PLANNING-ORIENTED YEARLY SIMULATION OF ENERGY STORAGE OPERATION IN DISTRIBUTION SYSTEM FOR PROFIT MAXIMIZATION, VOLTAGE REGULATION AND RESERVE PROVISIONNING

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ABSTRACT

The connection of generation units at the distribution level is expected to increase significantly in the future. This phenomenon will have impacts on the planning and operation of the electric system, both at the local (e.g. appearance of reverse power flows) and global (e.g. modification of the supply-demand equilibrium and of the reserve provisioning capabilities) level. In this context, storage devices are increasingly seen as a possible way to mitigate these impacts, with the caveat –compared to alternative solutions- that their versatility comes with high investment costs. Consequently, it is of the utmost importance to make sure that the full capabilities of these storage devices are put to use. Following this line of thought, this paper presents an algorithm suitable for planning purposes that simulates the yearly operation of distributed energy storage units connected at the medium voltage level to maximize the profit drawn from market operation while respecting voltage and reserve requirement constraints.

INTRODUCTION

In order to ensure the sustainability of electric power system, the share of renewable energies in the production mix will increase in the future. For example, the European Union has set goals for its member states in order to attain a 20% share of renewable energy in its final energy consumption by 2020. This target will be partially met by integrating significant amounts of dispersed renewable energy generators (mainly photovoltaic (PV) and wind power) to the distribution grid. These developments will have considerable impact on the design and operation of the electric system, both at the national and local level, some of which are detailed in the remainder of this introduction. The rest of this paper is organized as follows: first, we will outline the potential applications for storage in this context and how they are modelled, then we will present the methodology applied to solve the resulting optimization problem and end by applying it to a case study and discussing the influence of relevant parameters.

Impacts at the global level

The production side of current electric systems consists in a set of base, intermediate and peak load power plants that is optimal considering the load pattern –and its expected evolution- of the area served. Due to their inherent non-dispatchable nature, wind and PV power can be essentially considered, for this purpose, as negative loads. Consequently, a massive development of such production means will entail a change in the optimal distribution between base, intermediate and peak load power plants, as the resulting net load pattern will be different, and probably more variable, than the existing one. In a liberalized electricity market, this translates into a modification of prices patterns, consisting mainly in lowering prices when non-dispatchable generation levels are high and load levels are low. Taken even further, it can lead to the appearance of negative prices on the spot market.

Spinning reserves are used by system operators to compensate for unpredictable imbalances between supply and demand that can be caused by errors in load forecasting or unplanned outages of generation units. Thus, the massive introduction of non-dispatchable renewable generation units will have an impact on reserve requirement calculation, as the uncertainty on their forecasting is likely to have different characteristics from that of the load. However, it is not yet clear if this will translate into an increase in reserve requirements compared to the traditional rule of using the power generated by the largest unit connected to the grid (see [1] and [2] for contrasting results). What is clear nonetheless is that the replacement of conventional generators by non-dispatchable ones –who are unable to provide spinning reserves in their current operation mode- will induce a change in how reserves are provisioned, either by forcing conventional generators to operate further from their optimal set-points or by resorting to alternatives solutions.

Impacts at the local level

Traditionally, the distribution system has been designed to deliver low-voltage electricity to end-users from centralized power plants connected to the transmission system. It is thus operated under the assumption of unidirectional power flows. The integration of distributed energy sources challenges this assumption since, at high penetration level, it is possible that local generation will surpass local load. The first issue created by these new operating conditions concerns voltage levels. Indeed, current distribution systems have been designed to take full advantage of the permissible voltage range by setting the voltage near the upper limit at the substation and selecting line characteristics that ensure the voltage at the end of the feeder in peak load conditions is still above the lower threshold, while minimizing their cost. The consequence is that, in case of a reverse power flow, it is possible to encounter upper-limit voltage violation even if the magnitude of the reverse power flow is significantly lower than that of the expected peak load [3].

THE POTENTIAL ROLE OF STORAGE IN THIS CONTEXT

Storage is often considered, among other alternatives, as a natural candidate to accompany a significant development of intermittent energy sources (see, for example, [4]). But let's not forget that storage means are already today an integral part of some electric systems. For example, in France, 5 GW of pumped hydro are in operation, mainly to accommodate for a large inflexible nuclear generation fleet and provide ancillary services. For an exhaustive account of the roles that storage devices can play in an electric system, please refer to [5].

In the introduction, we have outlined some of the excepted impacts on the electric system of a shift to intermittent renewable energy sources. The objective of this section is to present how storage devices could help mitigate these and how to model such applications. Henceforth, we will operate under the assumption of the existence of a deregulated electricity market and an Active Distribution Network, as outlined in [6]. In particular, we suppose that the DSO has the possibility to control active and reactive power from distributed storage and generation means and has access to the relevant network physical quantities through a suitable ICT infrastructure. Furthermore, the DSO is responsible for the local supply-demand equilibrium downstream of the substation considered and is able to participate in electricity market where it is a price taker.

Energy Time-Shift

The first impact outlined in the introduction is the modification of the supply-demand equilibrium. If we assume that market prices are a relevant indicator of the state of the supply-demand equilibrium, an operator using a storage device to maximize its profit on the market by buying at low prices and selling at high ones (an application sometimes referred to as "price arbitrage" or "energy arbitrage", as in [7]) will take part in the mitigation of such an impact.

As in [7], we adopt a simplified model for energy storage devices, taking in account maximum power for charge and discharge, energy capacity and efficiency. In this light, the energy time-shift application can be modelled by the following set of equations :

$$\min \sum_{t \in T} C_{Market}^{t} \times P_{Market}^{t} \quad (1)$$

$$\forall t \in T \quad P_{Market}^{t} = P_{Loss}^{t} + \sum_{k \in K} P_{Load,k}^{t} - P_{RE,k}^{t} - P_{st,k}^{t} \quad (2)$$

$$\forall t \in T, k \in K, SOC_{k}^{t} = \sum_{p=1}^{t} \left(\eta_{ch,k} \times P_{ch,k}^{p} - \frac{P_{dis,k}^{p}}{\eta_{dis,k}} \right) + SOC_{k}^{init} \quad (3)$$

$$\forall t \in T, k \in K, \quad 0 \le P_{ch,k}^{t} \le P_{ch,k}^{\max}, \quad 0 \le P_{dis,k}^{t} \le P_{dis,k}^{\max} \quad (4)$$

$$\forall t \in T, k \in K, \quad 0 \le SOC_{k}^{t} \le SOC_{k}^{\max} \quad (5)$$

$$\forall t \in T, \quad -P_{Market}^{\max} \le P_{Market}^{t} \le P_{Market}^{\max} \quad (6)$$

where T is the set of time steps considered, K is the set of buses considered, C_{Market}^{t} is the market price forecast, P_{Market}^{t} is the algebraic power transacted on the market (equivalent here to the power transiting through the substation and positive when buying) during time step t, P_{Loss}^{t} are the aggregate network losses downstream of the substation, $P_{Load,k}^{t}, P_{RE,k}^{t}, P_{ch,k}^{t}, P_{dis,k}^{t}, P_{s,k}^{t}, SOC_{k}^{t}$ are, respectively, the load, the renewable energy power injected, the charge, discharge, algebraic power injected in the grid and state-of-charge of the storage device, at bus k during time step t. $SOC_{k}^{\max}$, $P_{ch,k}^{\max}$, $P_{dis,k}^{\max}$ are the energy capacity, maximal discharge power and maximal charge power of the storage device connected at bus k, while $P_{Market}^{\max}$ is the maximal power transacted on the market.

(1) represents the minimization of the cost incurred to the DSO, (2) expresses the local supply-demand equilibrium for which the DSO is responsible, (3) models the evolution of the storage device state-of-charge while (4), (5) and (6) deal with technical limitations.

Spinning Reserve Provisioning

A potential fair solution –in terms of reducing negative externalities- to the second impact mentioned in the introduction would be to devise a mechanism requiring non-dispatchable energy producers to provide spinning reserves as a function of the power produced, so that the diminished reserve provisioning capabilities of conventional generating units are compensated for at the system level. Hereafter, we assume that such a mechanism exists, that the reserve requirement is proportional to the power produced and that it is fulfilled by the storage devices deployed in the system considered. From a modeling perspective, this translates into the following set of equations :

$$\forall t \in T \quad \sum_{k \in K} P_{dis,k}^{\max} - \left(P_{dis,k}^{t} - P_{ch,k}^{t} \right) \ge \alpha_{UpReserve} \times \sum_{k \in K} P_{RE,k}^{t} \quad (7)$$

$$\forall t \in T \quad \sum_{k \in K} P_{ch,k}^{\max} - \left(P_{ch,k}^{t} - P_{dis,k}^{t} \right) \ge \alpha_{DownReserve} \times \sum_{k \in K} P_{RE,k}^{t} \quad (8)$$

where $\alpha_{UpReserve}$ and $\alpha_{DownReserve}$ are the proportionality coefficient defining the reserve requirements.

Voltage Control

Henceforth, we assume that the storage devices and renewable energy units are connected to the grid through an Advanced Power Electronic Interface (APEI), as defined in [6], and that the substation transformer is equipped with an On-Load Tap Changer (OLTC), for which we use a simplified continuous model. We also assume that the grid downstream of the substation has a radial structure, which allows us to use the set of network equations defined in [8]. Consequently, we model this application with the following equations $\forall t \in T, j \in K,$:

$$P_j^t - \sum_{kk \in KK_j, kl \in KL_j} R_{kl} \times \frac{P_{kk}^{t\ 2} + Q_{kk}^{t\ 2}}{U_{kk}^t} - \sum_{kk \in KK_j} P_{kk}^t = P_{NetLoad,j}^t \quad (9)$$

$$Q_j^t - \sum_{kk \in KK_j, kl \in KL_j} X_{kl} \times \frac{P_{kk}^{t\ 2} + Q_{kk}^{t\ 2}}{U_{kk}^t} - \sum_{kk \in KK_j} Q_{kk}^t = Q_{NetLoad,j}^t \quad (10)$$

$$U_j^{t\,2} + 2\left(P_j^t \times R_j + Q_j^t \times X_j - \frac{U_i^t}{2} \right) \times U_j^t + Z_j^{\ 2} \times S_j^{t\,2} = 0 \quad (11)$$

$$U_j^t = V_j^{t\,2}, \quad Z_l^{\ 2} = R_l^{\ 2} + X_l^{\ 2}, \quad S_j^{t\ 2} = P_j^{t\,2} + Q_j^{t\,2} \quad (12)$$

$$P_{NetLoad,j}^t = P_{Load,j}^t - P_{RE,j}^t - P_{st,j}^t \quad (13)$$

$$Q_{NetLoad,j}^t = Q_{Load,j}^t - Q_{RE,j}^t - Q_{st,j}^t \quad (14)$$

$$V^{\min} \le V_j^t \le V^{\max}, \quad V_{OLTC}^{\min} \le V_{OLTC}^t \le V_{OLTC}^{\max} \quad (15)$$

$$P_{st,k}^{t\ 2} + Q_{st,k}^{t\ 2} \le S_{st}^{\max 2}, \quad P_{RE,k}^{t\ 2} + Q_{RE,k}^{t\ 2} \le S_{RE}^{\max 2}, \quad (16)$$

where P_j^t and Q_j^t are, respectively, the active and reactive power entering node j from the upstream node i, V_j^t and V_{OLTC}^t the voltage magnitude, respectively, at node j and downstream of the substation transformer, during time step t. $Q_{Load,j}^t$ is the reactive load, $Q_{RE,j}^t$ and $Q_{st,j}^t$ are the algebraic reactive powers injected by the APEI of, respectively, the renewable energy generating unit and the storage unit, of which $S_{RE}^{\max}$ and $S_{st}^{\max}$ are the maximal apparent powers. $V^{\min}$ and $V^{\max}$ define the range of permissible voltages in the network considered, while $V_{OLTC}^{\min}$ and $V_{OLTC}^{\max}$ mark the boundaries of the attainable voltage downstream of the substation.

METHODOLOGY

The optimization problem defined by equations (1) to (16) is non-linear, due to the presence of quadratic terms, and non-convex because of the terms $\frac{P_{kk}^{t\ 2} + Q_{kk}^{t\ 2}}{U_{kk}^t}$ in equations (9) and (10). The control variables are the vectors of active and reactive power injected by the storage devices, the vectors of reactive power injected by the renewable energy APEI and the vector of voltage downstream of the OLTC-equipped transformer. (3) introduces a time-coupling constraints that prevents us from solving the problem time step by time step. Consequently, if we want to solve it for a year with one-hour time steps, the dimensionality of the problem becomes very high. These combined characteristics make the problem difficult to solve, especially in a context of distribution system planning, for which a high number of varying instances have to be solved (see, for example, [9]) in order to attain an optimal planning. Hereafter, we present the simplification adopted to find a satisfactory compromise between optimality and computational time.

Partial time-decoupling

As explained before, the coupling between the time steps is induced by the evolution of the state-of-charge of the storage units. Moreover, these state-of-charges are dependent only from the active powers produced by the storage devices, which are mainly driven by the evolution of market prices. As these market prices often present strong daily and weekly pattern, we can guess that there may be a time horizon above which no significant additional benefits can be captured. We verify this by solving (1) to (8) for a year and one-hour time steps and for various time horizons, while measuring the computation time. Results are presented in the table below and lead us to choose a 7-day time horizon.

Time Horizon (in days)	Cost variation (in %)	Computation time (in seconds)
1	0	26
7	-2.02	70
70	-2.11	709
140	-2.11	2614

Table 1 : Evolution of optimality and computation time as a function of the time horizon

Scheduling and voltage control decoupling

The observation of (1) shows that only active powers have an influence on the objective function, while reactive powers only play a role when voltage magnitudes are inadequate. For the remainder, we define three types of time steps: a time step is deemed non-critical if the network equations and constraints are not active, semi-critical if they are active but not binding and critical if they are. From [3], we know that, even at high levels of penetration of photovoltaic generators, voltage limit violations are infrequent events. To further this claim in the presence of storage devices, we execute simulations on the 69-bus medium-voltage network used in [8] for various levels of photovoltaic and storage penetration (defined as the ratio between the maximal apparent power of PV and storage connected at a given node and its annual maximal load) and compute the numbers of semi-critical and critical time steps.

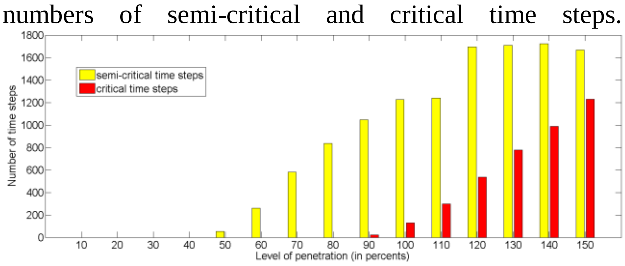

Figure 1 : number of critical and semi-critical time steps

We thus observe that, even at unconventionally high levels of penetration, the number of critical time steps remains relatively low. This allows us to separate the complete problem in a linear multi-stage master problem of scheduling active powers defined by (1) to (8), for which we further reduce the number of variables by aggregating the storage units with the same efficiency and discharge duration, and a single-stage non-linear non-convex problem defined by (9) to (16) to which we add the objective of minimizing the quadratic deviation from the master problem results. We then recombine both results to find a solution respecting the constraints while being close enough to the objective function optimal value (an upper bound on the loss of optimality induced can be evaluated, as the results of the master problem give us a lower bound on the cost function).

CASE STUDY

We apply this methodology to a case study consisting in the 69-bus network mentioned above, with residential-type loads connected at each node and scaled so that the annual maximal load is equal to the loads used in [8]. Reactive loads are defined, so that the power factor remains constant and equal to the one used in [8]. We study the impact of the deployment of PV generators and storage units by making the number of nodes equipped (N) and the level of penetration, as defined above, (L) vary. For each number of nodes equipped, the nodes are chosen in increasing order of driving-point resistance. Below, we present some of the results obtained.

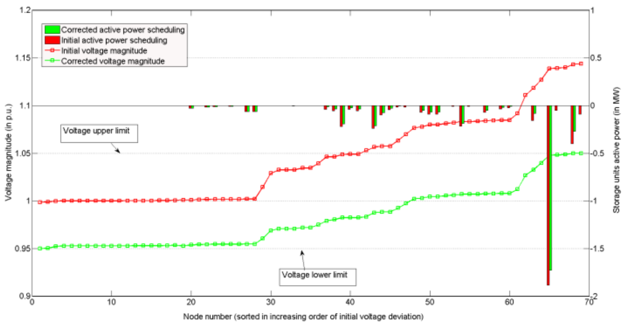

Figure 2 : Influence of voltage limit violations on active powers for a critical time step

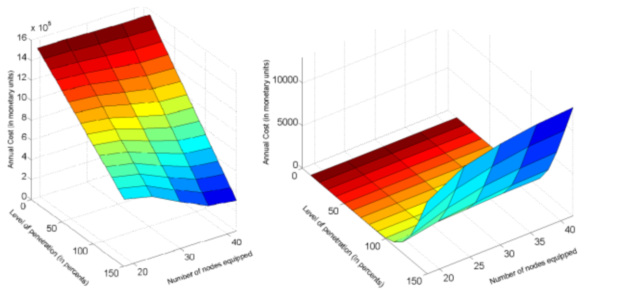

Figure 3 : (a)Total annual scheduling cost and (b)cost of voltage control for various deployment scenarios

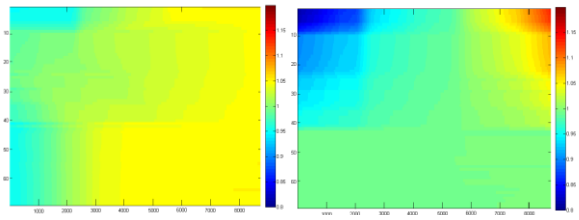

Figure 4 : (a) Voltage magnitude by node and by time step, sorted in increasing order of voltage magnitude

CONCLUSION

First, we have outlined some of the opportunities for storage units presented by the expected deployment of renewable energy generators in the distribution system. Then, we have modelled these applications in the form of a non-convex non-linear optimization problem that we separate in a master and a slave problem in order to make it tractable. We end by applying in to case study, and verify that the results are coherent with what was expected. Future research will be conducted along three axis : improving the computational efficiency of the algorithm, adding other applications of storage to the model and integrating it in an exhaustive distribution system planning process.

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