Technical Constraints and Flexibility Management in Smart Grids

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***Abstract*— Technical constraints and flexibility management in smart grids are analyzed using a market based approach. Flexibility services may allow network operators to tackle grid constraints in all timescales, maintaining reliability and quality of service and maximizing integration of distributed energy resources. Here, only short term markets will be considered; consumer and DER flexibility will be used in order to solve the distribution grid constraints (line/transformer overloads or voltage limit violations) in the day-ahead framework. The main contribution of the paper is a proposal of congestion management in smart grids consistent with the wholesale electricity market already in use. The role of the new actors will be highlighted to remark the consequences of regulatory decisions to be taken in the next future.**

***Index Terms*-- Congestion management, DER, Flexibility markets, Smart grids.**

I. Introduction

The power distribution grids are undergoing fundamental changes towards more dynamic and complex structures, due to the integration of distributed generation (DG), prosumers with load-generation behavior, distributed energy storage, new equipment and services, and demand side management (DSM). The topology of the distribution network is being shifted from mostly radial to a more meshed topology with bidirectional power flows. Traditional passive distribution grids are being transformed into smart distribution grids that are active in nature.

Grid operation is aimed at effectively balancing two main objectives a) reliable grid operation and b) low cost of operation. Both the transmission system operator (TSO) and the distribution system operator (DSO) are responsible for "ensuring the long-term ability of the system to meet reasonable demands" for the transmission/distribution of electricity, and "for operating, maintaining and developing under economic conditions secure, reliable and efficient" transmission/distribution systems as stated in Art. 12 and 25 of the Electricity Directive (Directive 2009/72/EC).

Today, DSOs ensure system reliability through three main tasks: network investments, maintenance and reinforcement, voltage control, and load/generation curtailment. With the integration of DER and the development of the smart grid concept, new functionalities for DSOs are required. High penetration of DER, on the one hand, and complex loads like electric vehicles and heat pumps, on the other hand, lead to congestion problems and violated limits in distribution grids. Also the influence of variable RES on the electricity price makes urgent the need for congestion management in the distribution grid, because a high penetration of renewable energy sources weakens the correlation between electricity prices and network demand [1].

Here a simple method for managing technical constrains and flexibility in smart distribution grids is proposed, which is derived from the one followed in the wholesale Spanish electricity market. Different approaches for the solution of technical constrains in distribution grids are discussed first. Then some regulatory issues are highlighted in section III. In section IV the proposal with the sequence of operations and the role of the different actors in the process is explained. In order to test the feasibility of the proposal, a case study is given in section V and conclusions are made in section VI.

II. Solution of Technical Constrains in the Distribution Grid

Transmission system congestion management procedures vary according to the electricity market structure. Though nodal pricing is considered the most efficient model, in Europe, a combination of zonal pricing (market splitting) and counter-trading or re-dispatching is mostly used [2]. Market splitting solves inter-zonal congestions while counter-trading or re-dispatching is used to solve the intra-zonal congestions. This is the practice, for example, of the Iberian market (MIBEL) and the Nordic market (Nord Pool), although there are some differences between them. For example, demand-side does not participate in solving intra-zonal congestions in the Spanish transmission system, but it does in the Finnish system [3].

Several methods have been discussed in the recent years for congestion management of distribution grids. In [1], [4],

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three main strategies are discussed when analyzing congestion caused by EV charging: 1) a distribution grid capacity market, 2) advance capacity allocation, and 3) a dynamic grid tariff. Reference [1] analyses these methods under the assumption of imperfect information, and concludes that further research is needed in order to take into account the uncertainties in electricity prices which are strongly related to imperfect RES forecasts, as well as uncertainties in network load and EV driven schedules. The conclusion of [4] is that there is always a trade-off between complexities, values and risks for the stakeholders.

Most of previous works, however, focus in the demand response and demand control as means to avoid local distribution grid congestions, and different tariff models have been evaluated [5], [6].

Some Key Operations for DSO congestion management in advanced distribution grids are mentioned in [4], being aggregation one of them. Aggregation offers the opportunity to exploit the flexibility potential of smaller customers and allows a better access to the markets. In this context, a new business entity, namely Aggregator, has recently emerged in order to aggregate the flexibilities of demand side and DG, and capturing the business opportunities of providing the service to the system operators [7].

Different approaches have been proposed to manage flexibility, as those considered in the Address and iPower research projects. While Address tries to adapt the architecture to the existing markets, iPower defines a new DSO-market on flexibility services. An overview of both approaches is presented below.

A. Address

Address project [8] is aimed to develop a comprehensive commercial and technical framework for enabling the active participation of domestic and small commercial customers in the power system markets and in the provision of ancillary services. The main actors are the Aggregator (*Commercial Aggregator, CA*) and the DSO (*Technical Aggregator, TA*). The Aggregators are the mediators between consumers and markets. Their role consists in collecting requests and signals coming from the markets and the different power system participants, gathering the consumption flexibilities and offering the services to the interested participants through the markets.

DSOs, as TA, must check the technical feasibility of the Active Demand (AD) products and the overall stability of the power system. Their new role is threefold: 1) Provision of the Flexibility Table (FT) with the maximum and minimum limits of flexibility to prevent violations of the networks constraints; 2) Validation of the AD products to ensure their feasibility; 3) Purchase of AD products to be used for distribution network reinforcement deferral, in case of contingency.

Two basic AD products are identified: Scheduled Re-profiling (SRP) and Conditional Re-Profiling (CRP)[1]. In a SRP the aggregator has the obligation to provide a specified demand modification (reduction or increase) at a given time to the product buyer, whereas with a CRP the aggregator must have the capacity to request a specified demand modification during a given period; the delivery is called upon by the buyer of the product (similar to a reserve service).

The Address project considers other actors with potential interest in purchasing AD products. These are Consumers (or *prosumers* if the consumers have generation and/or storage capabilities), Retailers, Balance Responsible Parties (BRPs) and TSOs.

B. iPower

The iPower project [9] is a Danish national research project focused on the development of intelligent demand-response controls for handling of decentralized power consumption, and integration of DER and RES.

In order to incorporate flexible DERs into the market, and taking into account that the volume in traded flexibility is expected to increase over time, a new trading platform (a Flexibility Clearing House – FLECH) is suggested. FLECH is a new capacity market at distribution level (i.e. for dealing with the trading of CRPs, using Address terminology). The trading for a DSO flexibility service consists of two separate phases: 1) A long-term reservation of capacity to ensure sufficient flexibility in a Capacity Reserve Market; and 2) a short-term activation scheme (closed to the operational hour the DSO will know whether activation of the service is necessary or not) in an Activation Reserve Market.

Actors considered by iPower are Consumers, Aggregators, BRPs, Retailers, DSOs and TSOs, but in iPower only BRPs are allowed to trade at the wholesale markets.

III. Regulatory issues concerning flexibility

Both, Address and iPower projects, point out some important regulatory issues to take into account, among them the coordination TSO-DSO, the risk of malicious behavior from the aggregator, the information management, the placement of imbalance costs and the possible conflicts between existing and new actors, problems arising with more than one aggregator in the regional area of a DSO.

A. Coordination TSO-DSOs

As both, the TSO and DSOs can be users of flexibility services, there is a possibility for conflicting demands on flexibility and coordination is necessary among TSO and DSOs taking into account their own responsibilities and different needs and constraints of regional and local networks. Market rules should be clear on how to handle these cases and the coordination between SOs (TSO and DSOs) must be considered by regulators.

B. Risk of malicious behavior from the aggregator

Without any market rules, the aggregators are able to produce conflicts that they afterwards should be paid to solve. For example, knowing the weak points of a network might encourage the CA to intentionally create congestions to increase its profit. This malicious behavior can be avoided with a good coordination among actors, imposing, e.g. that CAs can only serve DER flexibility to one party at a time.

[1] There is a third AD product which is considered here as a variation of CRP: Bi-directional Conditional Re-Profiling (CRP-2), if the specified demand modification is in a bi-directional range [-y, x] MW, including both demand increase and decrease.

C. *Information management*

Nowadays, the DSOs/TSOs have the knowledge of their grid and measurements, while the retailers have commercial information of the consumers. But in the smart grid context, new requirements for information exchange appear which give rise to confidentiality issues. CAs need to know a lot about consumers, receive their consumption information and interact with them. Also there must be adequate information exchanges between CA and DSOs/TSOs in order to manage issues like the purchase of flexibility products or services by DSO/TSO from CAs, the technical validation of them, the management of the energy payback effect, the sharing of topology/locational information, and the consumer and aggregator response monitoring. DSOs/TSOs and CAs have also to ensure the consumers' data privacy.

D. *Placement of imbalance costs and payment of payback effect*

Small or medium size customers typically outsource their balancing responsibility to the retailer. But the customer could have contractual arrangements with a CA to provide flexibility services. Then, if the CA and the retailer are different actors, they will have to share the responsibility for imbalances. In the same way, the aggregator (or the aggregator's BRP) should also be responsible for potential payback effects, changing the predicted consumption/production profile. Thus, balancing responsibility should be clearly defined and consistently metered to avoid gaps or overlaps.

In order to avoid possible conflicts among actors (retailer, BRP and CA), the merging of these (in particular the merging of the CA's and retailer's roles) is recommended in Address and iPower projects, since it benefits the customers and the market management. A single combined player retailer-aggregator would forecast loads and flexibility avoiding duplicities between both. He could participate in any of the existing markets, and by making use of their flexibility and allocating their consumption when prices are low, could provide his consumers with lower electricity prices. The retailer-aggregator could adapt energy price offers according to the behavior of consumers during the day, and gather their flexibility to offer to the market actual solutions to decrease/increase the whole energy consumption. The retailer-aggregator could be also a BRP himself or could pass this responsibility to another party.

E. *Other issues*

DSO/TSO's regulation (way of remuneration) has to include the fixed costs associated to the services provided to enable active demand and has to allow DSO/TSO to purchase flexibility products in order to maximize the existing network usage factor integrating RES in a sustainable way.

Consumers have the right to consume the power they have contracted, but the retail-aggregator could take advantage of this right to increase the demand, causing possible congestions and then selling load reduction to solve them. While the generation is currently not paid for reducing its production, demand might be compensated for a rescheduling.

Transparency in the selection of flexibility products or services is also a must for DSOs/TSOs.

IV. NEW PROPOSAL FOR TECHNICAL CONSTRAINTS AND FLEXIBILITY MANAGEMENT

In this work, only short term markets are considered as in Address[2]. This suits also the Spanish market. Consumers and DER flexibility will be used in order to solve the distribution grid constraints (line/transformer overloads or voltage limit violations) in the day-ahead framework.

Several assumptions are needed:

– The CA assumes the role of retailer, flexibility provider and BRP. It is also responsible for the imbalance between the scheduled energy and the real produced/consumed.
– The flexibility agreements between the aggregators and their customers are firm. No need of flexibility forecasts.
– Only the role of DSO as TA is considered for the sake of simplicity. Including the TSO would require to define the coordination between them.
– Perfect market conditions and fair play by all the agents.

Constrains are solved after the clearing of the energy market, with flexibility products (SRPs) bid by the CAs.

The general scheme of the operations, actors and time sequence proposed for the day-ahead market process is shown in Fig. 1. This scheme could be extensible to the intraday markets and real time operation with minor changes.

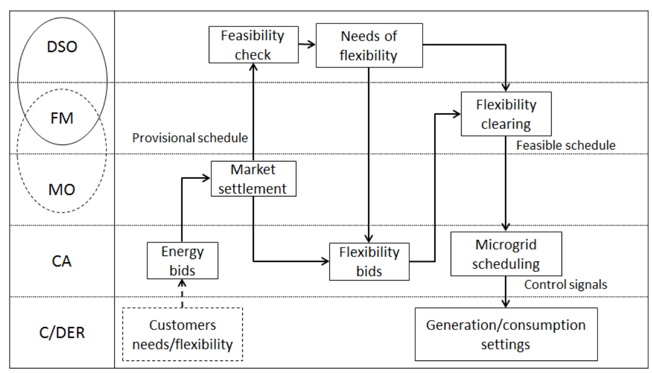

Figure 1. Scheme of the operations, actors and time sequence.

In Fig. 1, FM stands for Flexibility Market. It is a separate market where the flexibility requests and bids are solved. It can be a separate entity or run by other agent, such as the DSO or the Market Operator (MO). C/DER stands for Consumer, Distributed Energy Resource (generation facilities). The following process is proposed:

- *Customer needs/flexibility*: This is the agreement between CA and its customers (consumers/DERs) about their needs and possible flexibility. This arrangement is made long before the daily market.
- *Energy bids*: Based on needs and forecasts (prices, weather), the CA prepares and submits a bid for the whole of its customers to the Market Operator for the daily market. Flexibility bids can be included at this stage or in a later stage (Flexibility Market).

[2] In the context of the iPower project, the short term markets agree with the activation markets, where the long term flexibility products are re-traded and a better agreement can be found.

- *Market settlement*: From the different supply and demand bids, the MO sets the marginal price for energy and production/consumption bids that have been accepted. This provisional schedule is communicated to the DSO and the market agents, such as the CA. The congestions in the grid have not been taken into account at this stage.
- *Feasibility check*: The DSO checks whether the provisional schedule complies with the grid constraints.
- *Request for flexibility bids*: If there are congestions, a request of flexibility (SRPs) is made and communicated to the agents and the FM manager (or SO).
- *Flexibility bids*: Based on the flexibility request from the DSO, flexibility bids are prepared by the CA and submitted to the FM
- *Flexibility clearing*: With the bids submitted, the FM manager corrects the provisional schedule and prepares the feasible schedule, which is communicated to the market agents, among them, the CA.
- *Microgrid scheduling*: The CA sends the feasible schedule results to its customers, who fit their settings to this feasible schedule.

A further simplification could be that the CA submits the energy and flexibility bids at the same time. The rest of the operational sequence would be the same and the FM would solve the constraints using the flexibility bids of the CA, sent together with the energy bids. In order to simplify the simulations in the study case, this last option has been considered in the next section.

V. Study Case

The study case of this work is based on the European MV distribution benchmark [10], reproduced in Fig. 2.

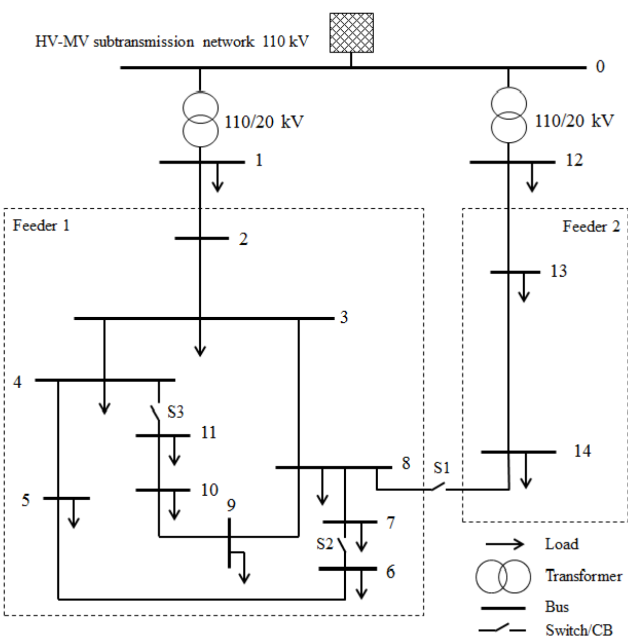

Figure 2. Topology of the MV distribution network.

Different generation units are added at various nodes, as listed in table I. All of them are considered to be at their maximum capacity except the CHP diesel generation unit connected to node 9, which provides 200 kW but can change its production in the range $0 \leq P \leq 1000$ kW. This unit is used to provide DER flexibility.

TABLE I. Parameters of DER units.

Node	DER type	$P_{committed}$ [kW]	P_{max} [kW]
3	Photovoltaic	20	20
4	Photovoltaic	20	20
5	Photovoltaic	30	30
5	Residential fuel cell	33	33
6	Photovoltaic	30	30
7	Wind turbine	1500	1500
8	Photovoltaic	30	30
9	CHP diesel[a]	200	1000
9	Photovoltaic	30	30
9	CHP fuel cell	212	212
10	Photovoltaic	40	40
10	Residential fuel cell	14	14
11	Photovoltaic	10	10

a. This generation unit offers flexibility.

Line and transformer parameters have been taken from [10], so as load parameters[3] listed in table II. The load connected at node 14 is considered as a flexible load. Flexible loads in MATPOWER, used as simulation tool, maintain a constant power factor [11].

TABLE II. Load parameters

Node	P_{load} [kW]	Q_{load} [kvar]	Type[a]
1	19,839	4,637	R, C/I
2	-	-	
3	502	209	R, C/I
4	432	108	R
5	728	182	R
6	548	137	R
7	77	47	C/I
8	587	147	R
9	574	356	C/I
10	543	161	R, C/I
11	330	83	R
12	20,010	4,693	R, C/I
13	34	21	C/I
14	540	258	R, C/I

a. R: Residential; C/I: Commercial/Industrial.

Maximum and minimum voltage limits are set to 1.05 and 0.95 p.u. at all the nodes. The transmission capacity of all the lines is 5 MVA. A power flow is run with the committed generation and load, and no limit violations appear in this case. An hourly marginal price of 35 €/MWh is considered for the operating time *t*, according to the level of Spanish electricity prices in the daily market[4]. Artificial constraints have been applied and generation offers and consumption bids for selling and purchasing energy in the day-ahead market are used to solved these constrains. A standard AC-OPF is run with MATPOWER to find the optimal dispatching from distributed generation and power from the HV network, i.e., the least-cost dispatch solution.

[3] Load values given for nodes 1 and 12 are much larger than those given for the other nodes, because these loads represent additional feeders served by the transformers. It is assumed that all the loads are balanced.

[4] Spanish average price in 2014 was 41.97 €/MWh, and the average price in January of that year was 33.62 €/MWh [12].

The constraints applied, the actions taken to solve them and the cost function are depicted in table III. Case A is the base case, without any congestion. In case B and C, transmission capacity of one line in Feeder 2 and another in Feeder 1 are limited; the first one is solved with demand flexibility (load at node 14) and the second one is solved with generation flexibility (CHP diesel unit at node 9). Case D and E derive from case C, adding additional constrains which cause an increase in the production of the CHP diesel unit.

TABLE III. CONSTRAINS, FLEXIBILITY SOLUTION AND COST FUNCTION.

	Restriction	Solution	Cost function, f [€/h]
A	None (base case)	-	1498.38
B	$S_{max,13-14}$ = 0.4 MVA $S_{max,8-9}$ = 0.7 MVA	$\Delta P_{l,14}$ = - 0.210 MW $\Delta P_{g,9}$ = + 0.240 MW	1517.28 (+18.90)
C	$S_{max,13-14}$ = 0.4 MVA $S_{max,2-3}$ = 2 MVA	$\Delta P_{l,14}$ = - 0.210 MW $\Delta P_{g\ 9}$ = + 0.250 MW	1517.39 (+19.01)
D	$S_{max,13-14}$ = 0.4 MVA $S_{max,2-3}$ = 2 MVA $P_{max,\ WT}$ = 1200 kW	$\Delta P_{l,14}$ = - 0.210 MW $\Delta P_{g,9}$ = + 0.540 MW	1541.22 (+42.84)
E	$S_{max,13-14}$ = 0.4 MVA $S_{max,2-3}$ = 2 MVA $0.99 \leq u_0 \leq 1.01$	$\Delta P_{l,14}$ = - 0.210 MW $\Delta P_{g,9}$ = + 0.370 MW	1523.29 (+24.91)

As flexible devices are placed at different feeders, they cannot compete to solve congestions in the grid. Thus a new study has been performed changing the load at node 5 to a flexible load. Now, the congestion at line 2-3 can be solved either by increasing generation at node 9 (case F) or by decreasing load at node 5 (case G), or even with a combination of both actions (case H), depending on the offers and bids of generation and demand, respectively, as shown in table IV. If both flexible devices have signed contracts with the same aggregator, it could manage their flexibility in a profitable way; otherwise the aggregators would compete in the flexibility market.

TABLE IV. GENERATION OFFERS AND LOAD BIDS FOR SOLVING CONGESTIONS.

	Generator Offers	Load bids	Action to solve the congestion
F	0.1 MW, 20 €/MWh 0.1 MW, 30 €/MWh 0.1 MW, 50 €/MWh 0.7 MW, 80 €/MWh	0.1 MW, 180 €/MWh 0.4 MW, 150 €/MWh 0.728 MW, 100 €/MWh	ΔP_g = + 0.250 MW
G	0.1 MW, 20 €/MWh 0.1 MW, 30 €/MWh 0.1 MW, 50 €/MWh 0.7 MW, 80 €/MWh	0.1 MW, 80 €/MWh 0.4 MW, 50 €/MWh 0.728 MW, 40 €/MWh	ΔP_l = - 0.23 MW
H	0.1 MW, 20 €/MWh 0.1 MW, 30 €/MWh 0.1 MW, 50 €/MWh 0.7 MW, 80 €/MWh	0.1 MW, 180 €/MWh 0.4 MW, 90 €/MWh 0.728 MW, 79 €/MWh	ΔP_g = + 0.10 MW ΔP_l = - 0.13 MW

In case F, the price of increasing generation is lower than the price of reducing consumption and the generator offers (3rd and 4th blocks) are accepted. In case G, the price of modifying the load is lower than the one of modifying the production and the 3rd block of the load bid is selected. In case H, the 3rd block of generator offers is accepted first (cheapest offer), but this action is not enough to solve the congestion and the last block of the load bid is selected then, due to its lower price.

Regarding the cost of solving the congestion, if reduction of demand would have no compensation, the most profitable solution for the DSO would be always the load reduction. But this means enters in conflict with the quality of service including continuity of supply and there would be no incentive for the DSOs to invest in grid reinforcement.

VI. CONCLUSIONS

Regulation is now of highest importance in the development and implementation of the Smart Grid. Many stakeholders are working now to define the new regulatory frame of the future.

One of the pending issues is the solution of grid constraints. An efficient and transparent method could lead to a better use of the existing grids and to reduced investments in new grid assets. This paper proposes a flexibility market that would make use of the customers' flexibility and compatible with current wholesale markets procedures.

Its implementation would however require the solution of some problems, like the needed transparency of the process, use of market power, adequate payments of flexibility and the clear definition of the roles of aggregators and DSOs. These are areas of future research currently carried out within the EU project IDE4L.

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