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Economic viability for residential battery storage systems in grid-connected PV plants

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Abstract: Today's residential battery energy storage systems (BESSs) are off the shelf products used to increase the self-consumption of residential photovoltaic (PV) plants and to reduce the losses related to energy transfer in distribution grids. This work investigates the economic viability of adding a BESS to a residential grid-connected PV plant by using a methodology for optimising the size of the BESS. The identification of the optimal size which minimises the total cost of the system is not trivial; indeed, it is a trade-off between OPEX and CAPEX, which are mainly affected by the battery technology, usage profile, expected lifetime, and efficiency. Here, an analysis of the opportunity to install a storage system together with a grid-connected residential PV plant is performed. Three typical low-voltage prosumers (Italy, Switzerland, and the UK) are investigated in order to take into account the different legislative and tariff framework over Europe. Numerical results reported here show that present costs of storages are still too high to allow an economic convenience of the storage installation. Moreover, an indication of the necessary incentives to allow the spreading of these systems is given.

Nomenclature

α	$(1+c_r)/(1+d_r)$
η_B	efficiency of battery pack
η_I	efficiency of the inverter
η_{PV}	efficiency of the PV
a_b	battery actualising term
a_g	grid actualising term
A_h	actual battery pack capacity (Ah)
A_{ho}	initial battery pack capacity (Ah)
BL	battery lifetime (years)
$C_{battery}$	total battery cost (€)
c_{buy}	purchase energy grid cost (€)
C_g	annual fixed cost of the electrical service provider (€)
C_{grid}	total grid cost (€)
c_i	incentives (€)
c_{ins}	battery installation and disposal specific costs (€/kg)
C_{ins_fix}	battery installation and disposal fixed costs (€)
C_{INV}^a	actualised battery inverter cost (€)
$c_{int,battery}$	specific intrinsic battery cost (€)
C_{INV}	battery inverter cost (€)
$C_{ins\_fix}^a$	actualised battery installation and disposal fixed costs (€)
c_r	capital cost rate
c_{sell}	sale energy grid cost (€)
$c_{sto,battery}$	unitary cost of the stored energy in the battery (€)
$c_{sto,grid}$	unitary cost of the stored energy in the grid (€)
C_{tot}	total cost (€)
c_W	specific battery cost (€/Wh)
c_W^{th}	specific battery cost threshold (€/Wh)
DoD	depth of discharge
d_r	discount rate
E_{buy}	annual energy bought from the grid (kWh)
EoL	battery end of life
E_s	specific energy of the battery pack (Wh/kg)
E_{sell}	annual energy sold from the grid (kWh)
E_{sold}	energy sold to the grid over the plant life (kWh)
E_{stored}	energy exchanged with the battery or with the grid over the plant life (kWh)
E_{TOT}	total energy exchanged by the battery over its life (kWh)
g_c	capacity ageing coefficient
g_r	resistance ageing coefficient
I	battery current (A)
K_M	maintenance coefficient of the battery pack
m	mass of the battery pack (kg)
N_c	life cycle of the battery pack
N_{isn}	number of battery pack installations
P_B	power exchanged by the battery pack (kW)
P_{grid}	power exchanged with the grid (kW)
PL	plant lifetime (years)
P_{LOAD}	power absorbed by the domestic load (kW)
P_{PV}	power generated by the PV (kW)
P_{sold}	power related to the energy sold to the grid (kW)
P_{stored}	power related to the energy stored in the battery or in the grid (kW)
q	actual moved charge by the battery (Ah)
Q_{TOT}	total charge moved by the battery over its life (Ah)
R_0	initial internal battery resistance (Ω)
R_{in}	actual internal battery resistance (Ω)
S	PV surface (m^2)
SoC	state of charge
SoC_i	initial state of charge
SoH	state of health
V	battery voltage (V)
V_n	nominal voltage of the battery pack (V)
V_o	no-load battery voltage (V)

1 Introduction

The declining cost of photovoltaic (PV) solar modules is driving the deployment of PV systems worldwide. In total, >75 GW peak power of PV were installed in 2016 in the international energy agency PV power system programme (IEA PVPS) countries [1]. Based on data in between 1976 and 2016, the learning curve of the PV module is 22.5% and, considering different insolation

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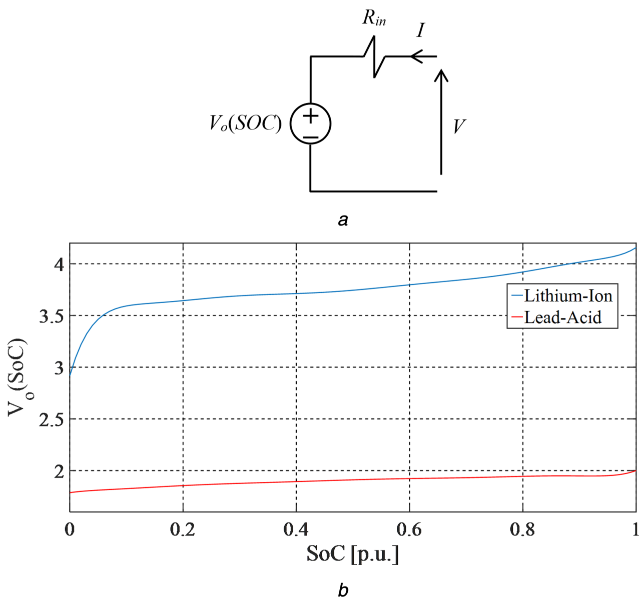

Fig. 1 *Battery modelling*
(a) Electric circuit model, ***(b)*** Battery terminal voltage as a function of SoC for lithium-ion and lead-acid batteries

conditions, today's levelised cost of electricity (LCOE) is in a range of 0.4 or 0.8 USD/kWh [2].

Battery energy storage systems (BESSs) are one of the most promising solutions for reducing the intermittence of PV systems; BESSs (i) increase the percentage of self-consumed electricity up to 70% [3], (ii) increase the PV penetration in our electric grids [4, 5], and (iii) guarantee an adequate power quality level in distribution grids [6].

The total utility scale grid-connected BESS market was 0.48 GW in 2014, and it is set to reach up to 12 GW by 2024, while annual revenues will grow to around 8.44 billion USD [7]. The experience curve for lithium ion batteries in electric vehicle applications is 21%, which is very close to that one of the PV market [8]. Levelised costs of storage (LCOS) for electrochemical storage systems are in the range of 0.338 (redox-flow) to 3.072 (lead-acid) USD/kWh [9]. LCOS is defined as the total cost of ownership over the investment period (that is the sum of the purchase cost of the storage system plus all the costs of maintenance and of electric energy required for charging) divided by the delivered energy.

Despite the continuing market expansion, investments in BESSs present a high financial risk dealing with the evaluation of performances in real operation. Optimal sizing methodologies have been addressed in [10–14]. However, they are focused only on the economic aspects considering the battery pack attains the nominal performances for all its lifetime and in all operative conditions.

The expected lifetime of a battery depends on many factors, including temperature, current cycle, and depth of discharge (DoD). The nominal data provided by manufacturers, which refer to standard and fixed working conditions, are insufficient for a proper system design.

Complex models are available in the literature to take into account the battery dynamic [15–20], thermal behaviour [21–23], and ageing aspects [24–31]. An *ad hoc* methodology for a correct battery system sizing is required. The authors in [32] have already addressed a methodology for a correct sizing of electrochemical storage systems; the integrated model estimates the battery performances as expected lifetime, efficiency, and energy and power densities on the basis of the real power profile usage and operative working conditions. In [33], the authors used the proposed technical procedure to size the capacity of the BESS in a stand-alone PV plant, and the results are compared with those ones obtained by using the procedures described in the IEEE 1013 and 1561 standards [34, 35]. The procedure in [33] is limited to stand-alone systems and it cannot be used for grid-connected PV integrating a battery storage system.

In this paper, we investigate the economic viability of battery storage for residential solar PV systems operating grid connected. The technical procedure for the battery sizing is integral part of the economic analysis, so that the financial figures are provided taking into account the impact of battery operations on the real system performances.

In the analysis, three different user cases corresponding to different countries over Europe are considered: Italy, Switzerland, and the UK. The investigation takes into account two different battery technologies (lithium-ion and lead acid), and the actual prices of electricity.

The work is organised as follows: in Section 2, the equivalent model of the battery is provided and it is integrated in the cost analysis procedure described in Section 3. In Section 4, the three selected case studies are presented and in Section 5, the simulation results are reported and discussed. Finally, the conclusions come in the end of the paper in Section 6.

2 Battery modelling

The main battery models can be organised under three different categories: electric, thermal, and ageing models. In [32], a general model that interconnected three previous ones was proposed. This made it possible to separately characterise the electric, thermal, and ageing phenomena. The complete behaviour of a certain battery was then obtained by joining them together, where each of those models was chosen on the basis of what has to be characterised.

The aim of the present paper is to extend the analysis made in [33] to the case of a residential grid-connected PV plant equipped with a BESS over a time horizon of 20 years, taking into account, in particular, the ageing of the batteries during these years, and neglecting the temperature effects.

Since we are interested to simulate the battery behaviour over a long period, the electric model can be simple, without paying attention to the dynamic effects of the battery. The simplest one is constituted by an ideal voltage source V_o as a function of the SoC series to an internal resistance R_{in} (Fig. 1*a*). This electric model is not able to represent the dynamic effects of the battery. Rather, it is only suitable to represent the steady-state behaviour. The V_o(SoC) functions for both a lithium ion cell and lead-acid cell are reported in Fig. 1*b*.

The resistance R_{in} is calculated taking into account the efficiency of the battery pack as follows:

$$R_{\text{in}} = \frac{E_s m(1-\eta_B)}{A_{\text{ho}} I(A_{\text{ho}})(1+\eta_B)} \tag{1}$$

where $E_s m$ is the sizing energy; η_B is the efficiency of the battery pack; and $I(A_{\text{h0}})$ is the current, which has the same value as the initial capacity A_{h0}. The equivalent electric circuit is described by the following equations:

$$\begin{gathered} V = V_o(\text{SoC}) + R_{\text{in}} I \\ \text{SoC} = \int I \mathrm{d}t + \text{SoC}_i \\ 0 \le \text{SoC} \le A_h\,. \end{gathered} \tag{2}$$

Under the hypothesis that batteries work in a small range of temperatures, the thermal behaviour can be neglected. Therefore, the thermal model is not included in the general one.

Finally, the ageing model chosen is the one proposed in [29], according to which the ageing of the battery is due to the square root of the total moved charge. Actually, it is well known that the ageing of batteries is due to the cycle ageing and the calendar effect. In [29], the ageing is a function of the square root of the moved charge, cycling and calendar effects are jointly taken into account: the total charge is moved over time. In [31], the proposed calendar ageing model depends on the square root of the time at a certain temperature. Fixed the temperature, we can assume that the moved charge depends on the average current along the time. In this way, both phenomena have the same dependency on the time.

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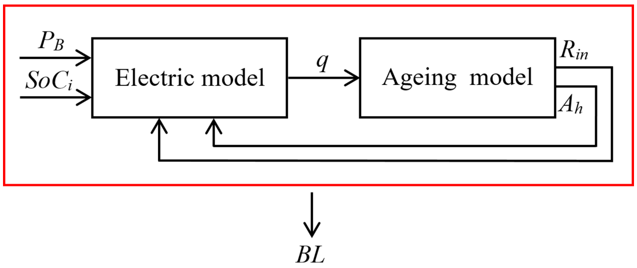

Fig. 2 *Integrated model*

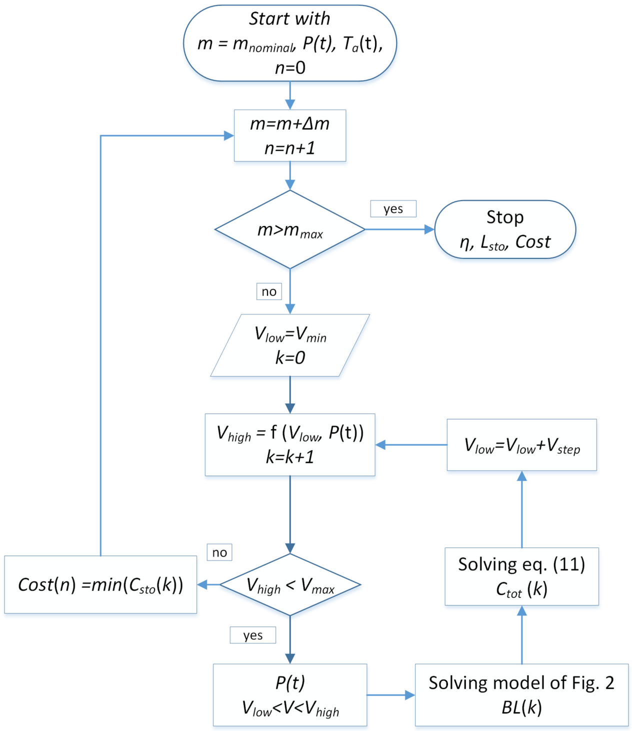

Fig. 3 *Flow diagram for correct sizing of the storage system [32]*

Consequently, the model proposed in [29] can be used for the total ageing. The indicator of the state of health (SoH) is the reduction in the initial capacity of the battery A_{ho}, and it can be expressed as a function of the total moved charge q (Ah) as follows:

$$\text{SOH} = \frac{A_{\text{h}}}{A_{\text{ho}}} = 1 - g_{\text{c}}\sqrt{q} \tag{3}$$

where A_{h} is the actual capacity and g_{c} is the capacity ageing coefficients, which depend on the type of battery. This coefficient is calculated by taking into account the life cycles N_{c} at a certain DoD and along a certain time period, given by the battery manufacturer, and the end of life (EoL), typically, when the actual capacity decreases to 80% of the initial one:

$$g_{\text{c}} = \frac{0.2}{\sqrt{2\text{DoD} \cdot A_{\text{ho}} \cdot N_{\text{c}}}}. \tag{4}$$

The actual capacitance as a function of the moved charge is obtained by multiplying (3) by A_{h0}

$$A_{\text{h}}(q) = A_{\text{ho}} - g_{\text{c}}A_{\text{ho}}\sqrt{q}\,. \tag{5}$$

In addition, the resistance R_{in} changes during the ageing process. According to [28], the series resistance varies with the square root of the moved charge:

$$R_{\text{in}}(q) = R_0 + g_{\text{r}}R_0\sqrt{q} \tag{6}$$

where R_0 is the initial resistance, and g_{r} is the resistance ageing coefficient of the battery pack calculated by taking into account the life cycles N_{c} and considering that, at the end of the life, the resistance is doubled:

$$g_{\text{r}} = \frac{1}{\sqrt{2\text{DoD} \cdot A_{\text{ho}} \cdot N_{\text{c}}}}. \tag{7}$$

By joining the electric and ageing model together, the total model can be obtained, and is shown in Fig. 2. Using (5) and (6), the function $V_{\text{o}}(\text{SoC})$ and resistance R_{in} can be expressed as functions of the ageing process using the moved charge q.

In particular, the integrated model starts from the knowledge of the initial state of charge, SoC_{i}, and the power exchanged by the battery pack, P_{B}. In fact, multiplying (2) by the current I, the following second-order equation is obtained

$$P_{\text{B}} = VI = V_{\text{o}}I + R_{\text{in}}I^2. \tag{8}$$

Solving with respect to the current, we have

$$I = \frac{-V_{\text{o}} + \sqrt{V_{\text{o}}^2 + 4R_{\text{in}}P_{\text{B}}}}{2R_{\text{in}}}. \tag{9}$$

3 Cost analysis procedure

Considering the PV application, the main goal of the present paper is to compare the total cost of the battery, obtained through the sizing procedure proposed in [32] (flow diagram in Fig. 3), with the total cost of the grid, if it is used as a storage system instead of the battery. The plant that will be taken into account for this comparison is a domestic PV system with a lifetime of 20 years.

3.1 Battery cost for off-grid systems

If the grid is not present, as reported in [33], the plant cost is calculated by taking into account the specific battery cost, cost of the battery inverter, capital cost rate, discount rate, and installation/disposal costs of the battery over the 20 years. Starting from the formula reported in [36], the total cost of the battery pack can be evaluated over the 20 years with the following expression:

$$\begin{aligned} C_{\text{battery}} = & \sum_{k=0}^{\lceil 20/\text{BL}\rceil - 1} [m(c_{\text{W}}E_{\text{s}}K_{\text{M}} + c_{\text{ins}}) + C_{\text{ins\_fix}}] \\ & \times \left(\frac{1+c_{\text{r}}}{1+d_{\text{r}}}\right)^{k \cdot \text{BL}} + \sum_{k=0}^{1} C_{\text{INV}}\left(\frac{1+c_{\text{r}}}{1+d_{\text{r}}}\right)^{10k} \end{aligned} \tag{10}$$

where $\lceil x \rceil$ is the ceiling number of x, and all the other symbols are defined in the nomenclature at the beginning of the paper. Moreover, the lifetime of the inverter has been considered equal to 10 years. In order to simplify the expression (10), let us define the following actualising and actualised terms:

$$a_{\text{b}} = \frac{1}{N_{\text{ins}}}\sum_{k=0}^{N_{\text{ins}}-1} \alpha^{k \cdot \text{BL}}; \quad C_{\text{INV}}^{\text{a}} = \sum_{k=0}^{1} C_{\text{INV}}\alpha^{10k}; \quad C_{\text{ins\_fix}}^{\text{a}} = \sum_{k=0}^{N_{\text{ins}}-1} C_{\text{ins\_fix}}\alpha^{k \cdot \text{BL}}$$

where $\alpha=(1+c_{\text{r}})/(1+d_{\text{r}})$, and the number of battery installation is $N_{\text{ins}} = \lceil 20/\text{BL}\rceil$. In this way, (10) becomes

$$C_{\text{battery}} = N_{\text{ins}}m(c_{\text{W}}E_{\text{s}}K_{\text{M}} + c_{\text{ins}})a_{\text{b}} + C_{\text{ins\_fix}}^{\text{a}} + C_{\text{INV}}^{\text{a}}. \tag{11}$$

According to the procedure proposed in [33], the minimum necessary battery mass is the one that assures no blackout during 1 year. Given an annual solar power profile and an annual domestic load profile, this minimum mass is calculated iteratively until a condition with no blackouts is ensured. In general, this minimum

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mass could not be the optimal one from the cost point of view. Indeed, using the minimum mass, the battery pack operates in the whole voltage span with a current, given by the ratio between the power profile and the actual voltage. For a larger mass, a lower voltage span is required to complete the power profile. As a consequence, even if increasing the mass increases the initial cost, the specific energy required is lower, and the voltage profiles change. Furthermore, the ageing effect is minor. Once the minimum mass is obtained, the following iterative procedure is applied. First, a maximum mass, a mass step, and a voltage step have to be chosen. The end of life, number of battery installations, and plant cost over the 20 years can be evaluated using the integrated model of Fig. 2 and plant cost expression (11). After that, the lowest voltage limit, starting from the minimum one, is increased in the chosen voltage step. In this way, the current will be lower, and the efficiency higher. Once again, the integrated model and the cost are evaluated. This procedure is repeated iteratively until the maximum voltage is reached. Afterwards, the same procedure is repeated with an increased mass until the maximum mass is reached.

Now, it is interesting to calculate the unitary cost of the stored energy in the battery, expressed in €/kWh. For the sake of simplicity, let us consider, as a first step, a PV plant that supplies the exact amount of energy absorbed by the load every day. As its power profile does not match the load power request from the load, the storage is necessary to store energy during the day and supply the load after sunset. Using the above-discussed procedure, it is possible to consider the optimal mass of the storage system that minimises the overall costs over the plant life. This optimal mass corresponds to a value for which the plant life is an integer multiple of the battery life. This number corresponds to the number of battery installations, N_{ins}. During its service, the battery is charged/discharged a number of times equal to its lifecycles, which is calculated according to (5). In particular, considering the end of life of the battery when its capacitance is 80% of the rated value, according to (4) and (5), the total charge moved by the battery over its life is as follows:

$$Q_{\mathrm{TOT}} = 2\,\mathrm{DoD}\,A_{\mathrm{h0}}\,N_{\mathrm{c}}\,. \tag{12}$$

Starting from the specific energy E_{s}, mass m, and nominal voltage V_{n} of the equivalent battery pack that we want to model, the initial capacity is as follows:

$$A_{\mathrm{h0}} = \frac{E_{\mathrm{s}}m}{V_{\mathrm{n}}}\,. \tag{13}$$

Considering a constant voltage equal to the nominal one, from (12) and (13), the amount of energy (in kWh) exchanged by the battery over its entire life is as follows:

$$E_{\mathrm{TOT}} = 2\,\mathrm{DoD}\,mE_{\mathrm{s}}N_{\mathrm{c}}/1000. \tag{14}$$

Finally, the unitary cost of the stored energy in the battery, expressed in €/kWh, over its life, can be expressed as follows:

$$c_{\mathrm{sto,\,battery}} = \frac{C_{\mathrm{battery}}}{E_{\mathrm{TOT}}N_{\mathrm{ins}}}\,. \tag{15}$$

This cost is different from the specific battery cost per Wh, c_{W}, referred to as the nominal battery capacity. Moreover, by neglecting both the capital cost and the discount rate cost, (15) becomes independent from the plant life; conversely, it only depends on the total cost of a single battery installation and on its total energy E_{TOT}. Also neglecting both the cost of the inverter and the installation/disposal costs, we can define the specific intrinsic battery cost, expressed in €/kWh, as follows:

$$c_{\mathrm{int,\,battery}} = 1000 \times \frac{c_{\mathrm{W}}K_{\mathrm{M}}}{2\mathrm{DoD}N_{\mathrm{c}}} = K_{\mathrm{eq}}c_{\mathrm{W}} \tag{16}$$

where $K_{\mathrm{eq}} = (1000K_{\mathrm{M}})/(2\mathrm{DoD}N_{\mathrm{c}})$.

3.2 Battery cost for grid-connected systems

If the grid is available, it is possible to work without the storage system or to use a lower size for the battery. Indeed, when the PV plant is not capable of supplying all the required power, the missing amount of power can be drawn from the grid. In this case, the *storage service* can be provided by the grid or by a battery (or by a combination of the two).

Let us start to consider only the grid as storage service. The total grid cost over the 20 years can be expressed as follows:

$$C_{\mathrm{grid}} = 20\left(c_{\mathrm{buy}}E_{\mathrm{buy}} + c_{\mathrm{sell}}E_{\mathrm{sell}} + C_{\mathrm{g}}\right)a_{\mathrm{g}} \tag{17}$$

where E_{buy} and E_{sell} are, respectively, the annual energies bought and sold from/to the grid, expressed in kWh, c_{buy} and c_{sell} are, respectively, the sell and purchase grid energy costs, C_{g} is the annual fixed cost connected with the service provider, and the actualising grid term is defined as

$$a_{\mathrm{g}} = \frac{1}{20}\sum_{k=0}^{19}\alpha^{k}\,.$$

The grid-connected PV plant can exchange energy with the grid. In this way, it uses the grid itself as storage by exporting excess energy during PV production and importing energy when required during dark hours. The power exchanged with the grid can be expressed as follows:

$$P_{\mathrm{grid}} = P_{\mathrm{PV}} - P_{\mathrm{LOAD}} = P_{\mathrm{sold}} + P_{\mathrm{stored}} \tag{18}$$

with the auxiliary condition that the integral over the plant life of P_{stored} is null. Even if, globally, no energy transfer is connected with P_{stored}, a storage service charge is paid to the grid because the prices per kWh to buy and sell the energy are different. In particular, the cost per stored kWh (in the grid) is easily evaluated as follows:

$$c_{\mathrm{sto,\,grid}} = c_{\mathrm{buy}} - c_{\mathrm{sell}}\,. \tag{19}$$

The comparison between the two specific storage costs given by (15) and (19) allows the selection of using the battery or grid as *storage service*. Note that the power P_{sold} related to the net surplus of energy sold to the grid in 1 year is the same in the two cases, and C_{g} is also present in both cases. Therefore, these terms do not introduce any difference in the comparison. Based on the above explanation, we consider the two cases:

- PVs on a grid with batteries;
- PVs on a grid without batteries.

In the first case, the procedure proposed in [32] is applied starting from a null minimum mass because the continuity of service during dark hours is ensured by the grid. The plant cost over the 20 years can be evaluated by adding in the cost expression (11) the cost related to the grid (17). In this way, the total plant cost is defined as follows:

$$C_{\mathrm{tot}} = C_{\mathrm{battery}} + C_{\mathrm{grid}}\,. \tag{20}$$

In this case, the difference between the power generated by PVs and the power absorbed by the domestic load is, in a priority way, exchanged with the storage system. If the latter is fully charged, and the power produced by the PVs is greater than that absorbed by the load, the power difference is injected into the grid. Conversely, if the storage system is fully discharged, and the power produced by the PVs is less than that absorbed by the domestic load, the power difference is drawn from the grid.

Instead, for the second case, no optimal battery mass is calculated because the storage system is not present. Indeed, in this

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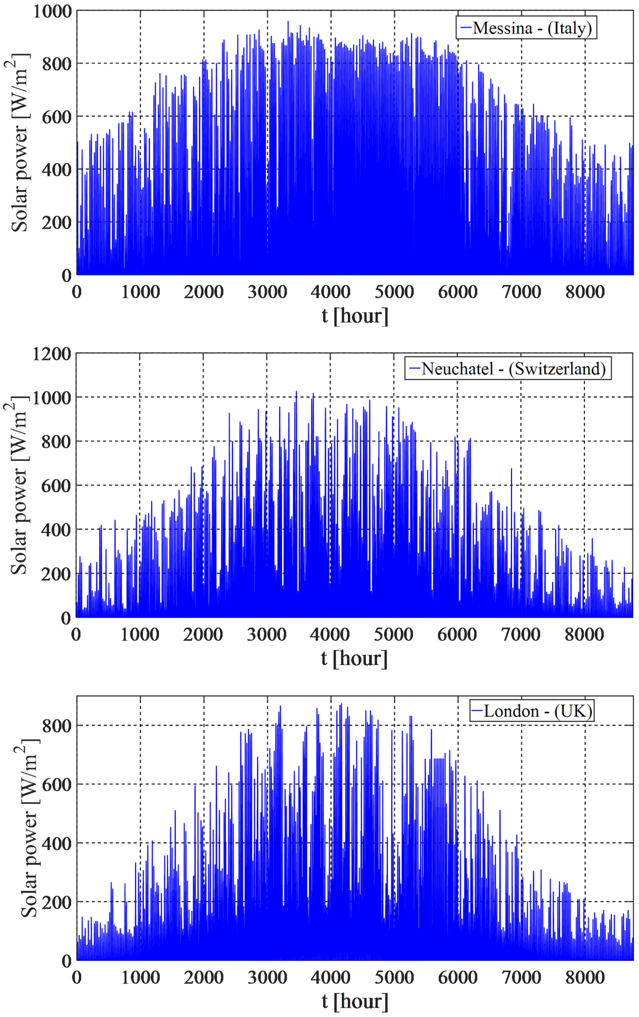

Fig. 4 *Annual solar power profiles*

Table 1 Energy prices

	Italy	Switzerland	UK
c_{buy}, €/kWh	0.16	0.23	0.1
c_{sell}, €/kWh	0.039	0.09	0.056
C_g, €	55	123	141

case, the difference between the energy produced by PVs and that absorbed by the domestic load is completely exchanged with the grid. The costs are only the ones related to grid.

In this way, the related costs are calculated for these two cases. In case the best solution is the one without the storage system, it is possible to calculate the specific battery cost threshold that makes the battery solution convenient, as follows (see the Appendix for details):

$$c_W^{th} = \frac{1}{E_s K_M}\left[\frac{\left(C_{grid}^{g} - C_{grid}^{b+g} - C_{INV}^{a} - C_{ins\_fix}^{a}\right)}{m_o a_b N_{ins}} - c_{ins}\right] \quad (21)$$

where the quantities with the apex b + g refer to the case in which the PVs are on a grid with batteries, and the quantities with the apex g refer to the case in which the PVs are on a grid without batteries. Equation (21) represents the specific cost that the battery should have in order to be more convenient than the grid used as storage. For lower specific battery costs, the solution with the battery becomes more convenient than the solution with only the grid. In order to better understand the meaning of (21), under the hypothesis that the annual energy produced by PVs is at least higher than that absorbed by the load and unitary efficiency of the battery, (21) can be rewritten as follows (see the Appendix for details):

$$c_W^{th} = \frac{1}{a_b K_{eq}}\left[(c_{buy} - c_{sell})a_g - \frac{C_{INV}^{a} + C_{ins\_fix}^{a} + N_{ins} m_0 c_{ins} a_b}{E_{stored}}\right] \quad (22)$$

where E_{stored} is the energy exchanged with the battery or with the grid expressed in kWh and calculated over the plant life. From this expression, we can note that, if both the inverter battery cost and the installation/disposal battery costs are nil, the specific battery cost depends only on the difference between the purchase and sale cost energy of the grid. Otherwise, it also depends on the other costs, on the annual stored energy, and on the optimal mass. It is important to note that, if the inverter battery cost and/or the installation/disposal battery costs become predominant, the specific battery threshold cost may be negative.

As will be shown in the next section, the present costs of batteries lead to a consistent preference for the use of the grid as storage system. However, the comparison between the two specific costs provides information about the necessary incentives to be supported in order to facilitate the spread of distributed storage units. These incentives can be calculated as follows:

$$c_i = c_{sto,\,battery} - c_{sto,\,grid}\,. \quad (23)$$

4 Case study

In order to test the proposed procedure, a case study has been identified. One of the main goals of the paper is to assess the convenience to install a storage system in a grid-connected residential PV plant. Therefore, in the analysis, the only overall cost for the user is considered and all the other advantages connected with the installation of a storage (continuity of service, quality of the voltage, reactive power compensation etc.) are not considered. The storage is used to maximise the self-consumption of the user and, for this reason, its power reference is obtained as difference between the available PV power and the power demand from the residential load. Power is exchanged with the grid only when the storage is full charged (supplying energy to the grid) or fully discharged (absorbing power from the grid).

In order to understand, in different countries, whether the storage installation is convenient or not, three different European countries have been considered. Since the goal is to compare the results only on the basis of the energy prices (for buying and for selling), no incentive tariffs have been taken into account. Indeed, incentives for energy produced by PV could 'dope' the system changing the results without a connection with the real price of energy. The three selected countries are Italy, Switzerland, and the UK. For each country, a city and its correspondent annual solar diagram have been chosen. In particular, the cities are Messina in Italy, Neuchatel in Switzerland, and London in the UK. Their annual solar radiation diagram, retrieved by [37–39], is reported in Fig. 4.

For each site, average energy prices of each country have been considered as reported in Table 1.

The proposed procedure is applicable to any power profile but, to define the case study, power profiles for load and generation have to be selected. In the paper, the suitability of the storage installation is investigated. For this reason, to have the same energy balance in the three countries, the PV systems have been sized in order to have the same annual energy production. This means that in Italy, where the solar power is higher, the smallest PV system is considered, while in the UK, it is used the biggest one. This choice was driven by the choice to compare the storages only on the basis of energy prices, in the three countries, independently on the different incoming due to the different latitude. Fixed the annual PV production to 6750 kWh the PV size, in square metres, are obtained as reported in Table 2.

For what concerns the load, a unique power profile has been chosen for all the three countries. Also if this seems to be a strong hypothesis, this choice was always driven by the will to compare the three countries mainly on the different energy prices more than from other peculiarities that could change also from city to city inside the same country. The daily load power profile has been generated using the tool reported in [40]. Four different daily

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Table 2 Main data of PV plants for the case study

	Italy	Switzerland	UK
S, m^2	35	48	60
η_{PV}		0.14	
η_I		0.9	
PL, years		20	

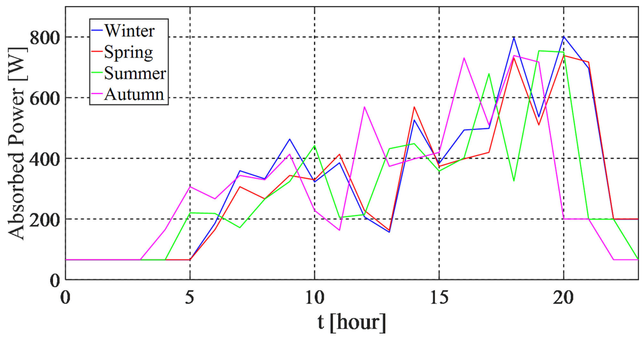

Fig. 5 *Electrical power consumption related to classic family composed of four people for each season, 2700 kWh/year*

Table 3 Main data of batteries used in simulations

	Lithium ion battery	Lead-acid battery
V_n, V	100	100
E_s, Wh/kg	128	35
η_B	0.85	0.75
EoL, %	80	80
Life cycles at 80% DoD	3000	500
c_W, €/Wh	0.32	0.12
K_M	1.1	1
c_{ins}, €/kg	2	0.5
C_{ins_fix}, €	100	
c_r	0.0093	
d_r	0.001	
C_{INV}, €	800	

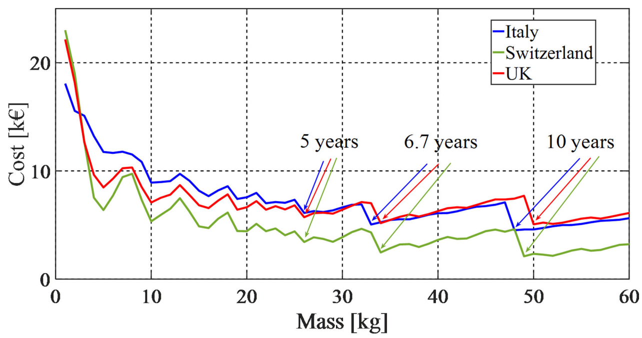

Fig. 6 *Total plant cost versus battery mass for lithium ion batteries*

power profiles have been generated for the four seasons and are reported in Fig. 5.

The annual power profile is obtained concatenating the daily profiles and the total amount of energy demand per year is 2700 kWh. Finally, the battery data used for the simulations are taken from [41–43] and are reported in Table 3.

5 Simulation results

According to the case study definition reported in the previous section, six simulations have been performed: three countries, each with the two types of battery. All the simulations were carried out using Matlab®. The total costs of the plant as function of the battery size are reported in Figs. 6 and 7 for lithium ion and lead-acid batteries, respectively.

It is worth noting that, in any case, when the mass values tend towards zero, the total costs increase. This is a result of the fact that, for small storage masses, the number of replacements over the plant life increases. Consequently, the related battery fixed installation/disposal costs increase as well.

Conversely, when the mass value increases, the total costs tend to decrease until the battery fixed installation costs become less than the other costs because of the lower number of replacements.

Afterwards, there are several local minima which correspond to the mass values for which the plant life is an integer multiple of the battery life. In all the cases, the procedure was stopped when the battery life exceeded 10 years. This was done to take into account the calendar ageing phenomenon according to the lifetime declared by the battery manufacturers.

It is interesting to note that the costs related to the local minima are not very different for each case. Taking into account that the specific battery costs decrease over the years, a solution related to a shorter battery lifetime could be more reasonable considering the plant life of 20 years. For example, considering the Italian case with lithium batteries (Fig. 6), the total cost related to a storage life equal to 5 years is 6.1 k€, while the optimal case, related to a storage life equal to 10 years, is 4.4 k€. In this case, the first choice seems more reasonable to reduce the risk of the investment. Applying this consideration to all the cases, the mass of storages to be installed is around 25 kg for lithium ion batteries and 180 kg for lead-acid batteries independently on the country.

After that, the total costs related to the case in which only the grid is present, according to (17), were also calculated. These results are reported in Tables 4–6 where these costs are compared with the best points of Figs. 6 and 7. Furthermore, the incentives per kWh, according to (23), were calculated and reported in the same tables.

Looking at the results, it is possible to state that, at present, the solution with only the grid used as storage is more convenient in all the cases. The reason for this stands in the actual high specific cost of batteries. The expected cost reduction could change this result in the next years. Moreover, it is possible to state that the solutions with lead-acid batteries are always the least convenient. This is because their shorter lifetime makes their specific cost of energy delivered during their whole lifetime higher than the same cost of lithium ion batteries.

Looking at Tables 5 and 6, the total cost of the case without storages, in Switzerland and in the UK, is negative. This means that the excess of generated energy compensates all the costs and gives an income. It is worth noting that in this income, the PV cost is not considered, because this analysis is focused on the storage.

The cost threshold indicates the maximum specific cost of batteries, making them convenient. For instance, for lithium batteries, in the Italian case, this threshold is ∼0.10 €/Wh. This means that, if the specific cost of the battery was <0.1 €/Wh, the installation of this battery would become convenient. In the case of the UK, the thresholds are negative. This means that the installation of storages, with actual costs of energy and auxiliaries, is never convenient, neither if the storage would be free of charge. This is because the cost of the grid (used as storage) is lower than the fixed costs (mainly the inverter) connected with the use of batteries.

Finally, looking at the incentives, c_i, represents the necessary incentive to be paid per exchanged kWh in order to make the storage convenient. The value of this incentive is similar in the Italian and in the Switzerland cases, while it is necessary a higher incentive in the UK. This is because the cost of the grid (used as storage) is much lower in the UK in comparison with Italy and Switzerland.

6 Conclusions

In this paper, the technical sizing procedure reported in [33], used to find the minimum optimal mass of the battery storage for a stand-alone PV plant, was extended to the case of battery storage for grid-connected residential PV systems. In designing a real

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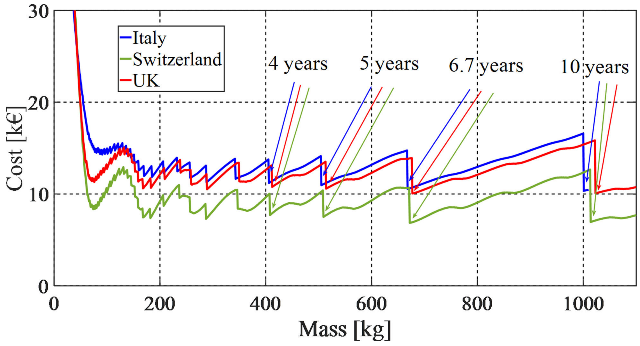

Fig. 7 *Total plant cost versus battery mass for lead-acid batteries*

Table 4 Results for Italy

	Lithium ion battery	Lead-acid battery
m_O, kg	47.1	1000.9
BL, years	10	10
N_{ins}	2	2
C_{tot}^{b+g}, €	4379	10349
C_{tot}^{g}, €	1360	
$c_{sto,battery}$, €/kWh	0.23	0.44
c_W^{th}, €/Wh	0.10	−0.0030
c_i, €/kWh	0.11	0.32

Table 5 Results for Switzerland

	Lithium ion battery	Lead-acid battery
m_O, kg	48.8	1013.3
BL, years	10	10
N_{ins}	2	1
C_{tot}^{b+g}, €	2068	6942
C_{tot}^{g}, €	−1276	
$c_{sto,battery}$, €/kWh	0.24	0.42
c_W^{th}, €/Wh	0.087	0.0089
c_i, €/kWh	0.10	0.28

Table 6 Results for the UK

	Lithium ion battery	Lead-acid battery
m_O, kg	49.4	1022.8
BL, years	10	10
N_{ins}	2	1
C_{tot}^{b+g}, €	4943	10073
C_{tot}^{g}, €	−768	
$c_{sto,battery}$, €/kWh	0.24	0.42
c_W^{th}, €/Wh	−0.074	−0.025
c_i, €/kWh	0.20	0.38

system, the first commercial available size greater than the optimal one has to be selected. The proposed methodology integrates the technical procedure into the economic analysis, so that the major economic findings reflect the real battery performances and expected lifetime according to the operative conditions of use.

Two subcases (PV grid connected with and without batteries) for three different countries and two types of battery were compared. Actual prices of battery storage systems for residential applications, which are in the range of 350–450 €/kWh, make economically inconvenient the installation of BESSs. An energy incentive in the range of 0.10–0.38 €/kWh is needed nowadays to make the BESS a viable and profitable solution when coupled to grid-connected residential PV systems. Examining the results of the total costs with lithium ion batteries and lead-acid batteries in more detail, the least expensive is always the solution with lithium ion batteries, indeed, the incentive required to make economically convenient the installation of lithium battery storage is at least half than the incentive required for installing the lead-acid batteries (€0.1/kWh versus €0.3/kWh for Italy and Switzerland and €0.2/kWh versus €0.38/kWh for the UK).

In addition, for the same amount of energy stored, lithium ion battery packs are smaller and lighter than the lead-acid ones of a factor 3.5 on average, which represents another implicit technical–economic advantage, which is not considered in this analysis, is for the lithium-ion based batteries.

Considering lithium-ion technology, the break-even point in between solution with and without BESS without incentives will be attained when the cost of the complete battery pack will decrease under 0.08 €/kWh. Considering the actual learning curve of 21% for lithium ion batteries, this will happen once the cumulative production will attain 6.9 TWh. (Cumulative production of lithium-ion battery packs was 0.2 TWh in 2016 [1].)

The assessment of the economic viability performed in this work does not take into account the additional benefits from the installation of a BESS. Power quality functionalities as back up services, voltage regulation, and peak shaving can be provided with a battery storage. Actually, these services are not remunerated at residential level, so it was difficult considering their economic value in the actual analysis. At the same way, the analysis does not take into consideration the possible scenarios for the evolution of the electricity and battery pack prices; it will be the object of a future work.

Further in this analysis, the size of the PV system is a fixed variable and the optimal size of the storage is determined by the proposed procedure. In a future work, we will extend the analysis for the integrated optimal sizing of both PV and storage.

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8 Appendix

Let us define the following terms:

$$C_{\text{grid}}^{\text{b+g}} = 20\left(c_{\text{buy}}E_{\text{buy}}^{\text{b+g}} + c_{\text{sell}}E_{\text{sell}}^{\text{b+g}} + C_{\text{g}}\right)a_{\text{g}} \tag{24}$$

$$C_{\text{grid}}^{\text{g}} = 20\left(c_{\text{buy}}E_{\text{buy}}^{\text{g}} + c_{\text{sell}}E_{\text{sell}}^{\text{g}} + C_{\text{g}}\right)a_{\text{g}} \tag{25}$$

The total costs related to the two cases under analysis are then found as follows:

$$C_{\text{tot}}^{\text{b+g}} = C_{\text{battery}} + C_{\text{grid}}^{\text{b+g}} \tag{26}$$

$$C_{\text{tot}}^{\text{g}} = C_{\text{grid}}^{\text{g}}\,. \tag{27}$$

In order to calculate the specific battery cost threshold, we have to impose the following equality:

$$C_{\text{tot}}^{\text{b+g}} = C_{\text{tot}}^{\text{g}}\,. \tag{28}$$

By solving (28) with respect to the specific battery cost, (21) is found.

Under the hypothesis that the annual energy produced by PVs is at least higher than that absorbed by the load and unitary efficiency of the battery, the total costs, related to the two cases under analysis, can also be decomposed by expressing (11), (24), and (25) as follows:

$$C_{\text{battery}} = c_{\text{int, battery}}E_{\text{stored}}a_{\text{b}} + C_{\text{INV}}^{\text{a}} + C_{\text{ins\_fix}}^{\text{a}} + N_{\text{ins}}\,m_0\,c_{\text{ins}}\,a_{\text{b}} \tag{29}$$

$$C_{\text{grid}}^{\text{b+g}} = \left(c_{\text{sell}}E_{\text{sold}} + C_{\text{g}}\right)a_{\text{g}} \tag{30}$$

$$C_{\text{grid}}^{\text{g}} = \left[c_{\text{sto, grid}}E_{\text{stored}} + c_{\text{sell}}E_{\text{sold}} + C_{\text{g}}\right]a_{\text{g}} \tag{31}$$

where

$$E_{\text{stored}} = \frac{1}{2}\int_{20\text{ years}} |P_{\text{stored}}|\text{d}t; \quad E_{\text{sold}} = \int_{20\text{ years}} P_{\text{sold}}\text{d}t\,.$$

E_{stored} is the energy exchanged with the battery or with the grid, while E_{sold} is the energy sold to the grid, both of which are expressed in kWh and calculated over the plant life. As was done for (21), let us impose an equality between the two total costs, using (29)–(31) and, solving with respect to the specific battery cost, (22) is found.

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