Quantifying the Flexibility by Energy Storage Systems in Distribution Networks with Large-Scale Variable Renewable Energy Sources

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***Abstract*—To counter the intermittent nature of variable Renewable Energy Sources (vRESs), it is necessary to deploy new technologies that increase the flexibility dimension in distribution systems. In this framework, the current work presents an extensive analysis on the level of energy storage systems (ESSs) in order to add flexibility, and handle the intermittent nature of vRES. Moreover, this work provides an operational model to optimally manage a distribution system that encompasses large quantities of vRESs by means of ESSs. The model is of a stochastic mixed integer linear programming (MILP) nature, which uses a linearized AC optimal power flow network model. The standard IEEE 119-bus test system is used as a case study. Generally, numerical results show that ESSs enable a much bigger portion of the final energy consumption to be met by vRES power, generated locally.**

***Index Terms*—Renewable energy sources, distribution systems, energy storage, flexibility.**

I. Nomenclature

A. Sets/Indices

es/Ω^{es}	Index/set of energy storage device
i/Ω^{i}	Index/set of buses
$g/\Omega^{g}/\Omega^{vRES}$	Index/set of generators/vRES
k/Ω^{k}	Index/set of branches
$hh, h/\Omega^{h}$	Index/set of hourly snapshots
s/Ω^{s}	Index/set of scenarios
$\varsigma/\Omega^{\varsigma}$	Index/set of substations

B. Parameters

$E_{es,i}^{min}, E_{es,i}^{max}$	Minimum and maximum energy storage limits, respectively (MWh)
$ER_{g}, ER_{\varsigma}^{SS}$	Emission rates of vRES/generators, and imported energy from upstream, respectively (tCO_2e/MWh)
g_k, b_k, S_k^{max}	Conductance, susceptance and flow limit of line k (Ω, Ω, MVA)
MP_k, MQ_k	Big-M parameters related to branch k
$OC_{g,i,s,h}$	Unit cost of energy production (€/MWh)
N_i, N_{ς}	Total number of buses and substations
$P_{es,i}^{ch,max}, P_{es,i}^{dch,max}$	Charging and discharging power limits (MW)
V_{nom}	Nominal voltage (kV)
Z_{ij}, R_k, X_k	Impedance, resistance and reactance of line i-j (Ω)
$\lambda_{s,h}^{CO_2e}$	Emissions price (€/tons of CO_2 equivalent)
$\lambda_{s,h}^{\varsigma}$	Electricity price of imported energy (€/MWh)
$\lambda_{es,i,s,h}^{dch}$	Energy cost of storage system device (€/MWh)
$\eta_{es}^{ch}, \eta_{es}^{dch}$	Efficiency of charging and discharging (%)
ρ_s, π_w	Probability of scenario s and weight associated with operational snapshot w
$\upsilon_{s,h}$	Unserved power penalty (€/MW, €/MVAr)

C. Variables

$PD_{s,h}^{i}, QD_{s,h}^{i}$	Active demand and reactive demand at node i (MW, MVAr)
$E_{es,i,s,h}$	Reservoir level of energy storage device (MWh)
$I_{es,i,s,h}^{dch}, I_{es,i,s,h}^{ch}$	Discharging and charging binary variables
$P_{g,i,s,h}, Q_{g,i,s,h}$	Active and reactive power that are produced by vRES (MW, MVAr)
$P_{\varsigma,s,h}^{SS}, Q_{\varsigma,s,h}^{SS}$	Active and reactive power imported from upstream (MW, MVAr)
P_k, Q_k, θ_k	Active, reactive power flow, voltage angle difference of line k (MW, MVAr, radians)
PL_k, QL_k	Active power losses and reactive power losses in line k (MW, MVAr)
$PL_{\varsigma,s,h}, QL_{\varsigma,s,h}$	Active power losses and reactive power losses at substation ς (MW, MVAr)
$P_{es,i,s,h}^{dch}, P_{es,i,s,h}^{ch}$	Discharged and charged power by energy storage devices (MW)
$P_{i,s,h}^{NS}$	Unserved power at bus i (MW)
$Q_{i,s,h}^{NS}$	Unserved power at node i (MW)
V_i, V_j	Voltage magnitudes at bus i and bus j (kV)
$u_{k,h}$	Utilization variable of a line
θ_i, θ_j	Voltage angles at bus i and bus j (radians)

D. Functions

EC_h^{SS}	Expected cost of imported power (€/h)
EC_h^{vRES}	Expected cost of energy associated to vRES power production (€/h)
EC_h^{ES}	Expected cost of energy associated to energy supplied by storage devices (€/h)

$ENSC_h$	Expected cost of unserved power (€/h)
$EmiC_h^{vRES}$	Expected emission cost associated to vRES power production (€/h)
$EmiC_h^{SS}$	Expected emission cost of imported power (€/h)

II. Introduction

A. Aims and Motivation

Integration of variable renewable energy sources (vRES) is likely to grow even more because of multi-faceted needs. For example, there is an increasing trend of demand for electricity, extreme urgency to reduce the profound reliance on fossil fuels for power production and hence emissions, and energy security, among others. Intermittent energy technologies, such as wind and solar PV, are projected to reduce 80% to 90% of greenhouse gas (GHG) emissions by the year 2050 [1].

A well-known challenge about these technologies is their dependence on weather conditions, i.e. solar irradiation, wind speed, and the fact that there is no homogeneity of these primary energy sources in one given area.

If the integration of vRES into systems is done in a well-designed and coordinated way, this can bring several benefits, in particular in reducing or delaying some investments in the grid, improving efficiency, reducing dependence on fossil fuels for energy production, and consequently decreasing GHG releases [2]. Because of the various arguments presented above, the future power grid has to integrate the technologies and tools needed to accommodate an increasing amount of vRES.

The current tendencies demonstrate that the integration and use of vRES in a power system, especially wind and photovoltaic, is increasing despite several barriers. However, the non-predictable nature of wind and solar implies that extensive integration of these technologies is likely to create technical issues especially in distribution systems.

System operators (at distribution and transmission levels) are concerned because traditional means of managing power systems are becoming insufficient for maintaining a stable and reliable operation of electrical systems.

To counter the partially unpredictability of resources like wind and solar irradiation, brand new management mechanisms and tools need to be deployed in the systems. Basically, it means that new ways should be sought that increase the flexibility of systems that counterbalance the continuous fluctuations induced by vRES power production, as well as traditional fluctuations in demand [3], [4].

Customarily, the balance between demand and generation is held by conventional power plants. With a higher penetration level of vRES, this method can be excessively expensive or insufficient. A higher standard of flexibility is needed to ensure system reliability.

Hence, new emerging flexibility options can be thought to manage instantaneous imbalances in energy production and demand, securing stability, electric supply and power quality of the electric system.

Such flexibility opportunities can be obtained, for example, through the installation and coordination of different technologies such as energy storage systems (ESSs), demand response (DR) and switching capacitor banks.

These flexibility options can achieve reliable and efficient power systems, reduce GHG emissions and ensure affordability of energy for end users. The benefits from these technologies are the enhancement of the total system flexibility, which can impact the ability of the system to continuously sustain an ordinary service when facing bulky fluctuations in the generation and demand [5], [6].

The integration and operation of vRES to meet the electricity demand encompasses appropriate flexibility options in order to balance the imminent fluctuations [7].

B. Literature Review

The existing literature includes some recent works carried out to understand the impacts on the terms of operation of distribution systems by adding ESSs and vRESs.

Authors in [8] propose a genetic algorithm to solve a model based on a bi-level programming considering the allocation and operation of ESSs at the same time.

Authors in [9] present a model based on mixed integer linear programming (MILP) for an optimal scheduling of ESS operations by coordinating the delivery of various system services, and then being remunerated at different market prices.

Ref. [10] proposes an optimal energy management of ESSs in micro-grids via a dynamic programming approach. The stored energy is used to match the imbalance of loads and renewable energies.

The work in [11] presents a detailed analysis of future distribution systems integrating vRESs and ESSs.

In [12], authors have developed an optimal sizing of wind energy in coordination with storage sources based on stochastic models of historical wind speed profiles as well as load. The objective function is the minimization of investments and annual operation costs of the vRESs and ESSs, which is then solved by a self-adapted evolutionary strategy.

In [13], a dynamic optimization model is developed to account for the impact of the present cost schemes on a system with mixed generation for heat and electricity loads, jointly with storage units.

Authors in [14] present a dynamic programming approach considering the limitations in the operation of ESSs and losses of a distribution system.

A similar work [15] reports on distribution system analysis regarding technical and economic impacts of distributed generation (DG) integration and ESSs.

C. Contributions and Paper Organization

In this paper, a stochastic mathematical optimization model is developed to optimally manage distribution systems.

The novel contributions are twofold:

- An extensive analysis regarding the flexibility delivered by ESSs and their impact on the vRESs penetration level is conducted. The analysis is carried out both from economical and technical perspective.
- Moreover, this work investigates the impacts of the high integration level of vRES power on the global performance of distribution systems in terms of voltage profiles, total active and reactive power losses, total costs, system stability and reliability, in a holistic view.

III. Mathematical Formulation

A. Objective Function

The objective function corresponds to the minimization of costs, including operation cots and the costs associated to emissions and unserved power.

$$Minimize\ TC = TEC + TENSC + TEmiC \tag{1}$$

where TC means total cost of operation.

In (1), TEC models expected costs associated to wind and solar technologies power production, importing energy from transmission grid and operating ESSs. Each term is calculated as follows:

$$EC^{vRES} = \sum_{s\in\Omega^s}\rho_s \sum_{h\in\Omega^h}\sum_{g\in\Omega^g} OC_g P^{vRES}_{g,i,s,h} \tag{2}$$

$$EC^{ES} = \sum_{s\in\Omega^s}\rho_s \sum_{h\in\Omega^h}\sum_{es\in\Omega^{es}} \lambda^{es} P^{dch}_{es,i,s,h} \tag{3}$$

$$EC^{SS} = \sum_{s\in\Omega^s}\rho_s \sum_{h\in\Omega^h}\sum_{\varsigma\in\Omega^\varsigma} \lambda^{\varsigma}_h P^{SS}_{\varsigma,s,h} \tag{4}$$

The calculation is made according to the sum of active and reactive power that is not served.

$$TENSC = \sum_{s\in\Omega^s}\rho_s \sum_{h\in\Omega^h}\sum_{n\in\Omega^n} (\upsilon^P_{s,h} P^{NS}_{i,s,h} + \upsilon^Q_{s,h} Q^{NS}_{i,s,h}) \tag{5}$$

The penalty parameters are $\upsilon^P_{s,h}$ and $\upsilon^Q_{s,h}$ that correspond to active power demand and reactive power demand deprived.

Finally, the last term, $TEmiC$, is accountable for the system emissions cost. It is the outcome of generating power using vRES and upstream importation of energy.

$$TEmiC = EmiC^{vRES} + EmiC^{SS} \tag{6}$$

where:

$$EmiC^{vRES} = \sum_{s\in\Omega^s}\rho_s \sum_{h\in\Omega^h}\sum_{g\in\Omega^g}\sum_{n\in\Omega^n} \lambda^{CO_2} ER^{DG}_g P^{DG}_{g,i,s,h} \tag{7}$$

$$EmiC^{SS} = \sum_{s\in\Omega^s}\rho_s \sum_{h\in\Omega^h}\sum_{\varsigma\in\Omega^\varsigma}\sum_{n\in\Omega^n} \lambda^{CO_2} ER^{SS}_\varsigma P^{SS}_{\varsigma,s,h} \tag{8}$$

B. Constraints

The first constraint is related to Kirchhoff's current law, which is used as follows to active and reactive power flows:

$$\begin{aligned}\sum_{g\in\Omega^g} P^{vRES}_{g,i,s,h} + \sum_{es\in\Omega^{es}} \left(P^{dch}_{es,i,s,h} - P^{ch}_{es,i,s,h}\right) + P^{SS}_{\varsigma,s,h} + P^{NS}_{i,s,h} \\ + \sum_{in,l\in\Omega^l} P_{l,s,h} - \sum_{out,l\in\Omega^l} P_{l,s,h} \\ = PD^i_{s,h} + \sum_{in,l\in\Omega^l} \frac{1}{2} PL_{l,s,h} \\ + \sum_{out,l\in\Omega^l} \frac{1}{2} PL_{l,s,h}\ ; \forall\varsigma\epsilon\Omega^\varsigma;\ \forall\varsigma\epsilon i; l\epsilon i\end{aligned} \tag{9}$$

$$\begin{aligned}\sum_{g\in\Omega^g} Q^{vRES}_{g,i,s,h} + Q^{SS}_{\varsigma,s,h} + Q^{NS}_{i,s,h} + \sum_{in,l\in\Omega^l} Q_{l,s,h} - \sum_{out,l\in\Omega^l} Q_{l,s,h} \\ = \sum_{in,l\in\Omega^l} \frac{1}{2} QL_{l,s,h} + \sum_{out,l\in\Omega^l} \frac{1}{2} QL_{l,s,h} \\ + QD^i_{s,h}\ ; \forall\varsigma\epsilon\Omega^\varsigma;\ \forall\varsigma\epsilon i; l\epsilon i\end{aligned} \tag{10}$$

The other constraint is linked to the Kirchhoff's voltage law. Two approximations may be considered: bus voltage magnitudes close to nominal value V_{nom}, and very small voltage angle difference θ_k leading to $\sin\theta_k \approx \theta_k$ and $\cos\theta_k \approx 1$.

With the previous assumptions, it is possible to linearize AC power flow equations, taking away non-linearities and non-convexities.

$$MP_k(u_{k,h}-1) \leq P_{k,s,h} - V_{nom}(\Delta V_{i,s,h} - \Delta V_{j,s,h})g_k + V_{nom}^2 b_k \theta_{k,s,h} \leq MP_k(1-u_{k,h}) \tag{11}$$

$$MQ_k(u_{k,h}-1) \leq Q_{k,s,h} + V_{nom}(\Delta V_{i,s,h} - \Delta V_{j,s,h})b_k + V_{nom}^2 g_k \theta_{k,s,h} \leq MQ_k(1-u_{k,h}) \tag{12}$$

$$\Delta V^{min} \leq \Delta V_{i,s,h} \leq \Delta V^{max} \tag{13}$$

Equations (11) and (12) include the state of the branch $u_{k,h}$ (1 if connected and 0 if disconnected).

The maximum transfer capacity is the upper bound of the power flow in every line, as imposed by (14).

$$P_{k,s,h}^2 + Q_{k,s,h}^2 \leq u_{k,h}(S_k^{max})^2 \tag{14}$$

Active and reactive power losses can be estimated as quadratic functions, as in (15) and (16).

$$PL_{k,s,h} = R_k \left(P_{k,s,h}^2 + Q_{k,s,h}^2\right) / V_{nom}^2 \tag{15}$$

$$QL_{k,s,h} = X_k \left(P_{k,s,h}^2 + Q_{k,s,h}^2\right) / V_{nom}^2 \tag{16}$$

The ESSs charged/discharged power is constrained according to (17) and (18):

$$0 \leq P_{es,i,s,h}^{ch} \leq I_{es,i,s,h}^{ch} P_{es,i,h}^{ch,max} \tag{17}$$

$$0 \leq P_{es,i,s,h}^{dch} \leq I_{es,i,s,h}^{dch} P_{es,i}^{ch,max} \tag{18}$$

ESSs are not charged and discharged at the same time, as enforced by (19).

$$I_{es,i,s,h}^{ch} + I_{es,i,s,h}^{dch} \leq 1 \tag{19}$$

The balance equation is provided hereafter in the following equation.

$$E_{es,i,s,h} = E_{es,i,s,h-1} + \eta_{es}^{ch} P_{es,i,s,h}^{ch} - P_{es,i,s,h}^{dch} / \eta_{es}^{dch} \tag{20}$$

Storage level should be within maximum and minimum capacity.

$$E_{es,i}^{min} \leq E_{es,i,s,h} \leq E_{es,i}^{max} \tag{21}$$

The initial and final storage levels also need to be set according to (22).

$$E_{es,i,s,h0} = \mu_{es} E_{es,i}^{max}; \; E_{es,i,s,h24} = \mu_{es} E_{es,i}^{max} \tag{22}$$

Active and reactive power production bounds of vRES are also imposed with the following constraints.

$$P_{g,i,s,h}^{vRES,min} \leq P_{g,i,s,h}^{vRES} \leq P_{g,i,s,h}^{vRES,max} \tag{23}$$

$$-tan\left(cos^{-1}(pf_g)\right) P_{g,i,s,h}^{vRES} \leq Q_{g,i,s,h}^{vRES} \leq tan\left(cos^{-1}(pf_g)\right) P_{g,i,s,h}^{vRES} \tag{24}$$

The reactive power substation is also associated to constraints.

$$-\tan\left(cos^{-1}(pf_{ss})\right) P_{\varsigma,s,h}^{SS} \leq Q_{\varsigma,s,h}^{SS} \leq \tan\left(cos^{-1}(pf_{ss})\right) P_{\varsigma,s,h}^{SS} \tag{25}$$

The radiality constraints, as in [16], are also incorporated into the model.

IV. Case Study, Results and Discussions

A. Data and Assumptions

In this paper, the large-scale IEEE 119-bus distribution system is take into account as a case study. This system has a nominal voltage, active and reactive power demand of 11 kV, 22709.72 kW and 17041.07 kVAr, respectively [17]. The sizes and locations of vRES and ESSs are also taken from [17].

The operational analysis is for a period of 24-hour. The maximum admissible variation of voltage at each bus is ±5% of nominal value (11 kV).

The substation has a power factor set to 0.8; whereas, the power factor of vRES power generators is 0.95.

Importing power through the substation is assumed to incur emission costs, with an average emission rate set to $0.4\ \mathrm{tCO_2e/MWh}$.

Solar and wind power generators have emission rates of 0.0584 and $0.0276\ \mathrm{tCO_2e/MWh}$. Emissions have a price set to $7\ €/\mathrm{tCO_2e}$. The unit tariffs of wind and solar power generation correspond to 20 and $40\ €/\mathrm{MWh}$. ESSs charging and discharging efficiencies are considered to be 90%. Variable cost for ESS operation is $5\ €/\mathrm{MWh}$.

Cost of unserved power is $3000\ €/\mathrm{unit}$, for both active and reactive power. Both big-M parameters are considered equal to 30.

The number of partitions considered in the linearization of quadratic flow terms is 5 (for more information and justifications, see in [18]).

The uncertainty is addresses with scenarios for demand, wind and solar power. The combination of the individual scenarios is 81.

It is worth mentioning here that our analysis is based on a stochastic optimization framework.

B. Discussion of Numerical Results

To guide the analysis performed in this work, three different cases are considered. The first one, designated as "Base Case", denotes the system in which no DGs and ESSs are integrated.

In this particular case, lower voltage bounds are relaxed; otherwise, there would be a large amount of unserved power, particularly in farthest nodes of the system.

The second case, designated as "Without ESS", considers optimally placed vRES-type DGs in the system. The third and last case, referred to hereinafter as "With ESS", assumes that, in addition to DGs, ESSs are optimally and strategically placed in the system. Both cases see the same type, location and amount of DGs integrated in the considered system. Moreover, the upper and lower voltage limits are imposed in the both cases.

In Table I, the total expected cost in the system and its components as well as the total expected power losses are summarized.

In the "Without ESS" case, which considers DGs in the network, the total expected cost is reduced by about 42.5% taking the Base Case as a reference, and this happens because producing power locally is more economic than importing power.

The imported power from the upstream grid is slashed out, which effectively leads to lower emission cost (by about 57.7%). When comparing the first and second cases, the expected cost of involuntary load shedding is lower in the second case (i.e. the Without ESS case) than in the Base Case.

This is attributed to the fact that, when DG is added into the system, some active technical constraints that would otherwise lead to load shedding are relieved, overall lowering the expected unserved power. In terms of expected costs of unserved power, a reduction of 77.9% can be observed in Table I.

For the third case (i.e. "With ESS"), the results in Table I show that the total energy cost is reduced by more than half (52.9%) compared to the Base Case. Generally, the joint allocation of DGs and ESSs in distribution systems leads to a significant reduction in the cost of energy, unserved power, losses and emissions (see Table I).

Compared to the Base Case, the expected emission costs (*TEmiC*) are decreased by about 70.8%. Also, as can be inferred from Table I, there is no unserved power, simultaneously featuring DGs and ESSs.

Combined operation of DGs and ESSs can better utilize any "excess" of renewable power production by storing it in the ESSs. Thus, ESSs can increase the system flexibility, allowing an efficient utilization of power production using intermittent power sources, for example wind and solar, as in this case.

The reduction in the aggregate network losses is also dramatic in the cases where DGs and ESSs are considered. In fact, in the Base Case, the total expected active and reactive power losses are 20.25 MW and 14.105 MVAr; whereas, in the second case, these amount to only 7.45 MW and 6.35 MVAr, respectively.

In the third case, these are further reduced to 4.95 MW and 4.19 MVAr, respectively. Taking the losses in the Base Case as baseline, the net reductions in the losses related to the "With ESS" case are approximately 69% and 70%, respectively.

TABLE I. A break-down of costs for the different cases and aggregate network losses.

	Base Case	**Without ESS**	**With ESS**
TC (€)	32217.38	18101.81	14637.50
TEC (€)	30349.82	17442.59	14281.01
TEmiC (€)	1219.56	516.20	356.50
TENSC (€)	647.99	143.02	0.00
Total active power losses (MW/day)	20.25	7.45	6.35
Total reactive power losses (MVAr/day)	14.11	4.95	4.19

Another important point in the system performance is the voltage profile analysis. Theoretically, for the system to have a good performance, the voltage deviation must stay as close to the nominal value as possible.

However, the voltages at the nodes are generally permitted to vary within a certain range, which in our case is from -5% and +5%.

Thus, in Figure 1, it can be clearly seen that the presence of flexibility options, i.e. ESS, leads to considerably improved voltage profile in the system, keeping the voltages well within operating limits.

Figure 2 shows the aggregate energy mix profile for the 24 hours system operation period related to the case where ESS are not considered (i.e. "Without ESS"). In the same figure, we can observe that the PV and wind type DG, optimally placed throughout the system, bring some system flexibility.

Hence, the percentage of aggregate energy consumption throughout the day that is covered by the DG amounts to 61% (which breaks down to 57% by wind and 4% by solar PV).

This means that the majority of the demand is met by the locally generated power. Note that the demand curves (distinguished by "Residential" and "Industrial" in Figure 2) represent stacked plots.

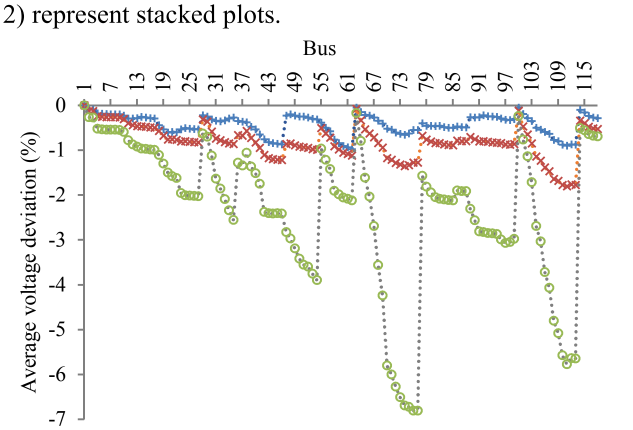

Figure 1. Average voltage profiles for the three different cases (-+- with ESS, -x- without ESS and -o- base case).

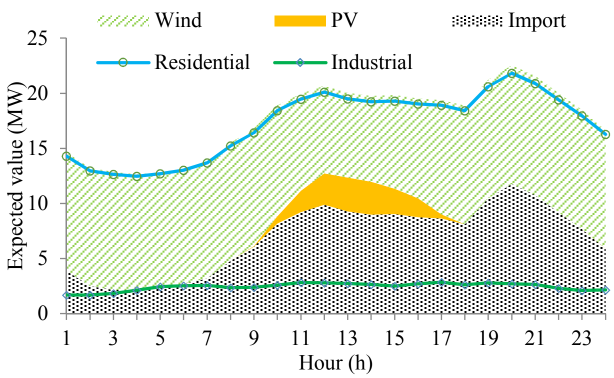

Figure 2. Energy mix profile without ESSs.

V. CONCLUSIONS

This paper has analyzed the ESS contribution in terms of adding flexibility to distribution systems, which then enables such systems to manage the intermittent vRES nature. To accomplish the analysis, a stochastic MILP operational model is employed. The main objective of the study is to frame a least-cost operation of distribution systems featuring large quantities of vRES type DGs and ESSs while respecting all constraints. The stochastic model is built on a linearized AC optimal power flow. According to the numerical results, the deployment of DGs in conjunction with ESSs results in a more effective use of renewable power, which is locally produced. Generally, results highlight the added flexibility provided by ESSs, enabling enhanced management of vRES intermittency.

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