A technical, economical and regulatory analysis of storage systems incorporation in the Uruguayan electricity market

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***Abstract*— This paper studies the possibility/perspectives of introducing lithium ion battery storage in the Uruguayan electrical system, as a mean of increasing its flexibility. This storage resource was chosen among others as it is the most promising technology considering their recent remarkable advances. In order to understand the impact on the electric system, firstly a long-term simulation was done so as to determine when this system would become profitable. Then three annual simulations were executed comparing the system operation (i.e. costs, the energy not supplied, CO_2 emissions and generation mix), for two cases with batteries (with different participation models), and for the case without them. Finally, the regulatory aspects related to storage penetration that are under debate nowadays in the PJM[1] and UK markets were studied in order to learn some lessons for the development of an adequate regulatory framework in Uruguay. It was found that a lithium ion battery of 80 MWh/20 MW becomes viable by 2039 and its annual operation can reduce the energy the system fails to deliver, the annual thermal generation, CO_2 emissions and the system's marginal cost. Moreover, some barriers and business opportunities were found. If barriers are removed and new opportunities are developed batteries could become viable before.**

***Index Terms*— Energy storage, optimization, filtering capacity, participation models, regulatory framework**

I. Introduction

This work is part of a Master of Science Thesis in Energy Engineering. The main objective is to analyze the possibility of introducing storage resources in the Uruguayan electrical system as a mean of increasing its flexibility. Recently Uruguay has undergone a diversification of its generation matrix, which led to a huge introduction of wind power in the first place and solar in a second stage [1]. This transformation increased the country's energy autonomy, the electrical system reliability, reduced costs and CO_2 emissions. However, the introduction of intermittent resources, such as wind and solar generation, has some challenges. The main one is the necessity of having backup capacity to deal with the natural fluctuations of these generation resources. Until now, Uruguay is capable of dealing with these fluctuations because of the big hydroelectric capacity installed. Nevertheless, this resource is completely exploited, and so, as more wind and solar generation is installed, there will come a time when some other filtration mechanism will be needed (i.e. a mechanism able to deal with generation intermittencies which can provide the missing instant power to supply the required demand at every moment). In this work, a candidate mechanism is studied: lithium ion batteries storage.

II. Impact on the operation of the Uruguayan electric system

In this section, the impact of incorporating lithium-ion battery storage on the electric system's operation is analyzed. This resource was chosen as a result of a research among different storage technologies that found it as the most promising one [2]. Firstly, an adequate model for their participation was developed. This model tries to consider their nature and limitations. Then a long-term analysis of the electric system was done, and finally annual simulations were carried out in order to understand the resulting system operation with lithium ion batteries.

A. The model

This work was done using the software SimSEE, an object-oriented platform that has dispatch models for most generators and demands and using them simulates the optimal operation of electric systems [3]. In each simulation step, the dispatch problem is solved with the purpose of supplying the demand at the lowest cost. This is a multi-stage problem as the cost of supplying the demand in the simulation horizon is the sum of the costs in each of its steps. If there are no reservoirs in the system, the problem may be decoupled and minimizing the total cost is the same as minimizing the cost of each step. However, when the system does have reservoirs, the decision of using a resource in the present affect the future, and the problem cannot be decoupled. In these cases, it is necessary to calculate first the impact of the reservoirs in the total cost, i.e. the cost derivates with respect to the reservoirs state variables. These derivates are then taken into account in the simulation as a variable

[1] PJM is a regional transmission organization in USA that serves several states including Pennsylvania, New Jersey and Maryland (https://www.pjm.com/)

"opportunity" cost associated to each storage unit [2]. Taking these into account a model for the battery operation was developed. The state variable for the battery was chosen to be its state of charge. After each simulation step, the state of charge is calculated by equation (1), considering its physical behavior both as generator and demand.

$$C_{k+1} = C_k - \frac{P_G}{\eta_G} \Delta t + P_D \eta_D \Delta t \qquad (1)$$

Where C is the state of charge of the battery, P_G is the power delivered to the network, P_D the one taken from the network, η_G and η_D are the battery efficiency for each case respectively and Δt is the simulation time step. In this work, a global efficiency of 0.81 was assumed, with the same value for each of them [4].

Regarding the dispatch, the energy delivered by the battery has a variable "opportunity" cost, related to the impact of using the resource on the total cost, as was explained before. However, this is not the only cost associated to the battery. When a battery operates it degrades, losing part of its capacity in every cycle it makes. The cost related to this process must be considered in order to assure that the battery recovers the costs incurred in its operation.

There are different degradation models find in literature [5]. Degradation mechanisms are really complex methods which depend on multiple factors: temperature, humidity, life calendar, depth of discharge, charge/discharge current rate, state of charge, over charge and over discharge. As temperature, humidity, over charge and over discharge may be controlled they won't be considered in this model. On the other hand, the current rate and the state of charge have a minor effect on degradation. With these hypotheses in mind, and assuming a quadratic dependency with the depth of charge as in [6], the simplified degradation model is given by equation (2).

$$D = \frac{1}{N_C(\delta)} = e^{-\alpha}\delta^{\beta} \qquad (2)$$

Where D is the degradation in a complete cycle, δ is the depth of discharge, $N_C(\delta)$ is the number of cycles a battery can make at a depth of discharge δ and α and β are two parameters that can be obtained from the manufacturer's curve for $N_C(\delta)$.

It can be proved that the degradation in a time step Δt derived from equation (2) is given by equation (3), where $D_{\Delta t}$ is the degradation in a time step Δt and u(t) is the compliment of the state of charge.

$$D_{\Delta t} = \frac{e^{-\alpha}}{2} \left| u(t)^{\beta} - u(t+\Delta t)^{\beta} \right| \qquad (3)$$

Finally, the variable cost associated to degradation is given by equation (4), where the UnityCost is the capital cost of replacing a cell in USD/kWh.

$$cv_D = UnityCost \times D_{\Delta t} \qquad (4)$$

B. Methodology

In the first place the evolution of the opportunity cost of storage systems was analyzed by adding batteries to the long-term expansion plan made by the Institute of Electrical Engineering of Uruguay for the period 2019-2046, with a weekly step. This was calculated as the difference between the earnings when selling energy at the marginal cost of the system (e.g. at peak times) and the cost of buying it at the marginal cost (e.g. at off-peak times). In the simulation three different capacities were examined: 80 MWh, 400 MWh and 800 MWh. For each of them seven charge and discharge powers were considered, taking a base case with both powers equal and a capacity of delivering energy for 8 hours, and making then variations over it. The computed marginal values of storage systems (i.e. opportunity costs of the storage systems) were then compared to their capital costs based on Lazard Levelized Cost of Storage 1.0-4.0 [7] so as to determine when these systems become viable and which capacity is the most suitable to the system.

Considering that introducing a battery in an expansion plan that does not consider them as expanding units does not lead to the optimal operation neither of the battery nor of the system, a second expansion plan for the period 2019-2046 was made using the software OddFace, a platform related to SimSEE that simulates the optimal system expansion of electric systems. The expansion units considered in this plan and its costs by 2020 are shown in Table I. These were selected in accordance to Uruguay's energy policy. The capacity of the batteries was determined from the first analysis, as the one with higher opportunity cost, and its power as the worst case of the seven cases considered. Its cost was calculated from Lazard and a decay rate of 10% over the 70% of the investment was considered in order to contemplate the rapid decay in battery costs [7]. For solar, wind and thermal units no decay in their cost was taken into account.

TABLE I. EXPANSION UNITS.

Expansion units		
Technology	***Power***	***Cost [1] [7] [8]***
Wind	50 MW	50 USD/MWh-avail
Solar	50 MW	50 USD/MWh-avail
Thermal	60 MW	14 USD/MWh-avail
Li-ion battery storage	80 MWh	57 MUSD[2]

Finally, using the optimal expansions plans obtained, three different annual simulations for 2039 with hour step were analyzed. This year was chosen as it was the one in which the first battery was installed in the system. The three cases studied were a "Base Case" with no battery storage, a "Battery Case" with battery storage and no degradation, and a "Degradation Case" in which the degradation was incorporated. Neither of the cases considered international exchanges of energy with the region. In these simulations the impact of batteries on the electric system operation was studied, observing in particular the system failure, the system's thermal generation, the CO_2 emissions, and the cost of supplying the demand and its risk aversion. In addition, an economic analysis on the battery benefits was done, comparing the cases with and without degradation in order to understand the impact of operation in the battery lifespan.

Our analysis was focused on the impact of batteries on the generation expansion and the system's operation and not on their

[2] MUSD: millon dolars

impact on the grid. Developing a model for this impact would complement the analysis of batteries incorporation and would probably modify their introduction date.

C. Simulation Results

Fig. 1 shows the computed marginal value for 80 MWh of capacity and the seven cases for power rates while Fig. 2 shows the computed marginal value for 400 MWh and 800 MWh of capacity and the seven cases for power rates for each of them. From Fig. 1 and 2 it can be concluded that smaller capacities see a greater benefit, becoming profitable sooner. Benefits grow in time, consistent with an increment in intermittent resources (solar and wind units) while hydroelectric units, which are the ones acting as filter nowadays, remain the same. It can also be noted that for 80 MWh of capacity systems with greater charging power rates see greater benefits at the beginning of the period. This situation is reverted at the end, becoming more valuable having greater discharging power rates.

As Fig.1 shows, an 80 MWh battery seems to become profitable between 2026 and 2034, depending on its cost evolution. However, the marginal value of the storage capacity was computed using the marginal cost of the system. In Uruguay, the spot price is calculated as the marginal cost with a cap of 250 USD/MWh. So, their revenue for buying and selling in the spot market is lower than its marginal value. In order to recompose the optimal investment signal, an additional payment for the services of the storage capacity should be considered.

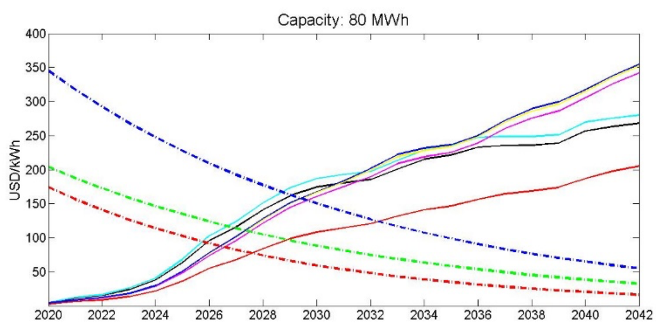

Figure 1. Continuos lines represent marginal value evolution for 80 MWh for different charge and discharge rate: 10/10MW (red), 30/10MW (black), 40/10MW (green), 50/10MW (cian), 10/30MW (magenta), 10/40MW (yellow) and 10/50MW (blue). The dash lines are Li-ion battery costs evolution starting in 2017 minium cost (green), maximun cost (blue) and 2018 proyection (red).

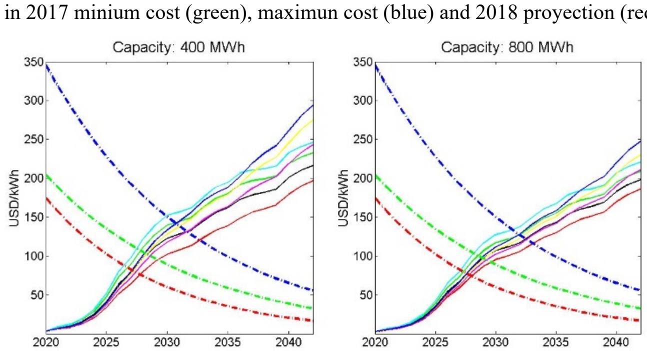

Figure 2. Continuos lines represent marginal value evolution for 400 and 800 MWh for different charge and discharge rate. In the left one: 50/50MW (red), 75/50MW (black), 100/50MW (green), 125/50MW (cian), 50/75MW (magenta), 50/100MW (yellow) and 50/125MW (blue). In the right one: 100/100MW (red), 130/100MW (black), 160/100MW (green), 200/100MW (cian), 100/130MW (magenta), 100/160MW (yellow) and 100/200MW (blue). The dash lines represent Li-ion battery costs evolution starting in 2017 minium cost (green), maximun cost (blue) and 2018 proyection (red).

After computing the optimal expansion plan with batteries, it was found that an 80 MWh battery actually becomes profitable in 2039 for the case of charge/discharge rate equal to 20 MW. This is why this was the year in which annual simulations were computed. The generation matrix considered in the "Base Case" and both cases with batteries, were the result of these expansions, which are shown in Table II.

TABLE II. EXPANSION CAPACITIES BY 2039.

Expansion Capacities by 2039		
Technology	***Base Case***	***With Batteries***
Wind	3,150 MW	3,100 MW
Solar	1,900 MW	2,050 MW
Thermal	300 MW	300 MW
Li-ion battery	----------	320 MWh

Table III shows the annual energy not delivered by the system as a result of the three annual simulations (see Section II. B.). As expected, this is bigger in the "Base Case". This is related to the fact that batteries can act as contingency reserves. However, due to the small capacity installed by 2039 their effect is still small by this year. It can also be appreciated that the case "Degradation" fails to deliver even less energy than the "Battery" case. When incorporating the degradation model, the battery needs higher differences in market to buy and sells its energy, as it needs to recover higher operation costs. Therefore, the resulting operation allows the battery to take better advantage of the price rise during system failures, decreasing the energy not delivered. Finally, from Table III it can be also concluded that the energy not delivered increases in dry years, being more valuable in those cases to have batteries installed.

TABLE III. ENERGY NOT DELIVERED. 5% DRY ARE THE 5% CASES WITH LESS HYDRAULICITY.

Energy not delivered		
Base (50%)	***Battery (50%)***	***Degradation (50%)***
2,266 MWh	2,002 MWh	1,878 MWh
Base (5% dry)	***Battery (5% dry)***	***Degradation (5% dry)***
10,030 MWh	9,230 MWh	8,914 MWh

Table IV shows the supply costs for 2039 for the three different cases studied. This is calculated as the sum of the generators variable costs with the costs associated to failures. The incorporation of batteries does not represent neither a saving nor an increase in costs as differences are lower than 0.5%, being slightly greater in most dry cases. The reason for this is that batteries compete with hydraulic dams with reservoirs in the provision of services. It is in dry years when the benefit of having batteries is greater.

TABLE IV. SUPPLY COSTS. 5% DRY ARE THE 5% CASES WITH LESS HYDRAULICITY

Supply costs		
Base (50%)	***Battery (50%)***	***Degradation (50%)***
938.0 MUSD	938.6 MUSD	940.5 MUSD
Base (5% dry)	***Battery (5% dry)***	***Degradation (5% dry)***
1,054.1 MUSD	1,048.6 MUSD	1,053.6 MUSD

Fig. 3 shows the system's marginal cost for four months in the year, each one corresponding to a different season. It can be noticed that both battery cases reduce the system marginal cost in general. These reductions are bigger in July because it is when thermal contribution is greater and the probability of failure too.

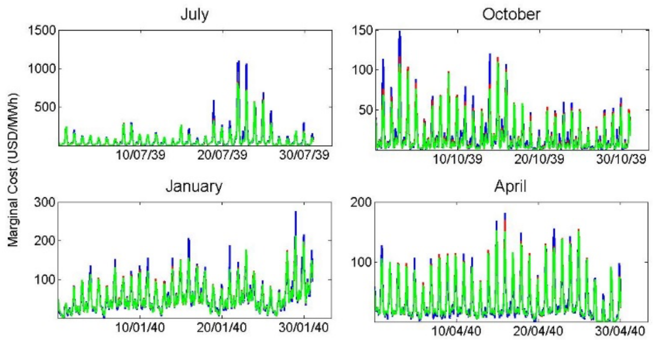

Figure 3. Marginal cost. In blue de "Base" case, in red de "Battery" one and in green the "Degradation" case.

Table V shows the CO_2 emissions for the period simulated. For a generating unit *m*, which consumes a fuel *i*, its emission factor EF_{my}, for year *y* in tonCO_2/MWh is calculated with equation (5). EF_{CO2miy} is the average emission factor for fuel *i* and η_{my} is the average efficiency of the unit *m* on year *y* [9].

$$EF_{m_y} = \frac{EF_{CO2_{miy}} \times 3.6}{\eta_{my}} \qquad (5)$$

As can be seen in Table V, the incorporation of batteries reduces CO_2 emissions. The reason of this reduction is the decrease in thermal generation, which is of 99 GWh in the "Base" case, 90 GWh in the "Battery" one and 88 GWh in the "Degradation" case. This is reasonable considering that batteries compete with thermal generation delivering energy to fulfill the demand supply during peak hours.

TABLE V. CO_2 EMISSIONS.

CO_2 Emissions		
Base	***Battery***	***Degradation***
1.62 x 10^5 ton	1.44 x 10^5 ton	1.33 x 10^5 ton

Finally, an economic analysis was done. Table VI shows the battery earnings, calculated as the difference of the energy sold at the spot price and the energy bought at that price. It can be noticed that the earnings are bigger when the degradation model is added. Although the model incorporates an additional variable cost, the resulting operation allows the battery to take advantage of the market prices differences more efficiently, making it earn more money. Moreover, in all of the cases simulated the earnings are greater than the investment's annuity, which is of 1.1 MUSD for an 80 MWh/20 MW Li-ion battery. It can also be appreciated that the benefit is greater in dry cases, as could be anticipated.

To estimate the impact of the degradation model on the battery lifespan a variable R, associated to the remaining life is defined as:

$$R_{k+1} = R_k - D_{\Delta t} \qquad (6)$$

Where $D_{\Delta t}$ is calculated using equation (3). When R=0 the battery has to be replaced. In this work the value of R after the operation of a whole year, R_{an}, was determined. Assuming that the battery use is similar over the years, the number of years before replacement, i.e. its resulting lifespan, is calculated as:

$$N_{years} = \frac{1}{1-R_{an}} \qquad (7)$$

With the "Battery" case N_{years} = 2.8 years while with the "Degradation" case N_{years} = 13.4 years. These values were compared with the PAYBACKS, which are of 5.9 and 7.8 years respectively. These means that the battery investment is not profitable with the operation resulting of the "Battery" case.

TABLE VI. BATTERY EARNINGS FOR 80 MWH/20MW.

Battery earnings		
Base (50%)	***Battery (50%)***	***Degradation (50%)***
NC	1.7 MUSD	2.1 MUSD
Base (5% dry)	***Battery (5% dry)***	***Degradation (5% dry)***
NC	3.1 MUSD	3.7 MUSD

III. REGULATORY ASPECTS

After understanding the impacts and benefits of installing a battery on the electric grid a regulatory analysis was done, trying to identify possible barriers and other business opportunities for their deployment. If barriers are removed and other business opportunities are developed batteries could become viable even before the year obtained as a result of considering only battery marginal earnings in energy arbitrage (see Section II). In this work two markets were studied, UK and PJM, trying to learn some lessons to apply then in Uruguay.

A. Batteries classification in electricity markets

Technically batteries can provide services in any of the four activities of the electric sector: generation, transmission, distribution and commercialization. This is why different market agents may be interested in their property and operation. How they are classified has important consequences because of the separation requirement between the monopolistic activities of the grid and generation and commercialization, in which competition is recommended to be present. This requirement is fundamental to defend competition. In most electricity markets in which storage systems are present, these are classified as generators. This prevents transmission and distribution companies to owe these assets and so storage systems are prevented from receiving a remuneration from regulated tariffs for providing services to the grid. In order to solve this problem, UK is discussing the possibility of defining a new category for storage system so as to distinguish them from generators [10], while the FERC believes it is enough to define new mechanisms of participation in markets which takes into account the nature of this resources allowing them to provide multiple services in different activities of the energy sector [11]. This last seems to be the most adequate path to begin with in the introduction of storage systems in the Uruguayan electricity market. If afterwards, inefficiencies are detected a new activity can be defined as in the UK.

B. Batteries property and operation

It is generally accepted that it is desirable to consider storage systems as actors of the electricity markets, limiting the participations of distribution companies on their property and operation. However, they should be allowed to provide services to the grid, as they are able to do so. What needs to be regulated then, is the way they are paid for these services in order to defend competition in the market. In this respect, what the FERC proposes is that they only recover from regulated tariffs the fraction corresponding to the provision of auxiliary services; the rest must be recovered in the market. Considering that in Uruguay the structure of the electricity market follows in practice a model of "Single Buyer" efficiency is achieved first by an adequate planning and then by assuring that the entry process is competitive. This may be done with open, transparent and competitive biddings.

C. *Participation in electricity markets*

Most electricity markets have three well defined markets: energy, capacity and auxiliary services. However, there exist some other services that are not considered in any of the markets but could be another revenue source for these systems, e.g. CO_2 emissions reduction, transmission and distribution investment postponement, or reduction in generation curtailment. This may constitute a barrier for storage system deployment as they are prevented of possible revenues sources.

1) *Capacity Market*

The capacity market is the one in charge of assuring the amount of resources in an electric system is enough to supply the energy demanded during peak hours. Not every market is open to the participation of storage systems in capacity markets, because they doubt on their ability to provide firm capacity, and those that allow their participation usually establish some requirements that constitute barriers to their deployment. The most restrictive one is that payments in this market usually have a fraction corresponding to performance, which defines a period in which the system must deliver the energy it has compromised. For instance, CAISO[3] requires that when required a system in the capacity market must deliver its energy during 4 hours and for three consecutive days. This may be difficult to achieve for a storage system as they usually have limited capacities. On the other hand, the requirements on capacity markets are of outmost importance in order to warranty a reliable operation of the grid. However, there are some solutions that allow storage system participate in capacity markets without affecting its reliability. One of these, known as de-rate, permits that storage system offer a lower capacity, and not its nominal one, in order to satisfy the requirements. With this measure, supported by the FERC, an asset of 10 MW/20MWh could offer 5 MWh in a market which demands a minimum of 4 hours of continuous operation when required. Without this solution it could not participate in this market, although the asset has the ability of providing 5 MWh reliably during the time required. Another measure, known as aggregation, allows different resources to associate between each other when bidding. This is already implemented in PJM.

2) *Auxiliary Services Market*

The auxiliary services market is the market in which the services needed for the correct functioning of the grid are exchanged. These include voltage and frequency regulation or the black start of the system, among others. Usually, this market requires rapid response. This is why, storage systems are ideal to provide auxiliary services to the grid, particularly frequency regulation. However, there exists some barriers that can prevent an efficient development of these resources in the market. To begin with, many markets do not have a defined auxiliary services market. This decreases storage systems' competitive capacity as they cannot access this revenue source.

Moreover, the lack of incentives on performance is another barrier to storage systems. Nevertheless, recently some markets started to incorporate some kind of incentives in this market. For instance, PJM created two signals for frequency response, a rapid and a slow one, in order to accomplish FERC's Order 755 [12]. The addition of this rapid signal increased the regulation service prices, making storage systems profitable and thus increasing their presence in the market rapidly. By 2017 the installed capacity in batteries reached 300 MW. However, this rapid increase led to a reduction in the market price, reflecting the small capacity of this market. Although it is a way by which storage systems may become competitive in the market, their major potential is in energy and capacity markets.

Finally, a third barrier is the way prices are fixed in these markets. Normally, they are calculated as the opportunity cost of the generator when reserving its capacity from the energy market in order to provide an auxiliary service. The problem of storage systems is that if they are designed to provide only auxiliary services, they do not have associated an opportunity cost. Therefore, if there are enough resources to satisfy the market requirements, the market price collapse to zero. This way of fixing prices does not work for technologies dominated by capital costs. A possible solution to this is that transactions are made through contracts with prices agreed by both sides.

3) *Energy market*

Most energy markets are open to storage system participation. However, their participation is generally low. The main barrier in this case is the lack of participation models that calculate and schedule the optimal dispatch of these resources, taking into account their nature and respecting their limitations. The development of these models has some challenges regarding the complexity and time demand for resolution of the final algorithm. The recent FERC's Order 841 requires all RTO/ISO to develop a participation model to dispatch storage systems in their quality of generation and demand [13]. These models should include the following variables in the bidding parameters: state of charge, charge and discharge maximum power, and maximum and minimum state of charge. The presence of these models should not force storage systems to obey the dispatch that results from these models. As is the case of other generators, they should have the possibility of choosing whether to follow the dispatch or choose their own dispatch. In the first case they should be subject to the same penalties as other generators if they do not follow the dispatch.

In addition, for storage systems, it is desirable that marginal costs are calculated locally and reflect congestions costs of the grid, so as they can benefit from both delivering energy and decongest the grid. It is also recommendable to decrease the transaction time. Although this increases the grid operator's difficulties, for storage systems is crucial, as their business consists of taking advantages of price differences in the market.

[3]CAISO is an independent system operator in USA that serves California.

4) Participation opportunities in the Uruguayan market

If storage systems are classified as generators, they can obtain a payment from delivering energy or providing capacity or auxiliary services to the grid in any of the three markets, as stated before. Usually, the auxiliary service market is the one in which storage systems start appearing as their prices are normally higher. However, this revenue source is not possible in Uruguay as it does not have an auxiliary service market defined. They are conceived as an obligation for generators, which receive a payment for the costs incurred when providing the service. However, storage system can participate is in the energy and capacity market [14]. As explained before, for storage systems participation in the energy market it is important to develop participation models for these resources. Part of this work was to extend the existing model in SimSEE (Section II. A.).

On the other hand, for their participation in the capacity market, their capacity value must be defined. Nowadays, only thermal and hydroelectric generation have this defined in Uruguay's market regulation, so they are the only ones capable of participating in the capacity market. Solar and wind generation cannot participate in this market as they do not have at present a regulatory mechanism defined for calculating their capacity value (although there have been proposals in this sense [15]). The storage capacity value could be calculated as the capacity value as generator, discounting eventually the capacity used as demand for charging if occurring during the same computing period. However, if storage demand is limited to valley hours, that used capacity for charging goes to zero. Then the storage capacity value can be defined, similarly to thermal generation, as their effective power affected by their availability compromised in the "Supply Warranty". The recognition of their capacity value opens an important business for storage systems in the Uruguayan electricity market, particularly if they associate with solar or wind generation, two resources with a considerable presence in the country's generation matrix.

Finally, another business opportunity derived from the analysis of PJM and UK markets is the peak-shaving service. This service that tries to promote a more efficient use of the grid, reducing congestion and losses, could be implemented in Uruguay. It implies modifying the way the system's planning is done, including the concept of grid utilization on it, and not only the backup capacity needed. In order to value this service adequately, the avoided costs in infrastructure, operation, maintenance and fuels should be considered.

IV. Conclusions

The main purpose of this work was to analyze the possibility and perspectives of introducing lithium ion battery storage in the Uruguayan electrical system as a mean of increasing its flexibility. After studying the long-term evolution of battery storage earnings, it was found that systems with lower capacities saw a greater benefit becoming profitable sooner, and so the lower capacity was the one considered in the system expansion plan. This determined that a lithium ion battery of 80MWh/20MW should be installed in 2039. The resulting operation in this year, compared with the cases without batteries, saw a reduction in the energy not delivered to the system, the system's marginal cost and in CO_2 emissions (because of the decrease in thermal generation). Moreover, it was found that the degradation model of the battery should be taken into account. If not, the resulting operation of the system is not viable. On average, a battery will earn 2.21 MUSD for operating in the electricity market in 2039, while its investment cost would be 13 MUSD (i.e. payback period equal to 5.88). Finally, as a result of the regulatory analysis of PJM and UK markets it was concluded that the best classification for these systems would be as generators and so they should be part of the competitive market. Two barriers were identified: the need to define their capacity value and to develop adequate participation models for them. An additional business case was recognized too: peak-shaving service. If barriers are removed and new opportunities are developed batteries could become viable before.

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