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Cost–benefit analysis of battery storage in medium-voltage distribution networks

Carlos Mateo, Javier Reneses, Andrea Rodriguez-Calvo ✉, Pablo Frías, Álvaro Sánchez

ICAI School of Engineering, Institute for Research in Technology (IIT), Universidad Pontificia Comillas, Sta. Cruz de Marcenado 26, 28015 Madrid, Spain

✉ *E-mail: andrea.rodriguez@iit.comillas.edu*

Abstract: The increasing deployment of non-dispatchable generation in electric systems where generation and demand must be balanced at all times has led to a renewed interest in technologies for energy storage. This study presents a cost–benefit analysis of energy storage for peak demand reduction in medium-voltage distribution networks. In particular, the installation of batteries in secondary substations is studied for three realistic large-scale networks representing urban, semi-urban and rural distribution areas. On the one hand, savings in energy costs derived from storing energy at low-priced hours and selling it at peak hours are considered. On the other hand, savings in network reinforcement due to the peak shaving are evaluated. Network reinforcement requirements are assessed using reference network models, large-scale network-planning tools often used by distribution regulators to establish the allowed distribution costs. Additionally, sensitivity to different demand growth ratios and battery capacities is analysed. The final objective is to determine the target cost for batteries to be profitable from the point of view of distribution. Results show that significant savings can be obtained, especially in urban and semi-urban areas.

1 Introduction

The constant need for instantaneous balance of generation and demand is the major constraint in the electric power system, affecting all related activities, from generation and supply to transmission and distribution, at all stages, from planning to operation. Energy storage can provide flexibility for the system to achieve the balance of generation and demand. Traditionally, energy storage has been based mainly on large-scale pumped hydro. Meanwhile, alternatives such as distributed energy storage based on batteries have not been widely deployed due to their high cost and low lifetime. However, in the current context of growing importance of renewable energy sources and increasing presence of generation connected to the distribution networks, there is a renewed interest in distributed energy storage. Much effort has been devoted to the development of many different energy storage technologies so that a decrease in prices may be expected in the near future [1].

The uses and applications of energy storage provided by batteries connected to the distribution networks are numerous [1–5]. Batteries may be used to mitigate the variability of intermittent generation and thus facilitate the integration of distributed generation in the grid. For instance, Alam *et al.* [6] propose a control strategy for storage in households with photovoltaic (PV) panels to better match their generation and demand profiles, whereas Grillo *et al.* [7] analyse the use of storage to balance wind power generation connected to the distribution network. Karanki *et al.* [8] propose an optimisation of the location and sizing of battery energy storage for integrating renewable energy sources minimising energy losses. Transient stability is the main focus of [9], using batteries as a fast balancing mechanism. The different time scales involved in the operation of distribution networks are comprehensively analysed in [10], where the role of batteries for the integration of distributed generation (DG) is discussed, comparing available technologies for different functionalities, from flicker reduction to improvement of network hosting capacity. Batteries are also valuable instruments for voltage control in distribution networks and their use in the presence of distributed generation has been analysed by Wade *et al.* [11], Zillman *et al.* [12] and Moneta *et al.* [13]. Moreover, batteries can help smooth the net demand curve and reduce power flows by supplying local load during periods of peak demand, which is typically referred to as peak shaving. For this purpose, Purvins *et al.* [14] propose two management systems for peak reduction for residential consumers using batteries. These multiple uses of batteries may be combined into multi-objective optimisation, as performed by Tant *et al.* [15] for a residential low-voltage (LV) network with high penetration of PV panels.

In the case of microgrids and islanding operation, batteries may be used for power supply as independent power sources or together with other generation units, as well as for frequency and voltage control [16, 17]. Additionally, electric vehicles (EVs) may feature vehicle-to-grid capabilities, so that they can also be used as distributed storage. Many examples may be found in the literature, where storage provided by EVs is used for the grid to relieve the increasing stress in distribution networks [18], to perform frequency regulation and peak shaving [19] or to benefit from electricity cost savings or reduced cost of network infrastructure [20].

Peak shaving involves several benefits for the system. On the one hand, the reduction of the peak demand results in reduced network costs. Electric power infrastructure must be sized for peak demand scenarios, which lead to an installed infrastructure that is underutilised most of the time. Distributed energy storage can help smooth the demand curve and thus reduce the total peak demand. Therefore, capacity requirements are reduced, as well as network reinforcement needs caused by growth of demand in the long term. Indeed, the use of distributed storage is analysed by Koeppel *et al.* [21] as an alternative to reduce network reinforcements. As a result from the analysis, it can be concluded that network reinforcement typically has lower fault rates, but batteries are easier to install, especially in urban areas where networks are mostly underground. On the other hand, batteries are charged during periods of low demand, where the cost of electricity is typically lower. The energy stored is used during peak demand periods, where the cost of electricity production is much higher; resulting in significant cost savings. These cost savings are analysed for a residential area where PV is coupled with storage batteries in [22].

It is clear that the use of storage in distribution networks can have a positive impact on the system. However, in order to ensure economic efficiency, it is of the utmost importance to carefully analyse and compare the costs involved and the benefits that may be obtained for each use case where distributed storage is involved. This paper presents the cost–benefit analysis (CBA) of energy storage for peak demand reduction in distribution networks for large-scale case studies. The analysis is focused on the business case for distribution companies of the installation of batteries located at secondary substations, performing daily peak shaving and valley filling, as an alternative to traditional network reinforcement at medium-voltage (MV) level. The benefits achieved include savings in energy costs and the reduction of network investment costs. These benefits have been quantified using large-scale network-planning tools, the so-called reference network models (RNMs) [23], often used by regulators to assess efficient distribution costs in order to set allowed revenues for distribution companies. The use of RNMs enables a detailed technical analysis resulting in realistic and reliable estimations for network costs.

This paper is structured as follows. First, after this introduction, the methodology for the CBA is presented and the RNMs used are described in Section 2. Then, the case study is described, presenting the different scenarios considered in Section 3, followed by the results obtained from simulation and CBA analysis in Section 4. Finally, the main conclusions are summarised in the last section.

2 Methodology

This section presents the methodology applied for the CBA for the use of energy storage in the form of batteries in secondary substations to shift demand from peak to valley hours. In the context of technological evolution of batteries and decreasing costs, the main objective pursued by the CBA hereby proposed is to determine the cost of storage that would make the installation of batteries profitable for the distribution system. This target cost is the breakeven point where the net present value [24] of the sum of all costs and benefits equals zero. The benefits assessed include the reduction of network costs in terms of reinforcement to cope with an increasing demand in time and savings in energy costs by buying the energy to store during low demand periods at low prices and selling this energy during peak demand periods at higher prices.

In this paper, three different distribution networks have been analysed. For each one of them, different scenarios of storage capacity will be compared with the business-as-usual situation where no batteries are in place. The proposed CBA comprises a first stage of technical analysis to compute the required network expansion to accommodate demand growth and thus determine savings in network infrastructure. Moreover, the resulting demand curve is estimated, so that savings in energy costs can be obtained. Then, a stage of economic analysis is carried out to monetise the benefits associated to the technical impact of storage. The net present value of these benefits and the cost of storage are considered to obtain the target cost for batteries. A very valuable and innovative feature of the work presented in this paper is the use of actual RNMs to provide realistic distribution networks and accurate expansion and reinforcement costs for the analyses. Therefore, RNMs are briefly described for a better understanding of the technical analyses carried out in this paper in Section 2.1.

2.1 Reference network models

In the following, a brief introduction to RNMs is presented, while more detailed information can be found in [24, 25]. RNMs are optimisation models able to design an electrical network for very large distribution areas with up to a few million consumers. The output of the model is a so-called reference network, which is a theoretical network that complies with the same geographical, reliability and technical constraints as the actual grid at a minimum cost. These networks are typically used as a benchmark for actual distribution networks with a view to allocating revenues of distribution system operators (DSOs) and testing how the introduction of new devices and distributed resources could influence distribution networks [26–29].

Reference networks can be obtained with two different approaches: Greenfield and expansion planning models. The former builds an optimal network from scratch, whereas the latter takes an existing network as the starting point and then build the necessary reinforcements to accommodate new demand or DG production.

RNMs require extensive input data. The quality of these inputs is much related to the quality of the final results. Therefore, it is very important to correctly fine-tune this information with the aim to achieve the desired results. The most relevant inputs are:

- *Network users*: Loads, DG, EVs and storage.
- *Transmission substations*: The RNMs do not optimise the location of transmission substations as this is generally out of the control of DSOs. Thus, information about these substations must be provided as an input to the models.
- A library of standardised network components. To obtain the most realistic network, a standard library of all equipments must be provided, covering standardised power lines, transformers, substations and protection equipment. The cost of these elements, including investment and maintenance costs, must also be indicated.
- Geographical parameters, including geographical features of consumers, topological information and street-map parameters.
- *Technical and quality constraints*: RNMs require not only capacity constraints, but also the maximum and minimum conductor voltages and the limits of reliability indices (such as system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI)).
- *Other modelling parameters*: Simultaneity factors (to account for the fact that the maximum power flow in the different network components does not occur at the same time), cost of energy losses, the weighted average cost of capital and the costs of ditches and posts to install conductors.

On the other hand, the RNMs provide as most relevant results the detailed designed network, continuity of supply indices and the corresponding costs. The planning algorithm of RNMs is very complex. The main steps and inputs are shown in Fig. 1. The objective function minimises the investment and maintenance costs plus the present value of energy losses. Normally, DG and load location are given in these models, although in some cases it is necessary to optimise loads, storage or DG as in [30, 31].

In the first step, DG/loads modelling is made to identify population settlements and classify consumers into five categories: urban, sub-urban, concentrated rural, scattered rural and industrial areas.

The second step consists of computing an optimal network layout. This topological network copes geographical constraints such as

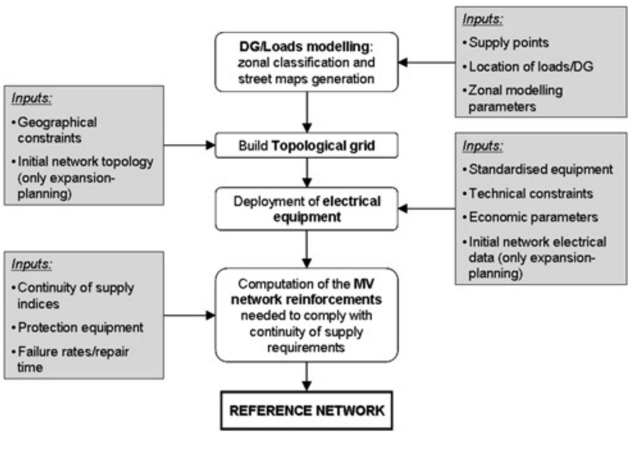

Fig. 1 *Main steps and input data of RNMs*

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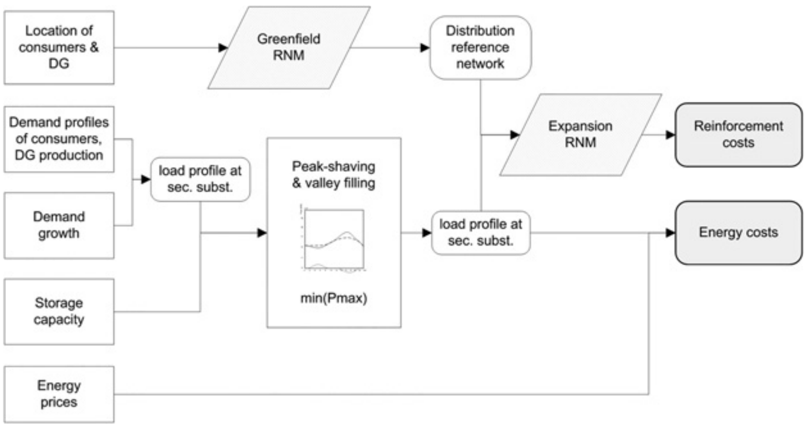

Fig. 2 *Methodology for storage CBA*

forbidden places, orography, street maps and, in the case of the expansion RNM, the topology of the initial network. At this stage, the resulting network has electrical characteristics, although they are not optimised yet. The topological network is built from the lower-voltage levels to the higher ones. The topology of initial MV and LV grids is radial. On the contrary, the initial high-voltage network is messed and designed according to an $N-1$ reliability criterion.

In the deployment of network components stage, a minimisation of distribution network costs is performed, including an estimation of energy losses.

The final step is focused on designing the grid to meet reliability constraints. The final MV network must comply with the minimum continuity of supply indices, which, for example, could be SAIDI and SAIFI indices, as defined in [32].

2.2 Technical analysis

As explained, a detailed technical analysis is carried out to compute the impact of peak shaving with the batteries, following the process depicted in Fig. 2. The scenarios for analysis include different values of installed storage capacity and demand growth for three different distribution areas: namely, urban, semi-urban and rural, as will be presented in detail in Section 3.

First, the Greenfield RNM is used to obtain the model of the actual distribution network that would correspond to the considered area. The location of consumers and DG units is identified and used as an input for the Greenfield RNM.

The daily net load profile of each secondary substation must be determined. For this purpose, standard load profiles for each consumer and generation curves for DG units connected to the corresponding secondary substation are considered. The resulting net profile is obtained applying a simultaneity factor and taking into account a certain level of demand growth. Thus, a preliminary load profile is determined for secondary substations, which correspond to the situation where no batteries are installed. Then, the daily charge and discharge of the batteries connected at the secondary substations for peak shaving is determined. The objective is to minimise the maximum LV demand and maximise the minimum LV demand supplied by the corresponding secondary substation, subject to the restriction of storage capacity and considering the efficiency of the charging and discharging processes. The total volume of energy that can be supplied by the battery is divided into differential blocks. In a stepwise approach, each block is added at each step to the hour of minimum demand. Similarly, the total energy that must be absorbed from the grid is divided into differentials that are gradually subtracted from the LV demand of the hour with the highest load. The output of this step is the daily load profile at the secondary substations.

In a subsequent step, the daily load profiles at secondary substations are fed into the expansion planning RNM to obtain the optimal expansion of the initial distribution network required to accommodate the demand growth. The main contribution of this paper is precisely this detailed analysis using RNMs to obtain a realistic, efficient expansion of the distribution network. Additionally, the expansion planning RNM provides the resulting reinforcement costs, broken down into investment and operation and maintenance (O&M) costs.

In addition, the daily charge and discharge of batteries and daily load profiles at secondary substations will be used to determine the savings in energy costs achieved by peak shaving considering the different hourly electricity prices.

2.3 Economic analysis

Once the technical impact of battery storage has been assessed, a stage of economic analysis follows for the proposed CBA to determine the target cost of batteries to achieve profitability.

On the one hand, savings in network costs are determined as the difference in reinforcement costs obtained to fit a certain demand growth over a certain period of time with and without storage capacity. The considered electric infrastructure has a very long lifetime and therefore distribution investment projects are typically assessed over periods of 40 years. The results of the expansion RNM for the considered case studies include the investment, that is, equipment and installation, and O&M costs of MV/LV transformers for secondary substations and MV lines and conductors for distribution feeders.

On the other hand, savings in energy costs are assessed based on assumed electricity prices for the considered period. It must be noted that due to the many uncertainties involved, hourly electricity prices over a period of 40 years must be considered as rough estimations.

Table 1 Characterisation of distribution areas

	Urban area		Semi-urban area		Rural area	
	Number	Installed capacity, kVA	Number	Installed capacity, kVA	Number	Installed capacity, kVA
substations (132/20 kV)	3	280, 000	2	160, 000	1	80, 000
transformers (20/0.4 kV)	443	207, 120	102	48, 790	52	18, 410
MV consumers	48	45, 350	111	110, 880	156	21, 700
LV consumers	133, 544	783, 362	33, 236	175, 959	14, 756	73, 578

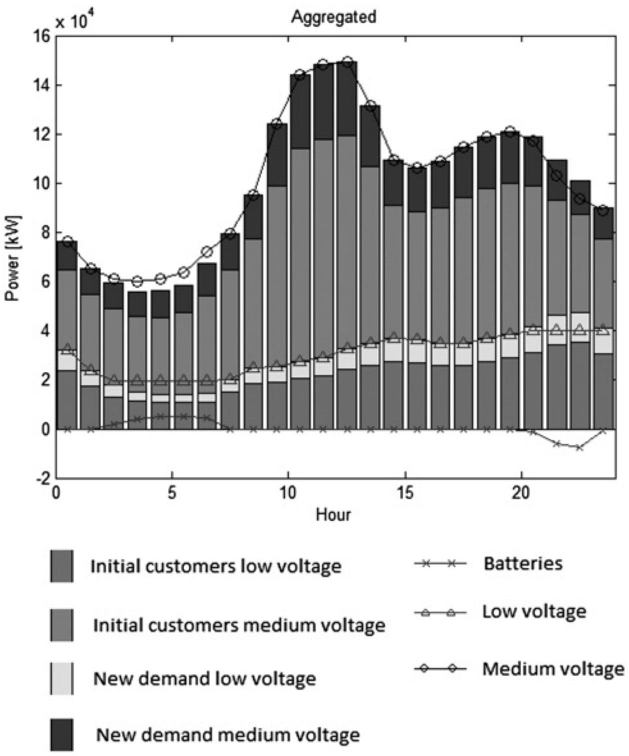

Fig. 3 *Hourly load profile*

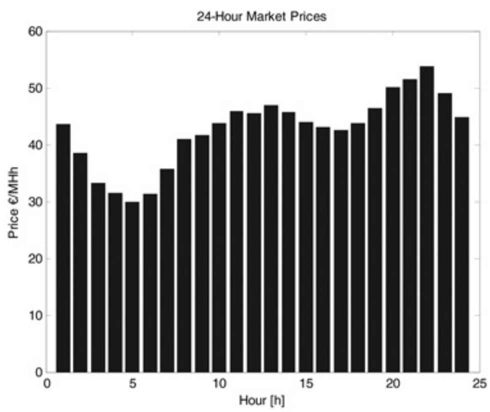

Fig. 4 *Hourly electricity price used for CBA*

For the CBA presented in this paper, historical hourly electricity prices registered in the wholesale market have been considered to obtain one average 24 h electricity price curve. It must be noted that due to the efficiency of the batteries, there are energy losses in the process of charge and discharge.

Regarding the cost of batteries, investment and O&M have been distinguished, assuming that O&M represents a fixed share of the total cost. During the long period of time considered, battery replacement must be considered in accordance with the lifetime of batteries.

Additionally, a certain discount rate must be fixed for the CBA to take into account the time value of money, which becomes especially relevant for such a long period of time, to incorporate the associated risk and the value of referral of investments.

3 Characterisation of case studies

As mentioned, the proposed CBA is applied for a set of different scenarios to assess the potential contribution of storage and sensitivity to the most relevant parameters, including:

- Three electric distribution areas, corresponding to rural, semi-urban and urban networks.
- Three annual demand growth scenarios: 2, 2.5 and 3% to account for the connection of new network users and the increase of demand of existing network users.
- Six values of battery storage capacity: 0, 10, 20, 40, 70, 100 and 200 kWh at each secondary substation.

The main characteristics of the three large-scale distribution areas are presented in Table 1. The distribution networks consider from the 132 kV down to 400 V. Each network has a different share of LV consumers, which are mostly residential, and industrial consumers connected at the MV grid. The infrastructure has been sized applying simultaneity factors of 0.2 and 0.8 for the LV and MV contracted powers, respectively [23].

For each industrial and residential consumers, a typical 24 h load profile is used, based on standard profiles publicly available by the Spanish National Energy Commission [12]. Fig. 3 presents the resulting aggregated initial and incremental demand as an example for the case of the semi-urban network, with 3% annual demand growth and storage capacity of 200 kWh at each secondary substation. Moreover, the corresponding power profile of the storage is also shown in Fig. 3, which has been determined as the result of the minimisation of the peak demand of the LV net load. The storage batteries are fully charged during the valley hours of LV demand to maximise the minimum demand and fully discharged during the peak LV demand hours to minimise the maximum demand. The energy efficiency of the batteries is assumed to be 80% for a complete cycle of charge and discharge. Furthermore, the lifetime of batteries has been assumed to be 10 years.

The parameters assumed for the present CBA analysis are detailed below:

- *Useful lifetime of transformers and lines and period considered for CBA*: 40 years.

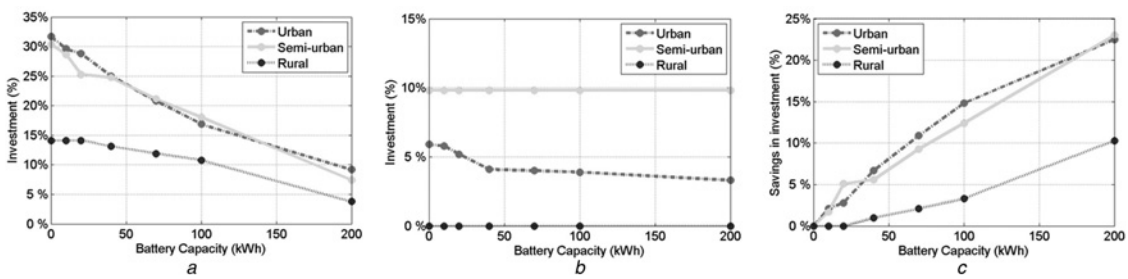

Fig. 5 *Reinforcement investments for a 2% annual demand growth*

a Required investment in MV/LV transformers
b Required investment in MV feeders
c Savings in investment requirements

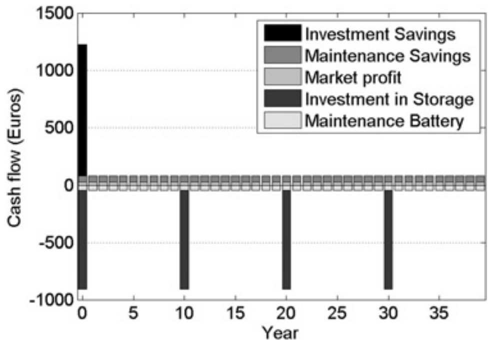

Fig. 6 *Cash flow example corresponding to the urban case with a 3% annual demand growth*

- *Useful lifetime of batteries*: 10 years.
- *Investment and O&M cost of infrastructure*: Typical values from manufacturers stated in RNM catalogue [23].
- Annual O&M cost for batteries: 5% of battery total cost.
- Discount rate: 7%.
- *Hourly electricity prices*: Average hourly prices registered in the Spanish wholesale market for the period 2000–2012 published by the electricity market operator OMIE, shown in Fig. 4.

4 Results

4.1 Simulation results

Simulations have been carried out for the scenarios described in the previous section. For all cases, required reinforcement investment and O&M costs are compared with those with no storage. For the sake of clarity and simplicity, only the most relevant results are summarised in this section.

One interesting aspect is that as the capacity of the battery is higher, in order to achieve peak shaving, batteries are required to increase more quickly in terms of energy than in terms of power. This is due to the fact that the peak demand power reduction is larger when the period is narrower. Given a certain energy E2 equal to E1, the achieved peak reduction R2 is lower than R1. This also has an impact in the simulations, with the consequence that large batteries will achieve comparatively less savings.

As an example, Fig. 5 shows the required reinforcement investments in MV/LV transformer substations (Fig. 5*a*) and MV feeders (Fig. 5*b*) for an annual demand growth of 2%, considering only investment costs, since O&M costs are not significantly affected by the introduction of storage, and expressed as a percentage of the cost of the initial network. The savings in infrastructure investments are also depicted (Fig. 5*c*). As can be seen in this figure, substation reinforcements are needed in the three case studies, but they decrease significantly as battery capacity increases. This trend depends on the type of area for MV feeder investments. In the urban area, the tendency is somehow similar to the investments in MV/LV transformers, with the reinforcement cost slightly decreasing as the battery capacity increases. On the contrary, in the semi-urban area there are reinforcements in MV feeders, but they are independent of the battery capacity. Finally, there are no reinforcements needed in MV feeders for rural areas. It is important to note that the reinforcements in MV feeders may have been limited due to the size of the used distribution areas. Resulting investment savings show a similar behaviour for semi-urban and urban areas. In the rural case, the savings are lower, and they are only observed for battery capacities of 40 kWh or larger.

4.2 CBA results

The aim of the CBA is computing, for each case, the objective cost of batteries so that the net present value [24] of the sum of cost savings due to reduced reinforcement infrastructure requirements and lower electricity prices and the costs of batteries is equal to zero. As an example of such breakeven point, Fig. 6 shows the cash flow where the net present value of the investing in 10 kWh batteries for the urban case with a 3% annual demand growth is zero. At an investment storage cost of 86 €/kWh, the decision of investing in storage in (with subsequent replacement in time at present cost) instead of investing in traditional network reinforcement would yield the same results at the present time. There are very high savings in reinforcement investments at the beginning, when the sizing of the infrastructure to meet future demand growth must be made. There are also annual savings in network maintenance, as well as annual incomes obtained from the market, as mentioned above. On the other hand, there is an increment in costs due to the yearly expenses in maintenance for the batteries, and due to the periodical investments in batteries every 10 years for its replacement (the considered useful life for batteries) at present cost. One of the conclusions of this cash flow is that the batteries could become profitable not only by a cost decrease, but also by a useful life increase.

The resulting breakeven storage costs, gathered in Table 2, can be interpreted as the objective costs for the batteries to become economically profitable. The results obtained for these cases show that the optimal size of storage varies for each type of grid in a non-monotonous trend, so that increasing the size of storage can in

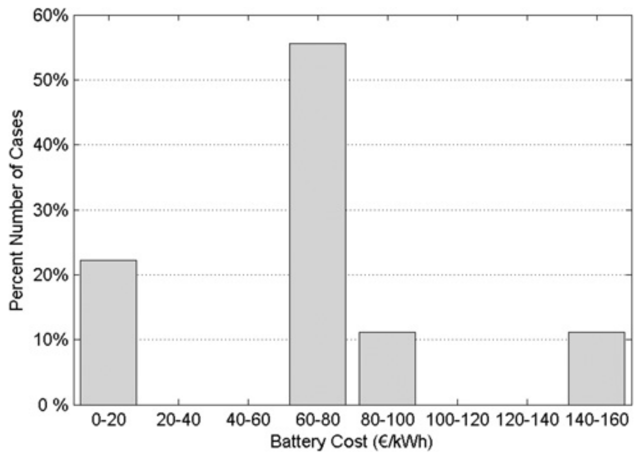

Fig. 7 *Histogram of target battery costs for a 10 kWh battery capacity*

Table 2 Target battery cost

	Rural			Semi-urban			Urban		
ΔAnualDem, kWh	2%, €/kWh	2.5%, €/kWh	3%, €/kWh	2%, €/kWh	2.5%, €/kWh	3%, €/kWh	2%, €/kWh	2.5%, €/kWh	3%, €/kWh
10	16	16	62	64	63	63	68	150	86
20	16	16	39	80	63	62	62	103	91
40	22	22	40	52	67	61	73	80	74
70	24	20	31	51	61	56	65	65	68
100	24	22	27	49	57	53	61	63	61
200	27	22	23	46	45	41	49	52	49

some cases be beneficial, whereas in some others, lower volumes of storage capacity lead to lower target costs.

It is remarkable that the best target costs are obtained in the range 10–30 kWh, which coincides with the range of batteries used for electric vehicles. Hence, it can be concluded that each secondary substation would require the installation of a single battery. Therefore, if the electric vehicle penetration becomes significant, their batteries could also be considered for electrical uses such as the one proposed in this paper. Furthermore, second-live EV batteries could be considered as a low-cost alternative for secondary substation uses.

The obtained results are summarised in a histogram in Fig. 7. In this figure, the three networks types are considered, but only for a 10 kWh battery, which is the one with a better cost–benefit relation. The lower target values correspond to the rural area, in which the savings would be very low, as seen before. The histogram shows that a target cost of 60–80 €/kWh would be generally required for batteries to start becoming economically interesting for the energy storage in the MV/LV transformers. However, in some specific cases (e.g. the urban network with 2.5% annual demand growth), even a battery at a price of 150 €/kWh could become economically profitable.

5 Conclusions

Nowadays, with an increasing deployment of non-dispatchable generation in electric power systems, storage technologies are becoming of great interest. This paper has analysed the distributed use of battery storage in MV distribution networks.

With this aim, a number of case studies have been assessed, including three realistic large-scale networks (representing urban, semi-urban and rural distribution areas). In the urban and semi-urban cases, the impact of the battery storage has been greater than in the rural area. Besides, different demand growth ratios and battery capacities have been simulated. Although the necessary reinforcements have been dependent on the demand growth, the savings have been more or less independent on it, as far as the peak reduction of the battery is lower than the peak increase of the demand growth. For each scenario and case study, two different savings have been considered. On the one hand, the savings related to storing energy at low-priced hours and selling it at peak hours, taking into account the battery performance. On the other hand, the savings in network reinforcements due to the peak shaving achieved by the batteries. This last impact has been assessed using RNMs, by calculating for a given scenario the reinforcements required in an incremental scenario. The analyses have shown that significant savings can be obtained.

This cost savings have been compared with the batteries cost (including investment and O&M) in a CBA. The final objective has been obtaining a target costs for batteries, under which they can be considered to be profitable. The results have shown that large battery capacities need a lower target cost. The exact values should be taken only as a reference, given the uncertainty of electricity prices and the long lifetime of network investments. In the case studies presented in this paper, the obtained results show how a target cost of 60–80 €/kWh would be generally required for batteries to start becoming economically interesting for energy storage in secondary substations. In some specific cases, even batteries at a price of 150 €/kWh could become economically profitable. Batteries nowadays have significantly higher costs [33, 34], so it can be concluded that this particular use of storage does not represent a beneficial alternative for the considered cases.

The work presented in this paper can help understand the business case behind the use of storage located at secondary substations to perform peak shaving, the main aspects involved and the circumstances that could make it indeed profitable for the distribution system. A drastic decrease of storage batteries costs could take place in the future for different storage technologies. Furthermore, an increased lifetime would also contribute to achieve the profitability of this use of storage. Moreover, higher electricity prices would increase the potential energy cost savings, thus decreasing the target cost of storage for this application. It must be also pointed out that for other applications such as integrating distributed generation (e.g. PVs) the batteries could be interesting even at higher costs.

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