_{Li} - \sum_{j\in\mathcal{N}_i^c} P_{ij}^c(e_i^c, e_j^c, f_i^c, f_j^c) = 0 \tag{2}$$

$$Q_{Gi}^c + \varepsilon_i - Q_{Li} - \sum_{j\in\mathcal{N}_i^c} Q_{ij}^c(e_i^c, e_j^c, f_i^c, f_j^c) = 0, \tag{3}$$

where, the well-known formulas of power flows P_{ij} and Q_{ij} have not been made explicit for the sake of formulation compactness.

Inequality constraints in each system state c include thermal limit of grid lines ($ij \in \mathcal{B}$):

$$I_{ij}^c(e_i^c, e_j^c, f_i^c, f_j^c) \le I_{ij}^{\max}, \tag{4}$$

limits on voltage magnitude at each bus $i \in \mathcal{N}$:

$$V_i^{\min} \le \sqrt{(e_i^c)^2 + (f_i^c)^2} \le V_i^{\max}, \tag{5}$$

active power limits of generator $i \in \mathcal{G}$:

$$P_{Gi}^{\min} \le P_{Gi}^c \le P_{Gi}^{\max}, \tag{6}$$

reactive power limits of generator $i \in \mathcal{G}$:

$$Q_{Gi}^{\min} \le Q_{Gi}^c \le Q_{Gi}^0 + RQ_{Gi}, \tag{7}$$

and limits on the needed reactive reserve of generator $i \in \mathcal{G}$:

$$0 \le RQ_{Gi} \le Q_{Gi}^{\max} - Q_{Gi}^0. \tag{8}$$

The proposed AC SCOPF problem formulation in production mode consists in the set of Eqs. (1)–(8). In absorption mode, the problem formulation consists in replacing the set of constraints (7) and (8) with the following constraints (9) and (10):

$$Q_{Gi}^0 - RQ_{Gi} \le Q_{Gi}^c \le Q_{Gi}^{\max}, \tag{9}$$

$$0 \le RQ_{Gi} \le Q_{Gi}^0 - Q_{Gi}^{\min}. \tag{10}$$

4. Numerical results

For the numerical examples that follow, the energy transition scenario consists in removing one generator from service and compensating its active/reactive power production with power injections from distribution networks. However, as sufficient RPRs need to be available anytime during operation, for the sake of conservativeness, the shut down of a power plant assumes that the lost MW is replaced, at the same bus, by renewable energy production operating at unitary power factor.

4.1. Illustration of the methodology using the 5-bus system

The methodology proposed in Section 3.1 is first applied on the 5-bus system shown in Fig. 1. The set of contingencies comprises the loss of any among the 6 lines (see Table 2). The voltage limits are set to 0.75 p.u. and 1.06 p.u. in production mode and 0.95 p.u. and 1.06 p.u. in absorption mode, respectively. The low voltage limit was set to the unusual value of 0.75 p.u. to illustrate the iterations in the methodology in absence of a real network model and realistic energy transition scenarios.

AC SCOPF problems are modeled in GAMS and solved by the local optimizer IPOPT.

Table 4 provides the value of the objective (1), i.e. the minimum overall needed generators' reactive power reserves, in the various scenarios. Note that the effective reactive power reserves are measured for each new base case with respect to Q_G initial values provided in Table 1. Figs. 4 and 5 display the generators' effective reserves and initial reactive power production at the solution of the AC SCOPF problem.

From Table 4 one can observe that, for the peak load case, the needed reserve grows as reserves are withdrawn while, in the last case (i.e. without G3 & G4 reserves), only the reserve of G5 is insufficient to meet the constraints which activates fictitious injections (see Fig. 4) and explains for the large value of the objective. One can further remark that, for the base load case, the objective is zero in the first two scenarios. This is due to the fact that contingencies actually improve the operation conditions as they lead to a decrease of reactive power absorbed.

Note that there is a subtle difference between production and absorption modes of RPRs, since in the former mode a contingency typically weakens the system and necessitates larger reserves, while in the latter mode a contingency usually relieves the system and the intact state is the most constraining for the effective reserves calculation.

4.2. Results using the Nordic32 system

The methodology proposed in Section 3.1 is now applied on the 60-bus Nordic32 system [29]. Fig. 6 shows the one-line diagram of this system, also indicating the sequence of generators shut down (i.e. g14, g16, g18, g9, g6, g10, and g7). The set of contingencies comprises the most critical 33 lines. Using the same rationale of the previous example, the voltage limits are set to 0.75 p.u. and 1.06 p.u. in all states. For

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[2] The *effective reserve* of a generator is the portion of the physical reserve that is needed to maintain security in a certain operation state [12,14].

simplicity, only the production mode is studied.

AC SCOPF problems are solved with using the approach and tool from [12] which implements in C an interior point method.

Fig. 7 provides the value of the objective (1), i.e. the minimum overall needed generators' reactive power reserves, in the various scenarios, where orange boxes denote secure states and red box indicates an insecure state. Note that, after the 6-th generator phased out (i.e. g10), the RPRs are still sufficient to ensure security, while the phase out of the 7th generator leads to security breach and hence an infeasible SCOPF problem. The figure shows an increase of the needed overall reserve as generators are phased out, which is expected, as taking out a generator from service weakens the local reactive power support. This increase is generally slight except some sharp peaks, as for the phasing out of g16, g6 and g7. The amount of this increase depends on the location of the generator phased out, its effective contribution in ensuring security, and efficacy of neighboring generators to compensate its absence. For instance the phase out of g9 is mildly felt thanks to the proximity and ability to take over of generators g21, g22, g11 and g12 (see Fig. 6). Conversely, in the absence of g6, the phase out of g7 leaves the 130 kV grid without local reactive power support as other generators are too remote.

Fig. 8 plots the reactive power production and effective reserve at the moment a generator is phased out. Looking at Figs. 7 and 8 one can remark that, due to the reasons explained in the previous paragraph, the amount of lost effective reactive power reserve and initial generator' production is not necessarily related to the overall needed reserve increase. For example g18 has a relatively large effective reserve but its phase out impacts only slightly the overall reserve as g19 and g20 are close. Conversely, g7 has an insignificant reactive power production and a medium effective reserve, but is worthy since removing it leads to security breach.

Fig. 9 yields the effective reactive power reserve of each generator as some generators are phased out. One can observe that, although the overall needed reserve is consistently increasing (see Fig. 7), for an individual generator the reserve does not always grow (see e.g. g22 and g4), which may occur due to the redistribution of reserves.

5. Conclusions and future works

This paper has explored the major issue of RPRs scarcity as one moves toward renewable-dominated (and ideally 100%) electricity supply. The paper has proposed a crude first version of a methodology to evaluate RPRs scarcity, under an optimal management of such reserves, based on tailored AC SCOPF problem formulations. The proposed methodology has proven being efficient in identifying RPS's breakpoint, i.e. when, during a simplistic most likely scenario of the energy transition, the assumed shut down of some conventional generators will cause the RPRs of remaining power plants to become insufficient for enforcing system security. This outcome can inform grid planner about the timing of reinforcing the reactive power support and the related hot spots as well as constitute a useful input to the foreseen future work on VAr planning, i.e. the question of optimal placement of static or dynamic sources of RPRs.

As the outcomes of the proposed methodology depend on a certain number of assumptions, future work is planned to significantly expand the methodology by incorporating more realistic aspects of potential energy transition scenarios:

- various plausible sequences for power plants phased out and, as a response, sites for RES deployment and participation in active/reactive power ancillary services;
- value of peak/base load and and distribution of load;
- operation generation/demand uncertainties;
- other mutations anticipated to occur during the energy transition e.g. massive deployment of non-RES DERs, TSO-DSO cooperation schemes, etc.

As the non-convex and nonlinear AC SCOPF problems are solved using a local optimizer (based on interior-point method), the obtained solutions are guaranteed to be locally optimal. Today there is no solution method for such non-convex nonlinear programming problems that can converge to the global optimum in the majority of cases. Extensive experiments with methods based on convex relaxations of non-convex and nonlinear AC OPF problems feasible region show that they occasionally converge to the global optimum [30]. Such a convex relaxation method can be employed to provide a lower bound on the objective function and hence gauge the sub-optimality of the solution provided by the local optimizer. However, as extensive empirical evidence shows that the solution provided by local optimizers is the global optimum in most generic AC OPF problem instances [30], there are non-negligible chances that the solution of AC SCOPF problem may be the global optimum.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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