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Analysis of the blackout risk reduction when segmenting large power systems using lines with controllable power flow

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ABSTRACT

Large electrical transmission networks are susceptible to undergo very large blackouts due to cascading failures, with a very large associated economical cost. In this work we propose segmenting large power grids using controllable lines, such as high-voltage direct-current lines, to reduce the risk of blackouts. The method consists in modifying the power flowing through the lines interconnecting different zones during cascading failures in order to minimize the load shed. As a result, the segmented grids have a substantially lower risk of blackouts than the original network, with reductions up to 60% in some cases. The control method is shown to be specially efficient in reducing blackouts affecting more than one zone.

1. Introduction

The European electric power system is composed of 5 main synchronous areas which are interconnected by means of High Voltage Direct Current (HVDC) transmission systems. The different zones are operated independently, also allowing power exchange through the HVDC lines. Fig. 1 shows a map from ENTSO-E (European Network of Transmission System Operators for Electricity) [1] where the different synchronous areas are clearly shown: Continental Europe, Nordic, Baltic, Great Britain and Ireland. The largest synchronous area (shown in Fig. 1) is Continental Europe. The power grid of Continental Europe (defined by ENTSO-E as Continental Synchronous Area) is a 50 Hz frequency electric power system that supplies electricity to more than 400 million customers in 24 European countries. The production capacity of this system is larger than 700 GW. Large system oscillations can happen in large power systems. A recent example [2] occurred last 1st December 2016, when an unexpected opening of a line in the French system triggered an oscillatory incident in the Continental Europe system. These oscillations might lead to important blackouts, like the 2003 blackout in Italy produced by a cascading failure, which affected 55 million consumers.

While, the typical power system engineering planning approach has been for decades to build the largest possible networks, recent studies suggest that such large power systems imply a higher risk of cascading failures and therefore it would be beneficial to segment them [3,4]. As a matter of fact, Ref. [3] suggests that there is an optimal size in terms of security and risk. Small power systems are more vulnerable but very large power systems can have huge blackouts with an extraordinary large associated cost. The trend to segment power systems has already started in China, where the Yunnan zone has been segmented from the main synchronous system where it was connected, to reduce the risk of a cascading blackout [5]. Several studies are considering the option of applying similar measures in Europe or North America [4]. The concept of segmentation is based on the idea of dividing a large alternate current (AC) synchronous area by introducing HVDC lines to interconnect smaller asynchronous zones. HVDC allows to exchange power between the segmented zones while preventing the spread of severe disturbances thanks to active and reactive power control capability of converters. HVDC systems can be operated in different modes, where normally the active power exchange is controlled while controlling reactive power in the different converter stations [6–8]. An alternative option of operating HVDC lines as AC impendances have been used in some practical applications like the Spain–France HVDC interconnection (2 symmetrical monopoles of 1000 MW each) [9]. In addition, due to their superior performance, HVDC is particularly relevant for long distance overhead lines (over 600–800 km) and for underground and submarine cables (over 100 km), including connections to islands and large offshore wind power plants [10].

An example of power grid segmentation is shown in Fig. 2. The upper grid illustrates a modern power system. The grid below shows

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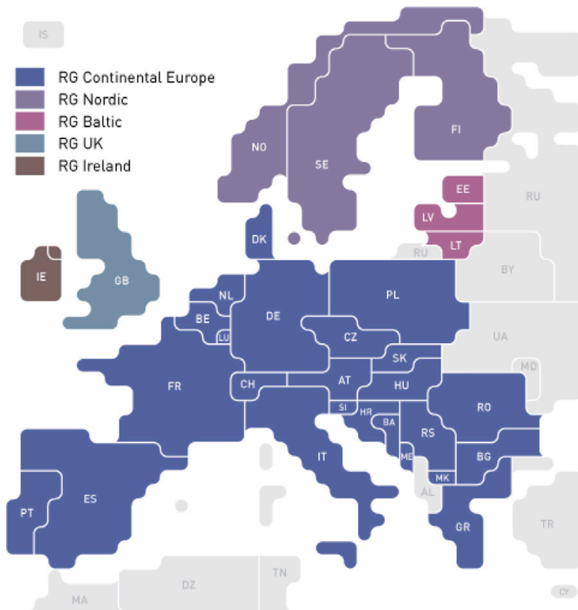

Fig. 1. Synchronous zones in the European power system.
Source: ENTSO-E [1].

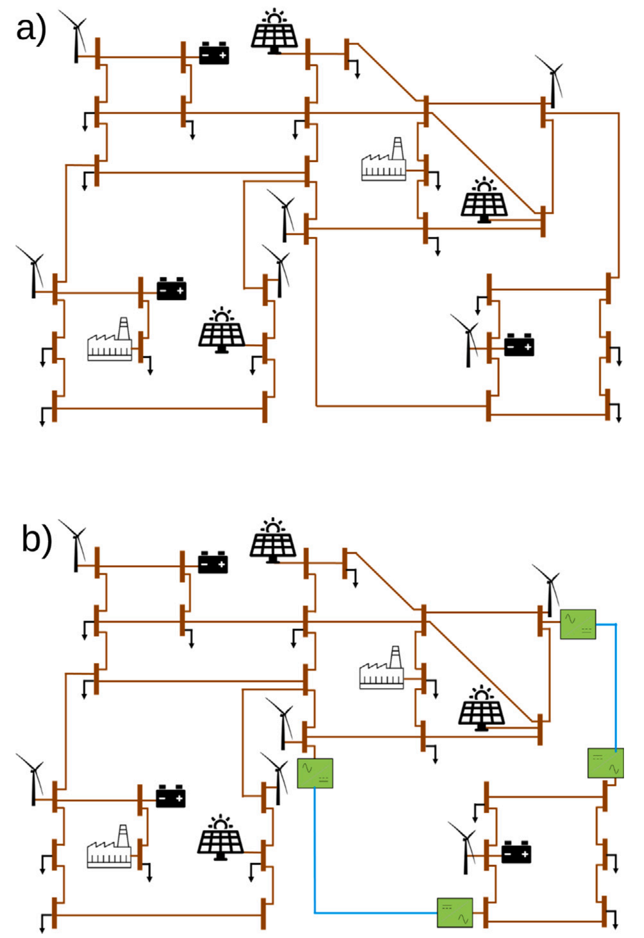

Fig. 2. Example of a power grid segmentation. (a) Scheme of a modern synchronous power grid where all transmission lines are AC. (b) A possible segmentation of the grid into two non-synchronous zones interconnected by two DC lines (in blue).

the result of segmenting the power system using HVDC lines (in blue). HVDC lines require power converters at both ends to convert AC to DC. The two segmented systems correspond to non-synchronous AC zones.

The blackout risk in power networks can be estimated using the ORNL-PSerc-Alaska (OPA) model [11,12]. Several other approaches to model cascading failures and blackouts in electric transmission grids have been proposed in the literature [13–16]. The OPA model is based on a combination of fast and a slow dynamics. The first describes the cascading failures while the second the grid evolution through line and generation upgrades as a respond to failures and demand growth. This way the model brings the power grid continuously to a critical state where random failures may trigger cascading blackouts. The sizes and frequency of the obtained blackouts can then be used to estimate the overall blackout risk of the network. The OPA model has been validated with blackout data from the Western Interconnection in the USA [17–19]. Improvements to the OPA model have been suggested regarding the effects of relay protection and automation on the power flow and the cascading failures, and of planning and operation modes on the slow evolution of the network [20]. For simplicity, in this work we use the original OPA model as it is reliable enough to capture the benefits of the proposed control method on the risk reduction.

In this work we: (i) propose a method to reduce the risk of blackouts by controlling the power flowing through lines interconnecting different zones of a large electrical network during cascading failures; (ii) use a modified OPA model, where we have included lines with controllable impedance as an indirect way to control the power flow, to evaluate the risk of blackouts; and (iii) we consider the Balearic Islands transmission network [21] as a case study to analyze the effects of this methodology on a real network.

The paper is structured as follows: In Section 2 we describe the OPA model, discuss the required changes to implement the control of the line impedance, and describe the used networks of networks. In Section 3 we present the results obtained for artificial networks, and in Section 4 for a model of the Balearic Islands transmission grid. Finally, in Section 5 we give some concluding remarks.

2. OPA model including variable impedance lines

The OPA model represents the loads and generators of an electric grid using a standard DC power flow approximation [11,12]. OPA models the electric grid dynamics on two timescales: a fast timescale in which blackouts are simulated through a process of cascading outages of transmission lines and a slow timescale describing the evolution over years in which daily demand has random variations on top of a secular increase (0.005% daily, approximately 2% per year).

In the original OPA model, every day, power is dispatched to cover the demand. Transmission lines have a failure probability rate p_0 due to a random event. A line outage is a potential trigger of a cascade: in the event of a failure, power is redispatched using the remaining available lines. If, as a result of the dispatch, a line is overloaded, it can fail instantaneously with a probability p_1. A line connecting nodes i and j is considered overloaded when the ratio of the power transmitted to the power flow limit reaches the value 0.9. The fault of a line is implemented in the model by increasing its impedance very much, effectively removing the line from the grid. This models either the breaking of the line or the activation of a protective relay. Power is then dispatched again and again using the remaining lines until no more failures are produced. The final solution may have some load shed, L_S. If the ratio of the load shed to the total power demand, $S \equiv L_S/P_D$, is larger than a certain value, $S > S_b$, the event is considered a blackout. The restoration after a blackout is assumed to take place in the same day, such that the next day the dispatch is done with the full network.

The OPA model assumes that after a blackout, the parts of the system involved are upgraded. More precisely, the lines that have experienced overloading or outages have their flow limit increased by a factor $\mu > 1$.

The generation capacity margin ΔP_{G} is the difference between the total generation capacity P_{G} and the power demand P_{D}, normalized to the power demand: $\Delta P_{\mathrm{G}} = (P_{\mathrm{G}} - P_{\mathrm{D}})/P_{\mathrm{D}}$. Generators are upgraded yearly if the annual average value of the capacity margin goes below a predetermined critical value, $\Delta P_{\mathrm{G}}^{c}$, by increasing the generation capacity by a factor $\nu > 1$. In this way, the system copes with the continuous increase in demand.

Altogether, the OPA model simulates a power grid that always operates close to its critical capacity, identifying the most probable causes of failure in the system over the years.

Networks of networks

To build networks of interconnected networks we use building-blocks each consisting of 100 or 200 nodes. These are synthetic power grids with realistic parameters and topology which have been constructed following the algorithms explained in [22]. Then we take copies of these building blocks and connect them using a few lines (see Figs. 3 and 4). The OPA parameters are taken from [17]. The approach that we follow in selecting the nodes to interconnect is to reduce the average of the shortest distances (here distance really means resistivity) between all nodes. This approach has been proven to be the most effective in reducing the risk of blackouts for these type of networks [23,24]. Using two or three interconnection lines (marked in red in Figs. 3 and 4) between each of the sub-networks, which from now on we will call zones, is already rather effective as discussed later. The nominal impedance of the interconnections is similar to those of the rest of the lines. These lines will be later controllable.

Based on these results, we build homogeneous networks by combining several zones of the same size (Fig. 3). We consider both the case in which generation and consumption is balanced in each zone (homogeneous balanced networks) and that in which generation and consumption is only balanced at the overall network of networks level, while zones are intrinsically unbalanced (homogeneous unbalanced networks).

We will also study heterogeneous networks composed of zones of different sizes, as the case shown in Fig. 4, consisting of a network formed by a zone with 200 nodes and two zones with 100 nodes. A network with one zone of 200 nodes and one zone of 100 nodes will be also included in the analysis. For heterogeneous networks we will take balanced production and consumption in each zone.

In this work we have modified the OPA code to control the impedance of the interconnection lines in order to check if the reliability of the system can be improved by tuning the power flowing through these lines during blackouts. Controlling the impedance is an indirect way to control the power flowing through a line in our model. In practice, a direct way to implement such control would be using HVDC lines [25]. For this reason, from now on, we will refer to the controllable impedance lines as HVDC lines for short. Although we use this term, our model does not include any specific feature of the HVDC technology beyond the power flow control capability. We consider also that HVDC lines have the same nominal capacity and failure probability as the conventional AC lines they substitute, therefore not worsening system security a priori but, thanks to its control capabilities, increasing its resilience against blackouts. Economical and other technical issues beyond the blackout risk reduction will be analyzed elsewhere. Other technologies could also be used to control the power flowing through a line.

The control is applied following a Monte Carlo optimization approach: when doing the dispatch, if the result is that there is a non-zero load shed, we calculate N_d dispatches with random values for the impedance of each HVDC line and select the one that minimizes the load shed. Random samples for the impedance of HVDC line i are chosen in the interval $[Z_i/k, kZ_i]$ where Z_i is the nominal impedance, taken equal to the impedance of AC lines. Samples are distributed uniformly in logarithmic scale so that there are as many possible samples above and below Z_i. On one side, large values of the impedance largely

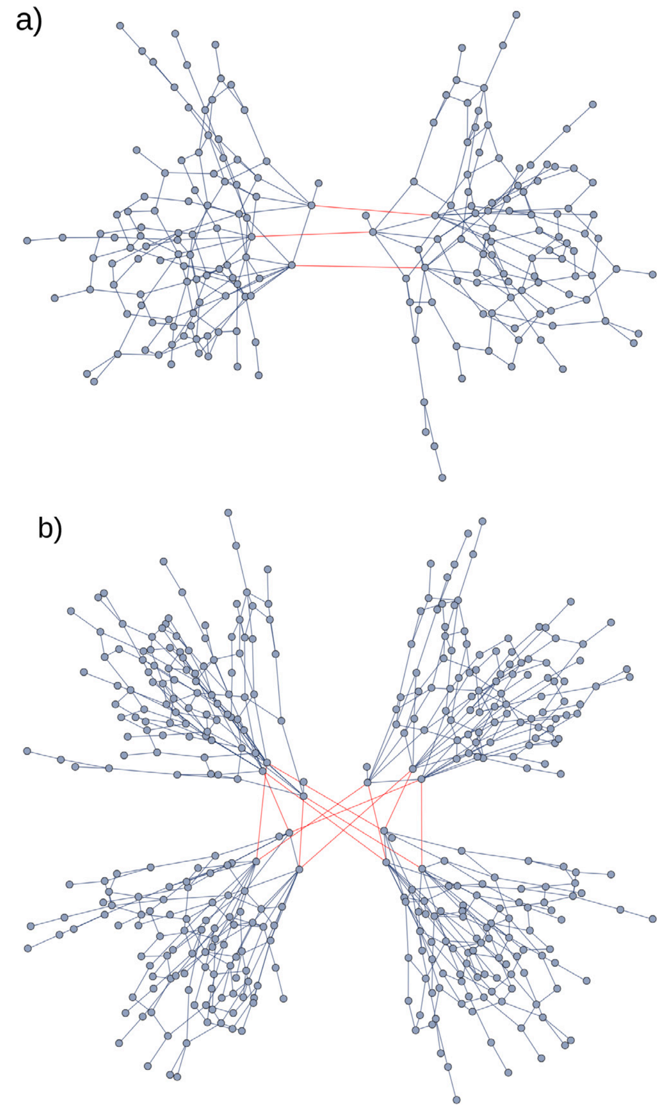

Fig. 3. Two networks constructed by interconnecting (a) two and (b) four 100-nodes zones with three HVDC lines between each pair (red lines). The two and four zones networks have a total of 306 and 616 lines respectively. For these networks we take the following parameters for the OPA model: $p_0 = 0.00025$, $p_1 = 0.05$, $S_{\mathrm{b}} = 10^{-3}$, $\mu = 1.08$, $\Delta P_{\mathrm{G}}^{c} = 0.2$, $\nu = 1.08$.

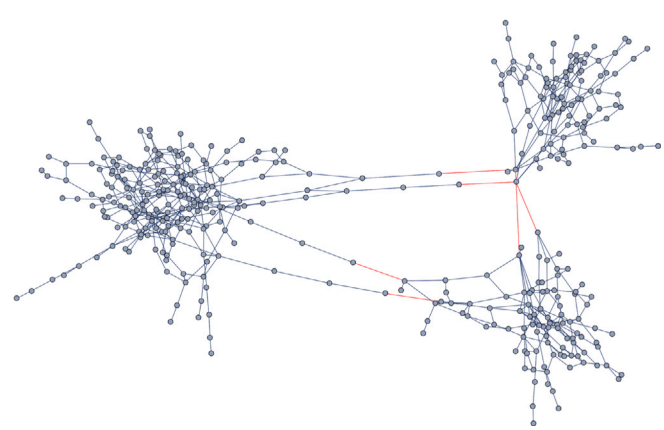

Fig. 4. An unbalanced network with a total of 613 lines constructed by interconnecting one 200-nodes zone with two other 100-nodes zones using two HVDC lines (in red) between zones.

reduce the power flowing through HVDC lines, effectively isolating the different zones of the network and avoiding the propagation of blackouts. On the other, small values of the impedance increase the power flowing through these lines, allowing a larger interchange of energy between zones and mitigating the load shed in a zone due to a generator or line failure by bringing energy from neighboring zones. Having a sufficient range of variation of the impedance is therefore important for the method to be effective. In principle the larger k the better, however, in practice, larger values of k exponentially increase the number of possible combinations to be explored with the Monte Carlo method, making it computationally increasingly costly. We find that $k = 10$ is a reasonable compromise between effectiveness and computing time, and we will use this value henceforth. Also, increasing the number of controllable lines would increase the control capacity, however including this technology in existing grids can be quite expensive and a cost–benefit analysis would be necessary to determine the optimum number from an economical point of view. Moreover the computing time also increases with the number of controllable lines. We find that, as shown in Section 3, using only two or three interconnections between zones works one obtains substantial reductions of the blackout risk.

To quantify the impact of introducing HVDC lines between zones we analyze the frequency and the risk of blackouts with respect to the reference case of connecting zones with fixed impedance lines. The probability of having a blackout whose relative load shed is S is [3]:

$$\lambda(S) = f \times p(S), \tag{1}$$

where f is the frequency of blackouts and $p(S)$ is the size probability distribution of blackouts. $S \equiv L_\mathrm{S}/P_\mathrm{D}$ is a measure of the relative size of the blackout.

The risk, instead, is a measure of the global cost of the blackouts. We consider the cost of a single blackout proportional to the lost energy. Assuming that the duration of a blackout is proportional to its relative size, S, the lost energy is computed as the power loss, L_S, times the duration of the blackout. Then the risk of the network is given by:

$$\mathrm{Risk} = A \int \lambda(S) S^2 P_\mathrm{D}^2 dS. \tag{2}$$

Because the constant A is undetermined, we normalize the risk to the reference case with fixed impedance connections. This quantity has properties similar to those of the standard system average interruption frequency index (SAIFI), which measures the average number of interruptions that a customer experiences [21]. We will also compare the rank of the size of blackouts to analyze the effectiveness of the control method. The rank is defined as:

$$\mathrm{Rank}(S) = 1 - \int_0^S p(x) dx. \tag{3}$$

An important parameter of the Monte Carlo optimization is the number, N_d, of combinations of random impedance values that we try to select the best. The philosophy behind this method is that there is a number of combinations that may give a similar result and that one needs to explore a sufficiently large number of possibilities to have a reasonably high probability of finding one of the good set of impedance values. In Fig. 5 we show the risk reduction we obtain as a function of the number of Monte Carlo samples N_d for the networks shown in Fig. 3. We observe that the values above $N_d = 200$ give reasonable converged values for the risk, indicating that with this number we find optimal values of the impedance to reduce the risk. In this work we will use $N_d = 400$ samples in our calculations.

3. Minimization of the blackout risk for interconnected networks

For the homogeneous balanced networks shown in Fig. 3 we first evaluate the blackout size distribution considering that connections between zones are standard lines with fixed impedance, case we take as reference. We then evaluate the blackout distribution for the case

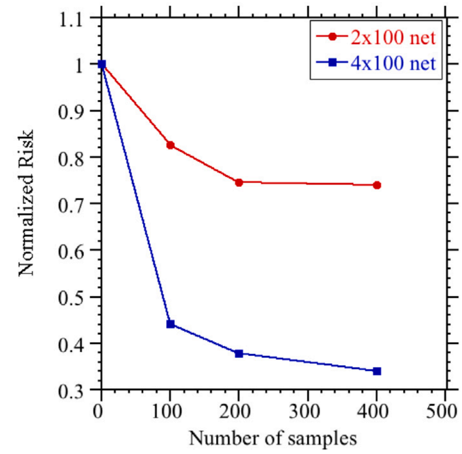

Fig. 5. Normalized risk as a function of the number of Monte Carlo samples, N_d for the networks shown in Fig. 3 composed of two (red circles) and four (blue squares) zones each with 100 nodes.

Table 1
Blackout frequency and risk when using HVDC lines with respect to the reference case for homogeneous balanced networks.

Network	Frequency ratio	Risk ratio
2 × 100	0.96	0.75
4 × 100	0.96	0.38
Balearic grid (2 zones)	1.03	0.72

in which connections between zones are made with HVDC lines where the value of their impedance is set using the Monte-Carlo optimization procedure explained in Section 2. A summary of the main results is given in Table 1. In this table we present the ratio of the blackout frequency and the risk with respect to that of the reference case. The smaller the ratio the better the performance of the control method. The case of the Balearic grid will be discussed in Section 4.

As shown in Table 1, the blackout frequency is practically the same as the reference case, but the risk is reduced in a significant way. This risk improvement comes from the reduction of the size of the largest blackouts. This can be seen in Fig. 6 for the rank of the load shed normalized to the total power demand, S, for the 4×100-nodes network. The reduction of the size of the largest blackout when using HVDC lines can be appreciated in the slope of the tail of the rank distribution. The largest blackouts are the ones with heavier weight in costs to communities, hence the reduction of the risk shown in Table 1. We note here that this a very interesting result, because is the first time that we study a control method for the blackouts that reduces the risk without increasing frequency of the blackouts, as usually observed in other control methods [26–28].

During a blackout cascade, the impedance of the HVDC lines is selected following the Monte Carlo optimization discussed in Section 2. We define the ratio f_i of the selected impedance for HVDC line i with respect to its nominal impedance Z_i. We then introduce the average of f_i over HVDC lines and over blackouts of a specific size:

$$\mathcal{F}(S) = \frac{1}{N_\mathrm{HVDC}} \sum_{i=1}^{N_\mathrm{HVDC}} \langle f_i \rangle_S , \tag{4}$$

where $\langle \rangle_S$ stands for averaging over blackouts of relative size S and N_HVDC is the number of HVDC lines. We also compute the associated standard deviation

$$\sigma^2_\mathcal{F}(S) = \frac{1}{N_\mathrm{HVDC}} \sum_i \left\langle \left| f_i - \mathcal{F}(S) \right|^2 \right\rangle_S . \tag{5}$$

The average $\mathcal{F}$ and the dispersion $\sigma_\mathcal{F}$ provide indications on the way the control system acts. Fig. 7 shows $\mathcal{F}$ as a function of the relative

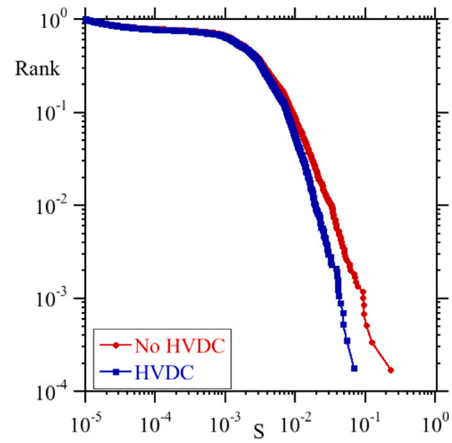

Fig. 6. Rank function of the normalized load shed for the balanced 4 × 100 node network using standard lines to interconnect zones (red symbols) and using controllable impedance HVDC lines (blue symbols).

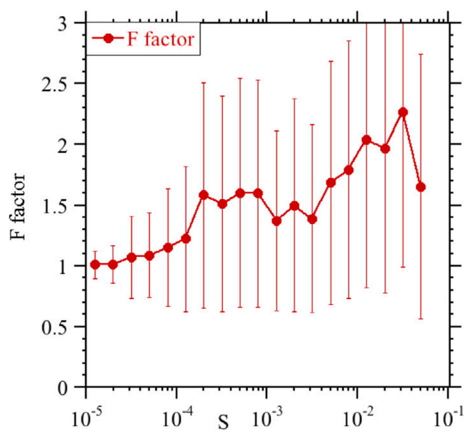

Fig. 7. Average impedance ratio $\mathcal{F}$ as defined by Eq. (4) as a function of the blackout size. The bars indicate the standard deviation of the data $\sigma_{\mathcal{F}}$ as defined by Eq. (5).

blackout size S for the 4 × 100 network. Vertical bars correspond to $\sigma_{\mathcal{F}}$. $\mathcal{F}$ increases steadily with the blackout size. This reflects the situation in which, as the blackout size increases and mores zones are involved, the control tends to increase the impedance of the interconnection lines to avoid the propagation of the cascades, acting as if they were firewalls. The dispersion of the values of the impedance found by the Monte Carlo method is, however, very large, including sometimes values of the impedance smaller than the nominal values ($f_i < 1$). This corresponds to situations in which allowing more power to flow through the interconnection lines reduces the load shed in a zone thanks to power coming from neighboring zones.

We have also considered the homogeneous 2 × 100 and 4 × 100 networks with unbalanced generation among the zones. For both cases, we consider that half of the zones have a installed power four times larger than the others. Additionally we have considered the two heterogeneous networks discussed in Section 2 (200+2 × 100, shown in Fig. 4 and 200+100). The results for blackout frequency and risk are summarized in Table 2.

For unbalanced homogeneous networks results are similar to the case of balanced networks, risk is reduced without increasing the blackout frequency, although the risk reduction is a bit smaller. In Fig. 8, we show, for instance, the change of the rank function for the 4 × 100 unbalanced network. For heterogeneous networks the performance of

Table 2
Blackout frequency and risk when using HVDC lines with respect to the reference case for unbalanced and heterogeneous networks.

	Network	Frequency ratio	Risk ratio
Unbalanced	2 × 100	0.93	0.74
	4 × 100	0.95	0.61
Heterogeneous	200 + 100	0.99	0.78
	200 + 2 × 100	0.86	0.97
	Balearic grid (3 zones)	0.98	1.08

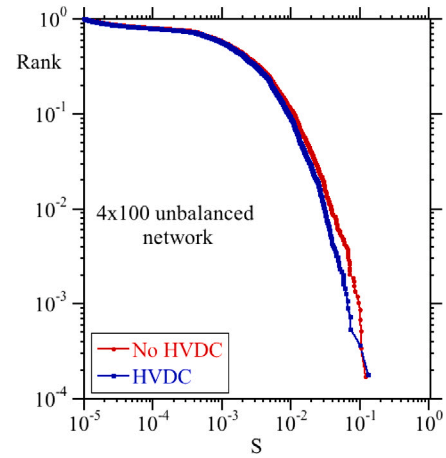

Fig. 8. Rank function of the normalized load shed for the unbalanced 4 × 100 node network using standard lines to interconnect zones (red symbols) and using controllable impedance HVDC lines (blue symbols).

the control is more limited and results depend substantially on the degree of heterogeneity.

We next analyze the results disaggregated by the number of zones involved in the blackouts. We consider that a blackout affects a zone j if the ratio of the zone load shed $L_{S,j}$ to the zone power demand $P_{D,j}$, $S_j \equiv L_{S,j}/P_{D,j}$, is larger than a certain value, $S_j > S_b = 10^{-3}$. In Fig. 9 and Fig. 10 we plot the risk and frequency of the blackouts as a function of the number of zones they affect for the 2 × 100 and 4 × 100 homogeneous balanced networks respectively. The risk is normalized to that obtained for the overall network with standard interconnections between the zones. We first consider the case with standard (AC) interconnections (red and orange symbols). For two zones (Fig. 9) we observe that the risk (red circles) and frequency (yellow diamonds) of blackouts affecting two zones are smaller than the risk and frequency of those affecting one zone. However for the four zones case (Fig. 10) the risk of blackouts (red circles) is not a simple decreasing function with the number of zones involved, because, although the frequency (yellow diamonds) decreases with the number of zones, blackouts affecting many zones have larger sizes and thus entail a higher risk. Next we consider the effect of using HVDC interconnections. The risk of blackouts decreases regardless the number of zones involved (compare blue squares with red circles). Note that for the 4 × 100 networks the reduction is particularly important for blackouts involving a larger number of zones. This is so because the main effect of the control on the HVDC lines is avoiding the propagation of cascading blackouts from one zone to another. The frequency of blackouts shows minor changes: is slightly reduced in the case of two zones but it shows a small increase for 4 zones (compare violet triangles with yellow diamonds).

The control is effective in decreasing the risk of the multiple zones blackouts by avoiding the propagation of the cascades, but it also works to reduce the risk of single zone blackouts by providing generation from other zones. For this reason it is important to provide a broad range of values for the impedance so that values smaller or large than the nominal impedance can be chosen by the Monte-Carlo method

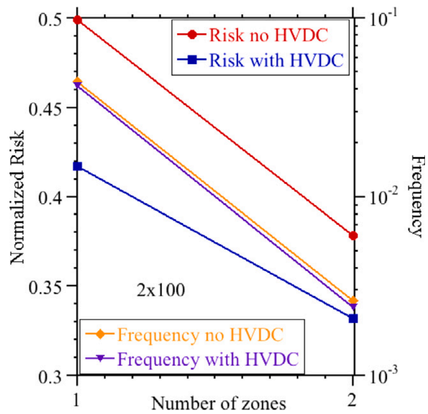

Fig. 9. Risk and frequency of blackouts for the 2 × 100 homogeneous balanced network shown in Fig. 3(a) as function of the number of affected zones. The risk of blackouts affecting one zone is reduced by 16% and those affecting two zones by 13%. The frequency of blackouts is essentially not affected by the control.

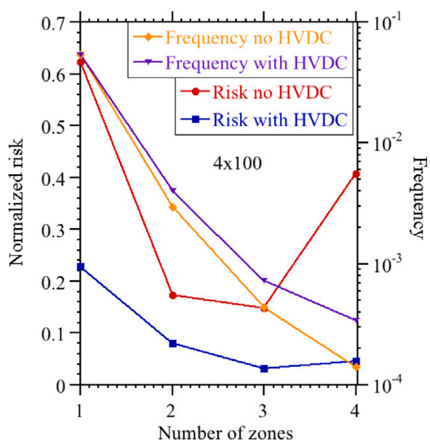

Fig. 10. Risk and frequency of blackouts for the 4 × 100 homogeneous balanced network shown in Fig. 3(b) as function of the number of affected zones. The risk of blackouts affecting one, two, three, and four zone is reduced by 64%, 53%, 80%, and 88% respectively. The frequency of blackouts is only marginally affected.

depending on each of these situations. We have repeated the same analysis for unbalanced and heterogeneous networks. Fig. 11 shows the risk of blackouts as a function of the number of zones they involve. The risk is clearly reduced by using HVDC lines in all cases except for the 200+2 × 100 network. In this case the risk of blackouts involving two zones does not decrease with control, nor does the overall risk without discriminating by zones (see Table 2 and Fig. 12).

From our results we conclude that the proposed control method is globally more efficient in the case of interconnected networks of similar sizes, the reason being that, otherwise, the risk is predominately determined by the weight of the largest network. As a matter of fact, in Fig. 13 we shown the number of large blackouts which have affected one, two, or three zones for the 200+2 × 100 network. We take here as large blackouts those affecting more that 3% of the load. We observe that, when including the control, although the number of blackouts affecting three zones has decreased, the number of blackouts affecting one or two zones, that include the largest sub-network, have increased, and they can be quite large, as the largest network accounts for an important fraction of the demand. Locally, the method is still effective in reducing the risk of the blackouts affecting a single small zone.

4. Minimization of the blackout risk for the Balearic islands network

In this Section we consider a model for the Balearic Islands transmission grid (Fig. 14) [21]. It comprises 61 nodes interconnected by 88 lines divided among 4 islands connected by AC submarine cables (indicated in magenta in the figure). There are 8 generator nodes indicated in blue. There is also a high-voltage DC cable connecting the islands with the mainland grid, which in this study is replaced by an equivalent additional generation capacity in conventional power plants.

A natural choice to segment the Balearic power grid is considering the submarine cables connecting the different islands to have controllable impedance, which leads to a network with 3 zones. The results obtained for the risk are summarized in Table 2 and in Fig. 15. We find that, in this case, no reduction of the risk of blackouts is observed. The main reason is, as in the case of the heterogeneous 200+2 × 100 network, that the island of Mallorca is much bigger that the other two, and the blackouts, or part of the blackouts, occurring within it weight too much and are not affected by controlling the impedance of the cables connecting Mallorca to the smaller islands.

We then propose segmenting the grid in two parts of similar size (2 zones), so that the zones are more homogeneous and balanced. To do so, we have chosen to control the impedance of the five lines marked in magenta in Fig. 16, which divides the network approximately in two halves. Repeating now the same analysis for this network we do observe a substantial reduction in the risk of the blackouts (see Table 1 and Fig. 17).

5. Conclusions and outlook

We have proposed a method to reduce the risk of blackouts in electrical power transmission networks by controlling the power flowing through certain lines. These lines can be the existing HVDC lines interconnecting different synchronous areas or new HVDC lines replacing AC lines connecting different zones within the same synchronous area, thus segmenting the power system.

We have used the OPA model to evaluate the changes in the risk of blackouts as a result of the segmentation. The HVDC lines and converters are modeled in this study as lines with controllable impedance. Changing the impedance is a way to control the power flowing through a line in our model. In a cascading failure the control method consist in choosing an appropriate value of the impedance, i.e. the power flow, for each HVDC line to minimize the load shed of the subsequent blackouts. This is done at dispatch by simulating a priory the cascade many times, each with different impedance values, in a Monte Carlo fashion, and selecting the configuration that minimizes the load shed. Our results show that: (i) this method can reduce the risk of blackouts of a homogeneous balanced segmented grid up to 60% with respect to the original full AC network; (ii) the method is particularly efficient in suppressing blackouts affecting more than one zone; (iii) in unbalanced or heterogeneous networks the global effectiveness is reduced, as the risk is determined mainly by the blackouts in the largest zone, however a substantial reduction of the local risk is still obtained in the smaller sub-networks; and (iv) this method is able to decrease the risk of blackouts without increasing its frequency, a counter effect typically found in other control methods.

In a real set up, the simulations to determine the proper value of the power flow should be done in real time during the cascading failure. While this is possible using sufficient computational power, more efficient ways of determining the optimal power flow value should be pursued. Some insight about the values selected by the Monte Carlo method is given by Fig. 7, where a tendency to take larger values of the impedance for larger blackouts can be appreciated, although the variability in the selected values is very large, and in some cases small values for large load sheds are taken. Using machine learning techniques to determine the optimal values of the impedance could possibly improve the velocity of the method.

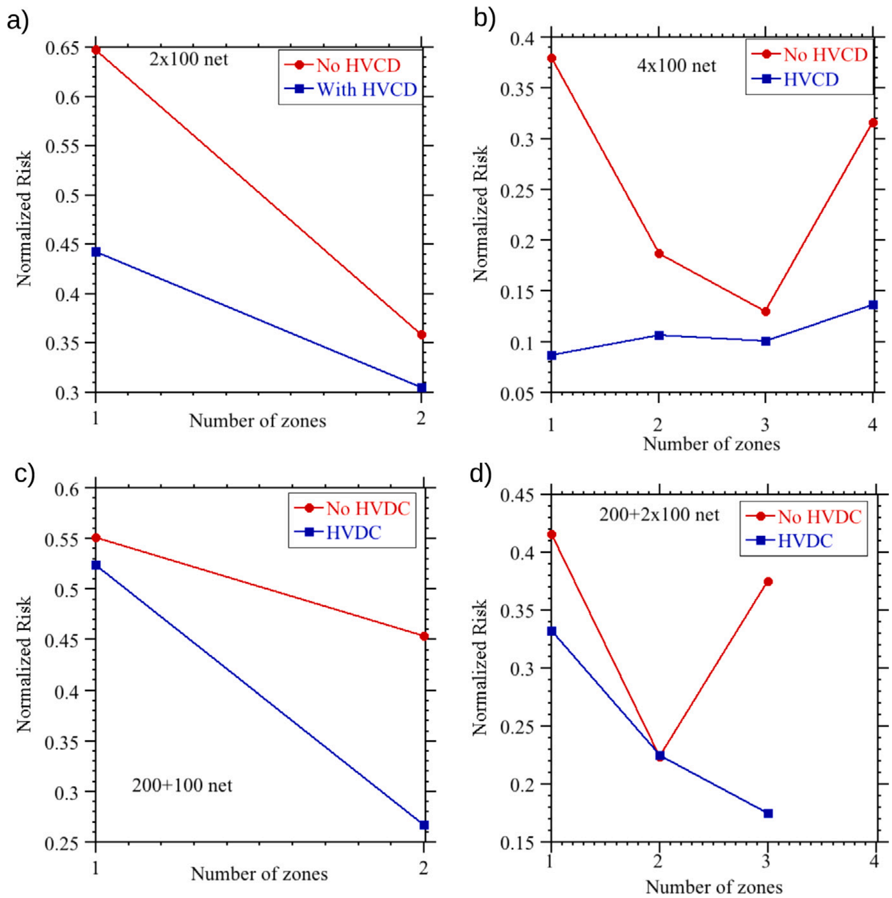

Fig. 11. (a) Risk of the blackouts as function of the number of zones affected for: (a) an unbalanced homogeneous network composed by two 100-nodes zones; (b) an unbalanced homogeneous network composed by four 100-nodes zones; (c) a heterogeneous network formed by a 200-nodes and a 100-nodes zones; and (d) a heterogeneous network formed by a 200-nodes and two 100-nodes zones.

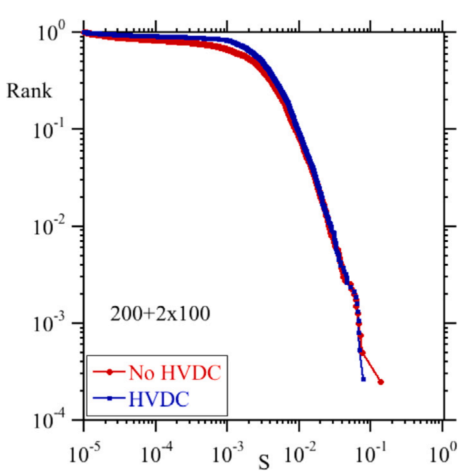

Fig. 12. Rank function of the normalized load shed for the 200+2 × 100 node network using standard lines to interconnect zones (red symbols) and using controllable HVDC lines (blue symbols). No reduction of the blackout sizes is observed in this heterogeneous case.

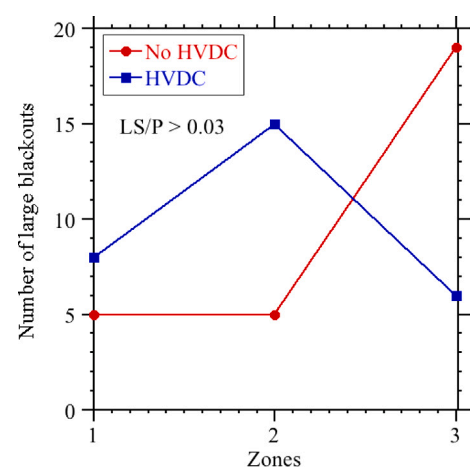

Fig. 13. Number of blackouts with a load shed larger that 3% of the demand disaggregated by the number of zones they have affected for the 200+2 × 100 node network, using standard lines to interconnect zones (red symbols) or controllable impedance HVDC lines (blue symbols).

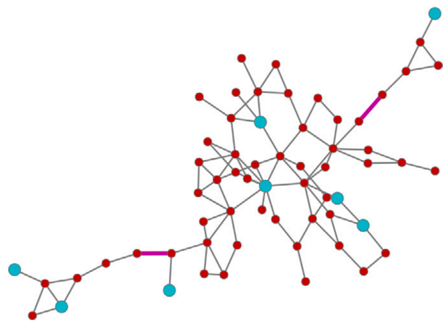

Fig. 14. Network model of the Balearic transmission power grid used a case study. The power grid has 62 nodes and 89 lines divided among 4 islands connected by AC submarine cables. There are 8 generator nodes (blue nodes).

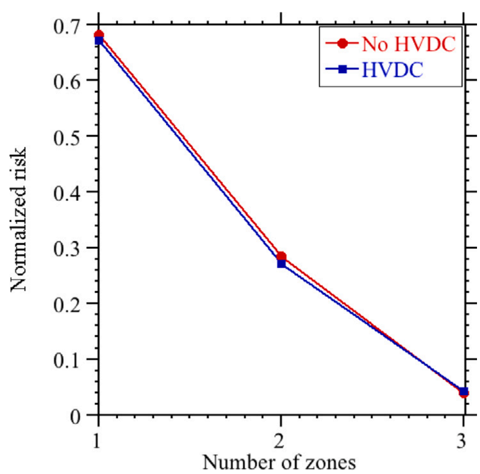

Fig. 15. Risk of blackouts involving different number of zones for Balearic Island transmission network controlling the impedance of the submarine cables between islands. Here, according [21], we take: $p_0 = 0.0003$, $p_1 = 0.2$, $S_b = 10^{-5}$, $\mu = 1.04$, $\Delta P_G^c = 0.4$, $\nu = 1.04$.

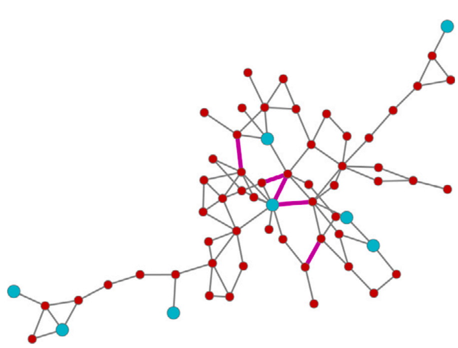

Fig. 16. A model of the Balearic Island transmission network including HVDC lines (marked in magenta) to segment the power grid in two halves.

CRediT authorship contribution statement

D. Gomila: Conceptualization, Methodology, Writing – original draft. **B.A. Carreras:** Conceptualization, Methodology, Software, Writing – original draft, Visualization, Investigation. **J.M. Reynolds-Barredo:** Methodology, Software, Writing – review & editing. **P. Colet:** Conceptualization, Methodology, Writing – review & editing. **O. Gomis-Bellmunt:** Conceptualization, Writing – review & editing.

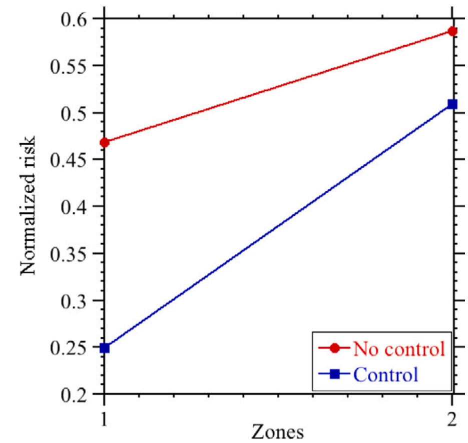

Fig. 17. Risk of blackouts involving different number of zones for Balearic Island transmission network segmented as shown in Fig. 16.

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.

Data availability

Data will be made available on request.

Acknowledgments

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