FLEXIBILITY MODEL OF INTEGRATED ENERGY SOURCES FOR THE STRATEGIC PLANNING OF DISTRIBUTION NETWORKS

Gianni CELLI
University of Cagliari – Italy
celli@diee.unica.it

Fabrizio PILO
University of Cagliari – Italy
pilo@diee.unica.it

Simona RUGGERI
University of Cagliari – Italy
simona.ruggeri@diee.unica.it

ABSTRACT

The evolution of the European energy sector towards a decarbonized economy will provide a new impulse to the renewable energy exploitation. The expected strong impact on the power system can be positively faced only with a huge amount of energy flexibility. Because a large share of this flexibility is potentially associated to a multitude of small energy resources sited on LV distribution networks, which can hardly contribute singularly to the system operation, aggregations of these resources, managed as single entities, will characterise the scenario of the future Smart Distribution Networks. The paper presents a flexibility model of this aggregation, with particular attention to the representation of Demand Response. Moreover, a simple optimization tool has been developed to show the potential benefits these energy resources aggregations can bring to solve network contingencies and whose a strategic planning of distribution networks has to take into account.

INTRODUCTION

The European energy policies in the last decades have been mainly oriented towards a progressive decarbonisation of the energy sector, solicited by the various international climate agreements (like the Kyoto protocol in 1997 and the Paris agreement in 2015) and by the need to decrease the EU's energy dependence from fossil fuel imports. Recently, European Parliament has approved with amendments the "Clean Energy for all European" package (also know as Winter Package), fixing new binding targets by 2030: 35% of improvement in energy efficiency, 35% share of energy consumption from renewables, and 12% share of energy from renewable sources in transport [1]. For sure, this EU political framework and the foreseen strong increment of renewable plants will affect the functioning of internal electricity markets and of the electric infrastructures (both transmission and distribution grids), posing new challenges to be faced.

Distribution system will be particularly stressed by this new phase, due to the already existing medium-high penetration of Renewable Energy Sources (RESs), connected in the last ten years under the previous 2020 European energy package. Consequently, the hosting capacity of the distribution networks with passive management will be more and more frequently overcome in the near future, requiring unsustainable grid investments or the definitive acceptance of the active operation and Smart Grid concepts. Their full application needs a huge amount of flexibility, i.e. the possibility for the majority of the Distributed Energy Resources (DERs) to be directly controlled by the Distribution System Operator (DSO) or to be available for adapting their normal operation to the DSO requests. A large share of this flexibility is potentially associated to a multitude of small energy resources sited on LV distribution networks (renewable generators, electric vehicles, energy storage devices). If considered singularly, these resources are often too small to contribute in the system operation, but controlled as an aggregation (physically located near each other within a small private network as a Microgrid or spread farther on the distribution grid like a Virtual Power Plant) they can provide the required flexibility for the achievement of the future ambitious target of decarbonising the European power sector. Moreover, the aggregation of all these resources allows the exploitation of Demand Response (DR) programmes that hardly can be efficiently activated alone. Obviously, a deep transformation of the current regulatory framework is required, with the opening of the Ancillary Services Market to these new resources and the activation of local flexibility markets where the DSO shall procure the needed services to support the efficient and secure operation of the distribution system. This vision is already included in the Winter Package that also favours the formation of Local Energy Communities (LECs) among producers, consumers and prosumers (comprehensive also of storage devices).

The paper follows this innovation and presents a flexibility model of an aggregation of distributed energy resources, which includes distributed generation (DG), storage devices and Demand Response. Particularly, the representation of the consumers' behaviour involved in DR programmes has been investigated, because part or all of the curtailed demand may be recovered at a later period (payback effect), causing unforeseen imbalances in the system [2]. Then, an optimization tool has been developed, based on a simple Linear Programming approach, to show the potential benefits these DERs can bring to solve network contingencies and of which a strategic planning of distribution networks has to consider among the available planning solutions.

DEMAND RESPONSE

The overall technical area focused on the demand flexibility and its potential as a source of services has been identified by the CIGRE WGs C6.11 and C6.19 with the term Demand Side Integration (DSI) [3]. The DSI actions are classified into long-term measures (Energy Efficiency and Strategic Load Growth) and short-term or on-line programmes (Demand Response – DR). Depending on the specific timescale of the response, services associated to load flexibility can be grouped into four categories [4]:

- *Shape* captures DSI actions that remodels the load profile through relatively long-run price responses (time-of-use and critical peak pricing rates) or on behavioural campaigns with advance notice of months to days (goals mostly related to strategic planning);
- *Shift* represents DR that encourage the movement of energy consumption from times of high demand to times with surplus of renewable generation. It involves dispatchable resources able to respond to a signal sent many hours in advance or a day ahead (e.g. rescheduling EV charging fleets or pre-cooling with HVAC units);
- *Shed* describes loads that can occasionally be curtailed to provide peak capacity and support the system in emergency or contingency events (interruptible processes, advanced lighting controls, air-conditioners, etc.);
- *Shimmy* involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour (in this case a behind-the-meter storage device is required).

Within the goal of modelling the active management of the electric distribution network as a planning alternative to the traditional grid refurbishment, the paper is focussed on the representation and the optimal control of the third category of DR services that, joined with the management of storage devices and renewable generators, provides DSO with the needed flexibility to solve contingencies or support the network during emergency configurations.

DR programme is typically implemented by an aggregator that acts like an intermediary between groups of end-users (often small) and the DSO, by aggregating the flexibility of each consumer and selling it when requested [6]. Moreover, it manages the provision of DR services by reducing the uncertainties of the end-users' response (i.e. involving them in rotation) and limiting possible negative effects.

Payback effect

In the curtailment of a peak demand, often the loads involved in the DR action are not simply switched off but they are shifted after the end of the DR signal. A compressor in an industrial process or a dishwasher for a residential load are examples of devices whose starting can be delayed in response to an external request and whose consumption is not avoided but postponed. The increase of the demand after a peak shaving action (payback effect) may cause unbalances to the electricity market and new contingencies to the electric distribution network.

The aggregator is the only player that can make accurate estimations of the expected payback, because it normally knows the assortment and the behavior of its portfolio of consumers. The aggregator uses this knowledge to provide payback information to the DSO (together with the available power that can be controlled), in order to allow technical verifications. Or, it is exploited to reduce the energy payback in accordance to limits provided by the DSO (together with the DR request), by avoiding the simultaneous reconnection of all the curtailed loads or by gradually recovering, if possible, their consumption (e.g. heating and cooling system with thermal inertia).

In the paper, the first approach is assumed: DSO receives from aggregators the information about the amount of curtailable demand and of the relative payback effects. In this way, the DSO is able to optimize the management of the available resources or the request of services from the local flexibility market.

DR Modelling

The behavior of the consumers' aggregation has been represented considering both its flexibility (percentage of the total demand that can be used for DR actions) and its payback characteristics (i.e. when and how much of the energy curtailed is recovered). If the consumers' response is assumed linear and time-invariant, the simplest way to model the DR is with a Finite Impulse Response filter, characterized by a memory of N intervals. In general, the filter's output at the k^{th} interval of the day, $y(k)$, is computed as a weighted sum of present, $x(k)$, and past, $x(k-n)$, values of the filter input:

$$\begin{aligned} y(k) &= \sum_{n=0}^{N} f_n \cdot x(k-n) = \\ &= f_0 \cdot x(k) + f_1 \cdot x(k-1) + \cdots + f_N \cdot x(k-N) \end{aligned} \tag{1}$$

where f_n is the n^{th} filter coefficient of weight. The application of this general model to the DR gives:

$$\Delta P_{DR}(k) = f_0 \cdot DR(k) + \sum_{n=1}^{N} f_n \cdot DR(k-n) \tag{2}$$

where

- $DR(k)$ is the requested amount of power curtailment from the DSO at the k^{th} interval,
- $\Delta P_{DR}(k)$ is the actual response of the consumers' aggregation to the DR request at the k^{th} interval, taking into account also the payback effects due to the DR actions in the previous intervals,
- f_0 is the global level of willingness of the consumers' aggregation to accept the request to curtail the consumption, and it is dependent on the

amount of curtailable demand provided by the aggregator (DR^{max}) and the curtailment requested by the DSO: if the first is greater or equal to the second, then $f_0 = 1$, otherwise $f_0 < 1$ (their ratio),

- $f_1 \ldots f_N$ are used to model the payback effect. If the curtailed energy is recovered uniformly along Δt_{rec} intervals, they can be expressed as:

$$f_n = -\frac{\%rec}{\Delta t_{rec}} \cdot f_0 \tag{3}$$

where $\%rec$ is the percentage of actual curtailed demand, $f_0 \cdot DR(k\text{-}n)$, to be recovered. The negative sign is needed to correctly represent the payback effect. If the recovering starts Δt_{delay} intervals after the DR request, the corresponding filter coefficients $f_1 \cdots f_{\Delta t_{delay}}$ are null and $N = \Delta t_{delay} + \Delta t_{rec}$.

OPTIMAL OPERATION OF DER

As stated before, for the correct planning of a Smart Distribution Network (SDN) the DSO needs to verify if the management of the available DERs are sufficient to solve possible contingencies and to quantify how much cost this flexibility. In order to achieve these goals, a classic OPF problem has to be solved, which minimizes the overall active management cost, subject to technical constraints related to network and resources operation.

Thank to the validity of the power system non-linearity's approximation for a distribution network, a linear programming approach has been chosen. The cost-function to minimize (C_T) is the weighted sum of the flexibility services provided by all accessible DER: active power injection (P_{dis}) or absorption (P_{ch}) from Energy Storage Systems (ESSs), active power curtailment (GC) and reactive power control (Q) from DG, and demand peak shaving from DR actions.

$$\begin{aligned} \min C_T = \sum_{t=1}^{T} \Bigg[& \sum_{d=1}^{N_{DR}} c_{DR} \cdot DR_d(t) + \sum_{g=1}^{N_{DG}} \left(c_P \cdot GC_g(t) + c_Q \cdot Q_g(t) \right) + \\ & + \sum_{s=1}^{N_{ESS}} c_{ESS} \cdot \left(P_{dis,s}(t) + P_{ch,s}(t) \right) \Bigg] \end{aligned} \tag{4}$$

subject to resources' constraints:

$$0 \le DR_d(t) \le DR_d^{\max} \quad \text{for } d = 1, \cdots, N_{DR} \text{ and } t = 1, \cdots, T \tag{5}$$

$$0 \le GC_g(t) \le P_g^{DG}(t) \quad \text{for } g = 1, \cdots, N_{DG} \text{ and } t = 1, \cdots, T \tag{6}$$

$$-Q_g^{\min} \le Q_g(t) \le Q_g^{\max} \quad \text{for } g = 1, \cdots, N_{DG} \text{ and } t = 1, \cdots, T \tag{7}$$

$$\begin{aligned} 0 \le P_{dis,s}(t) \le P_{n,s}^{ESS} \\ 0 \le P_{ch,s}(t) \le P_{n,s}^{ESS} \end{aligned} \quad \text{for } s = 1, \cdots, N_{ESS} \text{ and } t = 1, \cdots, T \tag{8}$$

$$0 \le SoC_s(1) + \sum_{h=1}^{t} \left[P_{ch,s}(h) - P_{dis,s}(h) \right] \le C_{n,s}^{ESS} \quad \begin{aligned} s &= 1, \cdots, N_{ESS} \\ t &= 1, \cdots, T \end{aligned} \tag{9}$$

and network's constraints:

$$\begin{gathered} V_{\min} \le V_j(t) + \Delta V_j^{DR}(t) + \Delta V_j^{DG}(t) + \Delta V_j^{ESS}(t) \le V_{\max} \\ \text{with} \\ \Delta V_j^{DR}(t) = \sum_{d=1}^{N_{DR}} \left(\frac{\Delta V}{\Delta P} \right)_{j,d} \cdot \left[f_0^d \cdot DR_d(t) + \sum_{n=1}^{N} f_n^d \cdot DR_d(t-n) \right] \\ \Delta V_j^{DG}(t) = \sum_{g=1}^{N_{DG}} \left[-\left(\frac{\Delta V}{\Delta P} \right)_{j,g} \cdot GC_g(t) + \left(\frac{\Delta V}{\Delta Q} \right)_{j,g} \cdot Q_g(t) \right] \\ \Delta V_j^{ESS}(t) = \sum_{s=1}^{N_{ESS}} \left(\frac{\Delta V}{\Delta P} \right)_{j,s} \cdot \left[P_{dis,s}(t) - P_{ch,s}(t) \right] \\ \text{for} \\ j = 1, \cdots, N_{DN} \quad t = 1, \cdots, T \end{gathered} \tag{10}$$

where N_{DR}, N_{DG}, and N_{ESS} are the number of secondary substations respectively involved in the DR programme, with generators connected and with storage devices installed, N_{DN} is the total number of secondary substations in the distribution network, V_{min} and V_{max} are the minimum and maximum nodal voltage constraints, c_{DR}, c_P, c_Q, and c_{ESS} are the unitary costs of the flexibility services, $P_g^{DG}(t)$ is the active power produced by the g^{th} generator in the t^{th} interval, Q_g^{min} and Q_g^{max} are the reactive power rates of the g^{th} generator, $P_{n,s}^{ESS}$ and $C_{n,s}^{ESS}$ are the nominal power and capacity of the s^{th} ESS, $SoC_s(1)$ is the State of Charge of the s^{th} ESS at the beginning of the first interval, and T is the total number of intervals considered for the optimization. The factors $(\Delta V/\Delta P)$ are the sensitivity coefficients of each nodal voltage with respect to any flexibility service and they are assessed by means of load flow calculations.

The simultaneous consideration of more intervals for the optimization is required by the need to represent the payback effect with the DR actions and to model correctly the charge/discharge limitations of the ESS along the day. Typically, for planning studies of a SDN, the standard interval is one hour and T can be the whole day (24 hours), when the optimization tool is applied to check the normal operating conditions of the SDN, or the duration of an emergency network configuration used after the disconnection of a faulted element.

In the mathematical formulation of the optimization problem it has been explicitly represented only the nodal voltage constraints, but a similar formulation is used also for the ampacity constraints of network lines. Finally, the presence of the constraint (5) allows overcoming the non-linearity in the definition of the filter coefficient f_0, because it forces f_0 to be always equal to 1.

RESULTS AND DISCUSSION

The model proposed has been tested considering a portion of the representative Italian rural network available from the ATLANTIDE project (Figure 1).

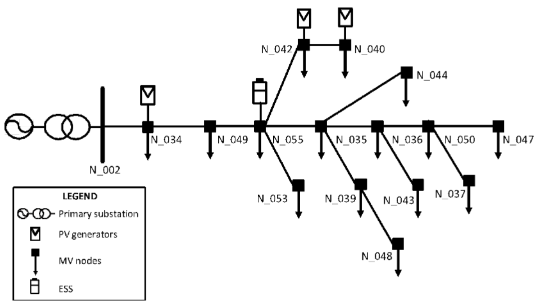

Figure 1. The analysed network

The feeder is characterised by long overhead lines (maximum length 17 km).

There are 15 MV nodes prevanlently agricultural (AGR), MV customers (RMV) and residential (RLV), with low consumptions. The total load installed is 3.8 MW. 3 PV generators are installed (the total power installed is 7 MW). The high presence of generators and the low load demand determine overvoltages during the central hours of the day (between h 12 and h 13), while during the evening, the increased demand and the long lines cause undervoltages (from h 18 to h 22). The nodes which suffer the undervoltages are located at the end of the feeder (N_047, N_037, N_036 and N_043), while those characterised by the highest voltage increase are at the PV generators. A 1MW-4MWh ESS is installed by the DSO in N_055, to support the network operation. The Aggregator can easily solve all the contingencies through the ESS, that absorbs the PV production during the morning and rejects it during the evening peak demand, without curtailing the PV generation or the reactive support from the DG.

If the size of the ESS is reduced (P=0.5 MW E= 3MWh), it is not possible to solve all the contingencies using only the battery, but also the reactive support of the PV generators, and the involvement of customer is needed. It is supposed that all the nodes participate to the DR program, allowing the curtailment of the 50% of their load demand. The RLV customers will recover (%rec) the 80% of their curtailed power in the next 2 hours (Δtrec), while the AGR and the RMV ones will recover (%rec) the 40%.

Due to the long distance between the DG and the nodes (more than 7 km), the reactive support of the DG is very small (a small quantity is injected between h 20 and h 21). Regarding the loads participation, the nodes involved in the optimization are N_037, N_043 and N_047. Nevertheless, these nodes are also the ones with the maximum recovery of the curtailment (the 80% of the curtailed load demand). Such behaviour, if not properly taken into account during the optimisation process, could lead to an unexpected increase of the load demand (as in the case of node N_037, showed in Figure 2 a) green pointed line). Thus, if the payback is considered in the optimisation process the nodes involved are N_050 (AGR type) and N_043 (RLV type). In this case, the node with the highest curtailment is node N_050 that recovers only the 40% (see Figure 2 b), while N_043 curtails a small percentage of load, avoiding further contingency.

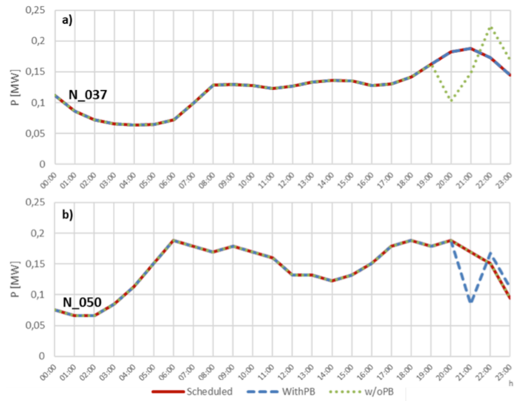

Figure 3. Load demand in nodes N_037 and N_050.

Figure 3 shows the voltage profile of the node with the highest voltage drop (node N_037) when the payback effect (blue dashed line) is considered and not taken into account (green pointed line) in the optimisation.

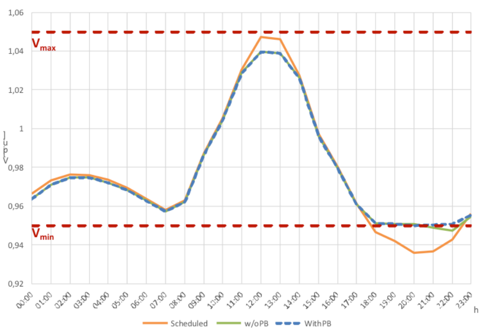

Figure 2. Voltage profile of N_037 before and after the optimisation.

REFERENCES

[1] European Commission, *Clean Energy for all Europeans*, COM (2016) 860 final.

[2] E. A. Martinez Cesena et al., 2015, "Electrical network capacity support from DSR: techno-economic assessment of potential business cases fro small commercial and residential end-users," *Energy Policy Journal*, vol. 82, pp. 222-232.

[3] CIGRE WG C6.19, 2014, *Planning and Optimization Methods for Active Distribution Systems*, Technical Brochure 591.

[4] Lawrence Berkeley National Laboratory, 2016, *2015 California Demand Response Potential Study*, Final Report.

[5] S. Kiliccote et al., 2016, "Characterization of demand response in the commercial, industrial and residential sectors in the United states," *WIREs Energy Environ.*, vol. 5, pp. 288-304.

[6] ADDRESS project (EU programme FP7/2007-2013). Available from: http://www.addressfp7.org

[7] A. Bracale et al., "Analysis of the Italian Distribution System Evolution through Reference Networks", *Proceedings Innovative Smart Grid Technologies* (ISGT), Berlin, 14-17 Oct 2012.