Assessing Blackout Risk With High Penetration of Variable Renewable Energies

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ABSTRACT

We propose a method to analyze the risk of blackouts with high penetration of variable renewable energy sources (VRESs). We consider a model for the long-term evolution of the power grid including propagation of cascading failures, day-to-day fluctuations of renewable generation and moderate use of storage. We analyze grid resilience and stress as VRESs are progressively incorporated. We also evaluate the VRES performance as the average fraction of daily demand covered by renewables. We find that in general, VRES intrinsic variability increases the grid stress and the blackout risk. However, if VRESs are implemented in a distributed way, the spatial spreading of the generation may have a positive effect on grid resilience. As a case study, we analyze the replacement of conventional power plants by solar photovoltaic generation combined with storage in the power grid of the Balearic Islands. We also consider the use of source redundancy and briefly discuss the potential of wind energy.

INDEX TERMS

Energy transition, island decarbonization, OPA model, power transmission grid, variable renewable energy sources.

I. INTRODUCTION

The necessity to reduce greenhouse gas emissions to combat climate change and reduce the dependence of modern society on hydrocarbons is progressively shifting the energy sector from conventional to renewable energy sources (RESs), especially in electricity production. Countries worldwide have roadmaps to achieve a given percentage of renewable energy in their mix over the next years or decades. This energy transition is particularly pressing on islands, where electricity production relies mostly on fossil fuels, despite the great RES potential of these islands. However, their power grid, typically not directly connected to the continental grid, is also relatively small and thus more vulnerable to demand fluctuations and failures in transmission lines and power plants.

Numerous reports indicate the massive potential of RESs to provide the necessary energy to run modern societies [1], [2]. For instance, in the Balearic Islands, which we use as a case study in this work, it is estimated that to cover 100% of the electrical needs with photovoltaic energy, it would be necessary to occupy less than 2% of the total land [2]. These studies are typically based on generating enough energy to cover the annual consumption taking into account factors including mean solar irradiation for solar plants, average wind at certain locations for wind farms, proportion of land use, etc. However, the problems arising from integrating a high share of time variable RESs (VRESs) in the existing power grid are complex, and all studies agree on the need to include energy storage due to VRES intermittency. Indeed, integrating high ratios of solar and wind energy in the electric power grid keeping its reliability is a challenging and costly task [5]. In [6], for instance, the US power system is considered to have photovoltaic
energy penetrations exceeding 50% of the total annual production. The authors find that while there are many hours in which over 90% of the demand is covered by solar energy, there is significant curtailment even with high levels of storage. Similarly, a study of the Texas grid system considers scenarios with 55% VRES penetration and concludes that 8 hours’ worth of storage can reduce curtailment to half, but further storage capacity has rapidly diminishing returns [7].

A different approach suggests that overbuilding, also referred to as source redundancy, and curtailment may be a convenient strategy to mitigate VRES intermittency and reduce costs [9]. In all cases, the problem of determining the optimum VRES penetration and amount of storage does not have a unique answer, but different criteria may apply to each case [10]–[12]. All these studies analyze the feasibility of integrating high shares of variable renewable energy, focusing on the effects of the variability on the dispatch of energy and the need for storage and grid flexibility to avoid excessive renewable energy curtailment. Other works address the difficulties that VRESs introduce in the voltage and frequency management of power grids, especially microgrids where fluctuations have a much larger relative size [13]. For this task, energy storage systems are again very effective in improving the supply quality [14]. While these studies demonstrate to a great extent the possibility of operating power systems with a very high penetration of VRESs and storage, the effect on the long-term evolution of the electric system in terms of probability and sizes of blackouts due to the intermittency of VRESs has been much less studied.

In this work, we address this question using a model for self-organized criticality in electric power system blackouts, the so-called ORNL-PSERC-Alaska (OPA) model [15]–[18]. In such a model, a constant increase in power demand triggers blackouts due to failures of overloaded power lines or insufficient generation. The engineering response to these failures involves upgrading the capacity of the affected lines and progressively increasing the total generation capacity to keep up with the power demand. In this way, the model brings the power grid continuously to a critical state where random failures may trigger cascading blackouts, and the obtained probability distribution of blackout sizes faithfully reproduces that observed in real power grids, for instance, in the Western Interconnection in North America [19]–[21]. The OPA model can then be used to evaluate the properties and vulnerabilities of electric power transmission grids beyond a usual N-1 criterion. Here, we use the diagnostic capacities of the OPA model to assess the resilience and performance of the power grid with high penetration of VRESs. We focus on two main aspects: the increase in grid stress and possible degradation of its resilience due to an increasing number of blackouts and the VRES performance measured as the fraction of the demand that they cover. To do so, we adapt the OPA model to include photovoltaic and wind power plants with a certain amount of storage, implementing the Balearic Islands power grid for different scenarios with a high ratio of VRESs as a case study. The daily production variability is simulated using random noise with statistical properties similar to those of real VRES data. We find that VRESs lead to two opposite effects. On the one hand, the variability of the power sources increases the stress of the grid. On the other hand, VRES spatial spreading leads to a more evenly distributed generation, decreasing the stress. The combination of these two effects is quantified through the blackout risk, allowing the location of the VRESs to be optimized.

This paper is structured as follows: In Section II, we introduce the OPA model and the modifications that we have made to incorporate VRESs. In Section III, we find the optimal number and location of solar power plants needed to maximize the efficiency and minimize the risk and discuss the benefits of distributed versus localized generation. Next, in Section IV, we analyze the extent to which conventional power plants can be replaced by VRESs, and in Section V, we discuss the implications for the transition to an electric system with high VRES penetration. Finally, in Section VI, we summarize the main findings and offer some concluding remarks.

II. OPA MODEL INCLUDING VRESs

The OPA model represents the loads and generators of an electric grid using a standard DC power flow approximation. 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). A flow chart of the method is displayed in Fig. 1. The fast time scale is indicated in red, while the slow time scale is indicated in blue and green. The part involving renewable energy is indicated in green.

Every day, power is dispatched to cover the demand, giving preference to VRES power plants over conventional plants. All 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 $M_{ij}$ of the power transmitted to the power flow limit reaches the value 0.9. Power is dispatched again and again until no more line failures are produced. The final solution may have some load shed, $L_S$. If the ratio of $L_S$ to the total power demand, $P_D$ is larger than $10^{-3}$, and the event is considered a blackout.

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 $\Delta P_G$ is the difference between the total generation capacity $P_G$ and the power demand $P_D$, normalized to the power demand: $\Delta P_G = (P_G - P_D)/P_D$. The generation capacity is increased every year when its annual average value goes below a predetermined critical value, $\Delta P^c_G$, by upgrading all generators a fixed percentage (4%). In this way, the system copes with the continuous increase in demand. In this work, except for subsection IV-B, we take $\Delta P^c_G = 0.4$.

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. To quantify the effects of VRESs on the stress and resilience of the grid, we use two indicators. First, the overall stress of the power grid is measured by

$$\langle M \rangle = \frac{1}{N} \sum_{i,j} M_{i,j},$$

where $\langle \rangle$ stands for the average over the time duration of a simulation, namely, 100000 days for the cases considered in this work, and $N$ is the number of lines. Second, we use the risk to quantify the resilience of the grid. The risk is calculated as

$$\text{Risk} = A \int \lambda(L_S/P_D)(L_S^2/P_D) dL_S,$$

where $\lambda(L_S/P_D)$ is the probability of having a blackout whose load shed is a fraction $L_S/P_D$ of the total demand [26]. This quantity is a measure of the cost of the blackouts, which is proportional to the lost energy. Assuming that the duration of a blackout is proportional to its relative size, $L_S/P_D$, the lost energy is computed as the power loss, $L_S$, times the duration of the blackout. Because the constant $A$ is difficult to determine, we normalize the risk to the case without VRESs.

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. In our case, we assume that the load shed in node $i$ normalized to its total demand, $L_{S,i}/P_{D,i}$, is proportional to the number of affected customers, so

$$\text{SAIFI} = \sum_{i} N_n \lambda(L_{S,i}/P_{D,i})(L_{S,i}/P_{D,i}),$$

where $\lambda(L_{S,i}/P_{D,i})$ is the probability of having a blackout with load shed $L_{S,i}$ at node $i$, and $N_n$ is the number of consumer nodes. A comparison of these two indexes is shown in Fig. 2 as a function of the fraction of VRESs, $(P_{SG}/P_G)$, for a typical configuration with $n = 10$ solar power plants to be discussed below. One can see that the overall behavior of both indexes as the fraction of VRESs increases is qualitatively similar. Throughout this work, we use risk as a measure of power grid resilience.

### A. BALEARIC ISLANDS ELECTRIC POWER TRANSMISSION NETWORK

We consider a model of the Balearic electric grid that includes the islands Menorca, Mallorca, Ibiza and Formentera (Fig. 3). The grid structure and the location of power plants and substations have been obtained from the website of Red Eléctrica de España [22]. It comprises 62 nodes interconnected by 89 lines. 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.

The daily evolution of the total power demand in the Balearic Islands has been obtained from Red Eléctrica de España [23]. In particular, we consider the daily peak of the demand whose variation along 2014 is shown in Fig. 4 (red symbols). We obtain a smooth annual profile that follows the seasonal variations by fitting a 6th-order polynomial to the data using least squares fitting.

We build a daily synthetic demand for the OPA model using the smooth annual profile with a 0.005% daily increase and the addition of random fluctuations. The random fluctuations
are drawn from a Gaussian distribution with zero mean and variance equal to that of the distribution of distances between actual data and the smooth annual profile. For the spatial distribution of the demand, we use the distribution reported several years ago in [24] scaled to the actual daily peak.

For the Balearic Islands, public information on blackouts is very limited, and we have not been able to obtain information and their cascade propagation from official sources. Therefore, we have estimated the OPA parameter \( p_0 = 0.0001 \text{ days}^{-1} \) by fitting the probability of blackouts larger than 10% of the total demand according to the large blackouts reported in the press in the last ten years. Due to the lack of more detailed historical information, the parameters \( p_1 \) and \( \mu \) have been taken from similar cases in the USA grid [19]. Therefore, throughout this paper, we take \( p_1 = 0.05, \mu = 1.04 \).

### B. VRES Power Plants: Power Fluctuations and Storage

The incorporation of renewable energy plants in the OPA model has been discussed in [25]. This was done for wind generation in northern California. Here, we will follow the same method for solar plants. We base the model on data from a roof-top solar plant on the Consell Insular de Menorca (CIME) headquarters. The data include power production every 15 minutes over nearly three years. Here, we will consider the daily average as well as the daily variability, as shown in red in Fig. 5, for the period of one year.

Solar power is highly variable from day to day; therefore, we assume that solar power plants also have storage capacity to guarantee a constant power supply over a certain period. We consider here that solar power plants aim at delivering a constant level of power each month in a way that an electric company may contract fixed power production during this period. This period of time is arbitrary and can be changed within a certain range without changing the main results to be presented in the following sections. We calculate the power to be delivered, \( P_{\text{out}} \), by maximizing the performance of the solar plant, i.e., making the most of the available solar energy and minimizing storage. If \( P_{\text{in}}(t) \) is the power produced every day and \( P_{\text{out}}(t) \) is the planned power flow out of the plant, we can estimate the energy storage needed to ensure the planned power flow by calculating:

\[
R(t) = \int_0^t [P_{\text{in}}(t') - P_{\text{out}}(t')] dt' \tag{4}
\]

The maximum value of \( R(t) \), \( R_{\text{max}} \), gives us the needed storage. We calculate the power flow out \( P_{\text{out}}(t) \) by minimizing \( R_{\text{max}} \) with the condition \( R(t) > 0 \) for any \( t \). The result for the CIME data is shown in blue in Fig. 5. The value of \( R(t) \), together with \( P_{\text{out}}(t) \), is shown in Fig. 6. In this case, the minimum necessary capacity for storage turns out to be \( R_{\text{max}} = 20.4 \times 10^3 \text{ kWh} \), while the total output over a year is \( \int_0^{365} P_{\text{out}}(t) \ dt \sim 2.2 \times 10^6 \text{ kWh} \). Thus, the storage capacity is equivalent to less than 1% the annual output, or approximately 3.4 days’ worth of average energy production. Taking a smaller storage capacity rapidly increases the probability of undersupply, while considering larger storage does not substantially improve the performance.
The power delivered by a plant we construct a VRES power plant model to be included in the wind power in Section V. We discuss the possibility of including a small fraction of system. Therefore, we do not include them in this study. and, in large numbers, would induce a high risk for the Balearic Islands, wind power plants have low performance because of the large variability of the wind in the location to be a reliable RES.

Next, based on the analysis of the empirical data, we construct a VRES power plant model to be included in the OPA code. The power delivered by a plant \( P_g(t) \) is, whenever possible, equal to \( P_{\text{out}}(t) \). However, depending on the VRES generation, \( P_{\text{in}}(t) \), which we model as a monthly average plus a daily Gaussian random value to simulate daily variations, \( P_g(t) \) takes a value as follows: if \( P_{\text{in}}(t) \) is greater than \( P_{\text{out}}(t) \), then \( P_g(t) = P_{\text{out}}(t) \) and the excess power is accumulated in the storage. If the storage is full, the energy is curtailed. If \( P_{\text{in}}(t) \) is smaller than \( P_{\text{out}}(t) \), power is drawn from storage, if available, and \( P_g(t) = P_{\text{out}}(t) \). In the case that there is not enough stored energy, the delivered power is \( P_g(t) = P_{\text{in}}(t) \).

In this work, we consider that the nominal capacity of a VRES plant is given by the average of \( P_{\text{out}}(t) \) over a year, \( \langle P_{\text{out}}(t) \rangle \). For each plant, the storage capacity is taken as \( R_{\text{max}} = \kappa \langle P_{\text{out}}(t) \rangle \) with \( \kappa = 3.4 \) days. This storage capacity would also be sufficient to cover the day-night cycle variation.

Fig. 8 shows the simulated solar daily production \( P_{\text{in}}(t) \) and the power flow out \( P_{\text{out}}(t) \) for the solar plant model. In the figure, both \( P_{\text{in}}(t) \) and \( P_{\text{out}}(t) \) are normalized to the nominal power, \( \langle P_{\text{out}}(t) \rangle \). The results of this figure can be compared with the real data shown in Fig. 5.

Another question that we face when we incorporate solar plants into the OPA model is the degree of correlation in the sun variability at different locations. Since the Balearic Islands cover a relatively small territory, the correlation is strong for many locations. In this study, we consider two uncorrelated sets of solar plants distributed over the network. Solar plants within each set have fully correlated solar insulation. Similarly, we consider that wind power plants, as discussed in Section V, are distributed in two uncorrelated sets with fully correlated wind fluctuations within each set.

III. LOCALIZED VS DISTRIBUTED GENERATION

In this section, we analyze the effect of the number and location of solar power plants on the overall resilience and performance of the system. This is done by considering scenarios with different numbers \( n \) of solar plants. We define the total solar power \( P_S \) as the sum of the power delivered by the solar plants:

\[
P_S(t) = \sum_{i=1}^{n} P_{g,i}(t). \tag{5}
\]
Similarly, we define the installed solar power $P_{SG}$ as the sum over solar plants of their nominal capacity:

$$P_{SG} = \sum_{i} (P_{out,i}(t)). \tag{6}$$

This definition of the nominal capacity reflects the actual power plants’ average generation capability rather than the peak installed power. For the Balearic Islands, one W of nominal capacity defined in this way corresponds to 6.3 W of installed peak power: $P_{peak} = 6.3 \ P_{SG}$. The ratio of the installed solar power to the total generation capacity $P_{SG}/P_G$ can be considered a measure of the solar energy penetration in the electric sector, and it is used in what follows to characterize different scenarios. Similarly, the performance of VRESs is measured as the fraction of the demand covered by solar plants averaged over the time duration of a simulation, ($P_S(t)/P_D(t)$).

For each scenario with $n$ solar plants, we perform a Monte Carlo-like calculation with solar plants randomly distributed over the grid. We consider 256 runs, each with a different realization of fluctuations and solar plant distribution. Fig. 9 shows the normalized risk versus the performance measured for each realization of scenarios with a different number of power plants. In all scenarios, the installed solar power is 30% of the total generation capacity, $P_{SG}/P_G = 0.3$, and we consider all the solar plants with the same nominal capacity ($P_{out,i}(t) = P_{SG}/n$ for $i = 1, \ldots, n$). Although we have explored many values of $n$, for the sake of simplicity, we include in the figure only the scenarios with 1, 2, 10 and 60 solar plants. We first note that for solar generation concentrated in a single plant (red symbols), the risk is approximately three times that of the case without VRESs; thus, grid resilience is seriously compromised. Furthermore, there is a large variability in the risk (spread along the vertical axis) and in the performance (spread along the horizontal axis). A noticeable decrease in the risk is observed when going from 1 to 2 power plants (blue symbols). The reason is that the two plants are placed one in each set of solar plants with uncorrelated fluctuations. This approach reduces the probability of having a day without enough power generation, thus reducing the risk of blackouts. Furthermore, risk variability and, to a lesser extent, performance variability are reduced. As we further increase the number of solar plants $n$, the risk and its variability continue to decrease up to $n \approx 10$ (orange symbols), beyond which considering a larger number of plants leads to similar results for the risk. Thus, the precise location of the power plants becomes less relevant for grid resilience as we further distribute solar generation beyond 10 power plants. Performance variability also decreases with $n$, but at a slower rate. For $n \geq 60$, solar power plants generate between 27% and 29% of the power regardless of the realization.

This procedure also allows us to optimize the position of VRES power plants. For a given scenario with $n$ solar plants, among all the realizations considered, we can determine the optimal solar plant distribution as the realization with the lowest normalized risk among those with the largest performance ($P_S(t)/P_D$). This optimal distribution of solar plants is used in the remainder of this work. A full optimization analysis including economic factors is beyond the scope of this paper, as we do not intend to provide a specific solution to the problem of integrating high ratios of VRESs but rather to analyze their feasibility and performance in a statistical sense.

Typically, distributed generation decreases the average current in the lines, reducing the needed transmission capacity [27]. This effect can also be noticed here. Increasing $n$ leads to a decrease in the overall stress of the lines as measured by $\langle M \rangle$. Fig. 10 shows the grid stress for the optimal distribution of solar plants with different $n$ values. While
optimal plant distributions for different \( n \) values perform similarly, distributed generation indeed decreases the average current in the lines, as shown in the figure. From \( n = 1 \) to \( n = 40 \), the grid stress decreases by approximately 10%, although for larger \( n \) values, it becomes practically independent of the number of solar plants. The benefits of distributed versus centralized generation are not very pronounced here because the Balearic Islands grid is small. In the cases studied in [26], the effect was stronger because larger networks with a higher level of interconnection were used.

IV. REPLACING CONVENTIONAL GENERATION BY VRESs

In this section, we consider the optimal distribution for a given number of solar plants, and we increase the solar penetration ratio \( P_{SG}/P_G \) from 0 to 1 and analyze the behavior of the system. We first do so considering that the total installed power equals the demand plus a margin, which we maintain at approximately 40% (subsection IV-A). Then, in subsection IV-B, we allow for source redundancy; i.e., a much larger amount of solar generation capacity will be installed. The main issue that we aim to address in both subsections is how far VRES penetration can go while maintaining the performance and risk at reasonable levels.

A. FIXED INSTALLED POWER/DEMAND RATIO

In Fig. 11, we show the fraction of the demand covered by solar power (panel a)) and the risk (panel b)) as a function of the fraction of installed solar power for the optimal distribution with different numbers of solar plants. The fraction of demand covered by solar generation increases almost linearly with the solar installed capacity up to \( P_{SG}/P_G \sim 0.4 \), beyond which the growth is sublinear. The risk normalized to the case without VRESs shows a clear difference between the scenario in which solar generation is concentrated in a single plant and those in which solar generation is distributed among 5 or more plants. The scenario with a single plant always has a higher risk. The reason is twofold. First, a single solar plant cannot benefit from the uncorrelated fluctuations of the two solar sets that we have considered. Second, a very powerful power plant in a single node induces higher stress to some power lines, as shown in Fig. 10. The latter issue is a general drawback associated with any grid configuration in which generation is very localized.

We also observe that when the fraction of solar power increases, the general behavior of the risk is to decrease initially and, for fractions larger than 0.3, to increase exponentially. The initial decrease is due to the benefits of a more distributed generation, while the increase for larger fractions of installed solar power is attributed to the variability of solar irradiation, which precludes guaranteeing the supply under all circumstances when the fraction of solar power is large, inducing blackouts more often. In fact, the increase is exponential due to an exponential increase in the frequency of blackouts. These are not cascading blackouts due to the failure of power lines, but rather are single-step blackouts with a lack of generation. This issue is mainly caused by the low solar generation in winter. Fig. 12 shows the difference in performance between summer and winter for a case with 30% installed solar power generation. The figure plots the distribution of the fraction of the demand covered by solar plants. During the summer months, the distribution peaks at 34%, and for most of the time, solar plants produce more than 30% of the demand. In winter, the probability distribution broadens significantly, and the peak drops to a fraction of the demand at approximately 15%.

Naturally, as the fraction of installed solar power generation increases, the resilience problem becomes more serious, and the lack of power in winter aggravates the situation. Blackouts occur not only in the winter months but also...
in summer because power storage may occasionally be depleted.

B. SOURCE REDUNDANCY

In the previous subsection, we have shown how, due to the inherent variability of the weather, solar power cannot always guarantee the supply. A solution to this problem is installing excess power capacity to be able to supply enough energy, even during periods of low solar irradiation. In this subsection, we explore how increasing the installed power can fulfill the demand in winter. Such installed capacity is clearly excessive in summer, so we consider reduced operation during the summer months. We do so in the following way: we double the solar installed capacity only in the winter months, but use as the nominal power, $P_{\text{nominal}}$, the summer installed capacity. Namely, $P_{\text{nominal}}$ is defined as the average of $P_{\text{out}}(t)$ over a year considering only the capacity installed in summer. The extra installed capacity not used in summer could be partially exported or stored in the form of hydrogen or using other long-term storage technologies, which is a possibility that we do not account for here. If we have twofold more installed solar power in winter than in summer, we obtain a flatter power flow out of the solar plants throughout the year, as shown in Fig. 13. In this figure, $P_{\text{out}}(t)$ is normalized to $P_{\text{nominal}}$. Note that since the nominal capacity is defined considering only summer installed capacity and we are doubling the winter installed capacity, $(P_{\text{out}}(t)) > P_{\text{nominal}}$.

To analyze this situation, we take the optimal solar plant distribution for 10 solar plants (already considered in the previous subsection), double the winter solar installed capacity and consider two different values of the critical generation margin, namely, $\Delta P_{G}^c = 0.4$, which is the value used so far in this work, and $\Delta P_{G}^c = 0.6$. The increase in the critical margin ensures a higher excess power.

In Fig. 14, we summarize the results and compare them with those of Fig. 11 for $n = 10$. We observe that the two new configurations with doubled solar installed power in winter have a slightly better performance so that solar power covers a slightly larger fraction of the demand, particularly for large solar penetration. However, the most important result is the reduced risk. In particular, when we increase the critical margin, we can have a power system operating with a fraction of VRESs above 80% with the same level of risk as with 100% conventional power.

This impressive reduction of the risk comes at a cost. To have double installed solar power in winter and cope with the increased critical margin, it is necessary to have solar installed power that is 2.5-fold the annual average of the power demand, as shown in Fig. 15 (Green line for $P_{SG}/P_G = 0.8$). We discuss the implications of such source redundancy in the next section.

V. DISCUSSION

In 2019, the Balearic Islands consumed a total of 6106 GWh of electric energy, 3506 GWh in the summer months (May–Oct) and 2600 GWh in winter (Nov–Apr). This corresponds to an average power of 697 MW. Only 4% of this energy was produced by RESs on the islands. Thus, 35% of the electricity produced by RESs by 2030 and 100% by 2050 as planned in the The Law of Climate Change and Energetic Transition of the Balearic Islands (LCCiTE) [28] is a serious economic and social challenge. Including the measures to be taken in other energy sectors, this plan aims to reduce greenhouse gas emissions by 40% and 90% in 2030 and 2050, respectively.

Considering a mean annual solar radiation of 1,569 MWh/m² and a 10.8% overall efficiency for the solar plants and taking into account the slope and orientation of the terrain, a surface of approximately 95 km² should be covered by solar panels to produce, on average, the electricity consumed in the Balearic Islands. This area is less than 2% of
FIGURE 14. (a) Fraction of the demand covered by solar power and (b) normalized risk as a function of the fraction of installed solar power for the optimal solar plant distribution with $n = 10$ without source redundancy (red), with doubled installed solar power in winter (blue), and with doubled installed solar power in winter and an increased critical margin (green).

FIGURE 15. Amount of solar power needed to be installed normalized to the annual average demand, $P_{D0}$, for the three cases considered in Fig. 14 as a function of the fraction of installed solar capacity.

the total surface of the islands [2]. Rooftop solar panels alone would have the potential to produce, on average, 57% of the total electricity. In principle, solar photovoltaic technology has the potential to produce several times the electrical energy needs of the Balearic Islands.

This average calculation does not account, however, for the intrinsic variability of solar energy. Also unaccounted for is the storage and the nonvariable generation capacity needed to keep the electric system functioning reliably and uninterruptedly. In particular, to produce on average 100% of the annual energy consumption, the installed peak power (approximately 4400 MWp; 3520 MWp at the AC converter output) would be much larger than the instantaneous consumption at any time (the maximum is approximately 1250 MW in summer). Therefore, storage capacity is needed to properly redistribute the excess production in the moments of maximum solar insulation to the periods of low or null insulation. However, storage in general and battery storage in particular are very expensive and involve very large capacities, such as those allowing energy storage from summer to winter, which are impractical. A proper estimation of the installed VRES power, storage, and backup nonvariable generation needs is imperative for serious planning and reliable operation of the system with high penetration of VRESs.

Our method allows us to estimate the average installed solar power, storage capacity, and conventional/nonvariable power backup needed to keep the system running with a reliability and resilience similar to that of the actual electric system with almost 100% conventional power under different scenarios of VRES penetration. We have addressed the problem of energy supply on a daily time scale. Intraday variability has not been considered, nor has the frequency fluctuations and grid stability at short time scales, from seconds to hours, which would require including the effects of primary and secondary control in conventional power plants. This issue will be addressed elsewhere.

In Section II-B, we estimate the minimum necessary storage $R_{\text{max}}$ needed to compensate for the daily solar variability and keep the power flow out of a solar plant constant over a month. We find that a storage equivalent to less than 1% of the total solar energy produced over a year by the plant is principle enough to use all the available solar power. This storage capacity corresponds to the average production of 3.4 days. Although a few days’ worth of storage may seem reasonable, if scaled up for the whole Balearic Islands consumption, it becomes 57 GWh. For comparison, the largest battery storage projects currently under development have capacities from 0.1 to 1 GWh. Storing 57 GWh of energy would be a challenging problem requiring other technologies in addition to batteries, including pumped storage hydroelectric plants, compressed air, molten salts, hydrogen, etc.
Our model predicts that by replacing conventional generation power with solar power with the abovementioned storage, only a 30% penetration of VRESs can be achieved without increasing the risk too much (Figure 1). 11). The main problem is that with less than 70% of nonvariable generation, the energy supply is not guaranteed in winter months. If VRES generation was sized to produce on average the total annual consumption, the power generation would be much too large in summer and too small in winter, and the storage that we have sized for the monthly production would be insufficient to redistribute the extra summer energy to the winter months.

Without the possibility of storing energy for months, the only solution to cover close to 100% of the demand with renewable energy all year round is sizing the installed solar power to supply enough energy in winter. We have done so by increasing the installed solar power until achieving a system with over 80% VRES penetration, including source redundancy and increasing the critical margin. While this configuration has a low blackout risk, we have had to increase the installed average solar power up to 2.5-fold the average consumption (Figs. 14 and 15). We note that this scenario still has an installed nonvariable power equivalent to 32% (1.6 × 20%, since the capacity margin is 0.6 in this case) of the average power demand. This can be provided by the cable or by nonvariable power plants, which can be either conventional or based on RESs such as biomass or hydrogen produced by excess solar power. In summer months, the large excess energy should be exported to the mainland through the cable, stored in long-term storage facilities to maximize the economic benefit, or possibly curtailed. The present cable has a capacity of 400 MW, which would be less than 5% of the peak power. Assessing the economic viability of this solution is beyond the scope of this work but should be carefully evaluated. The main drawback of solar power in the Balearic Islands is the low average power in winter. Searching for alternative RESs with more availability in winter months would significantly reduce the need for source redundancy.

Finally, although wind energy fluctuates too much to be a reliable source of energy on the Balearic Islands, we have determined whether introducing a small amount, approximately 15% of VRES production, is beneficial for the system. We consider a case with 45% VRES installed power distributed through 62 plants of equal power, namely, one plant in each node of the power grid. As a base case, we take all VRES plants as solar, and we consider scenarios in which a given number of solar plants, randomly chosen, are replaced by wind power plants. We model wind power plants as solar plants in Section II-B but with $P_{th}$ wind instead of solar power (Fig. 7). Fig. 16 shows the risk versus the fraction of the demand covered by VRES generation for 256 realizations of each scenario. The risk is normalized to the base case where all VRES plants are solar (thick black dot). We observe that having up to 20 wind power plants within the 62 VRES plants increases the VRES performance, namely, the fraction of the demand covered by VRES power. The risk is also reduced, being minimum for the case in which wind accounts for 16% of the VRES generation (10 power plants). For more than 20 wind plants out of 62, the risk increases far beyond the range of the figure. The advantage of including a moderate amount of wind energy is that wind fluctuations are in principle uncorrelated with those of the sun and that there is certain complementarity between the availability of wind and sun (Figs. 7 and 8b) [29], reducing the overall energy fluctuations. Wind energy has a much higher potential in mainland locations, so RES power can be imported through the cable, benefiting from this complementarity beyond what we have discussed in this work.

The considered scenarios do not include any management of the demand side. Policies to encourage a reduction in consumption, increase energy efficiency, and use dynamic demand control as effective storage will be crucial to achieve an electric system with a high penetration of RESs in upcoming decades. An economic analysis of a power grid with 80% VRESs would also be needed to complement our feasibility study in terms of the performance and resilience of the system.

VI. CONCLUSION
We have proposed a method to analyze the stress on the grid caused by the massive integration of VRESs and how it affects the risk of blackouts. Using the Balearic Islands as a case study, we have addressed possible scenarios of high VRES penetration and how intermittency affects the resilience and performance of the power grid. Islands are a convenient setup to use this procedure, as they are a suitable framework to test a 100% renewable energy system, and the small-medium size power grid facilitates numerical analysis. The method can also be used, however, to analyze much larger
power grids. In fact, the OPA model has been successfully applied to the Western Interconnection in the USA [19]–[21], and an equivalent analysis is feasible in power grids of this size. Additionally, despite the limited information about the parameters, we would like to stress that the results presented in this work are quite robust to changes, as they have to be interpreted in a statistical way, not for a specific realization of the network.

A high penetration of VRESs has two main consequences: on the one hand, the variability of the power sources increases the stress on the grid, while on the other hand, the spreading of the generation decreases this stress. The combination of these two competing effects has been quantified through the risk, whose minimization allows the location of the VRESs to be optimized. Maintaining the risk below a certain level also allows us to estimate the needed storage and conventional power backup to keep the system running reliably.

We have considered a model for solar power plants that, making use of the least storage possible, takes advantage of as much solar energy as possible, providing constant power over one-month periods. We find that 3.4 days’ worth of energy storage is needed to achieve such performance. Considering VRES power plants with such specifications, we find that up to 30% of conventional power can be efficiently replaced by solar power. Beyond this percentage and keeping the total installed generation capacity equal to the demand plus a 40% margin, the risk of blackouts increases significantly; thus, grid resilience is endangered. One way to overcome this problem is by source redundancy. Doubling the installed power in winter allows us to reach 80% VRES penetration, keeping the risk as low as with full conventional generation. This approach requires, however, a total installed solar generation capacity 2.5-fold larger than the average demand. This scenario still requires an installed nonvariable power equivalent to 32% of the demand. Nonvariable power sources can be either conventional or based on biomass or long-term storage from RESs, as could be done, for instance, using hydrogen as an energy vector. Alternative RESs with more availability in winter would also reduce the need for source redundancy. Indeed, we have also shown that a small amount of wind power, up to 15% of the VRES production, has a positive effect due to the complementarity between sun and wind variability.

We have therefore shown that an electric system can function reliably with a high penetration of VRESs, but with important source redundancy and considerable storage needs. The economic and societal cost of implementing such a system should be analyzed in detail from an interdisciplinary point of view, and in all cases, measures to increase energy efficiency and reduce consumption will be essential to reduce the need for source redundancy.

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