DEMAND SIDE INTEGRATION ASPECTS IN ACTIVE DISTRIBUTION PLANNING

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ABSTRACT

This paper presents an overview of the activities of CIGRE Working Group WG C6.19 (WG), focusing on the planning and optimization of active distribution systems. A key challenge in planning Active Distribution Systems (ADSs) is the uncertainty of the future, i.e., what level of active management will be implemented in practice? How will regulatory frameworks and connection agreements evolve to support ADSs? The present work provides some information about the closer and closer integration between network planning and Demand Side Integration that is foreseen in the future and shows the necessity to develop new tool for ADS planning.

INTRODUCTION

From the operation standpoint, real-time monitoring and control capabilities provided by the smart grid might lead to new active operation of distribution feeders such as Volt/VAR operation or new network topologies performance optimization. Better data provides opportunities for improved network performance analysis. Moreover, new market structures might influence operation and control of the distribution network and lead to new customer behaviors regarding both power consumption and local power production. Another key challenge is to understand the impact on the planning of ADSs, which results from the Demand Side Integration (DSI) strategies. There is the necessity to include the use of storage and DSI programs as a possible resource for network optimization at the planning stage to make better use of the network capacity and gain better reliability. This needs to be undertaken in the context of the uncertainties that result from the integration of high levels of intermittent generation from Renewable Energy Sources (RES), and optimized use of any stored energy. In fact, if used for peak shaving or load leveling to compensate the sudden power variations caused by RES generators, DSI programs and Distribution Energy Devices (DES) might reduce the variance of the RES production and become a viable alternative to network reinforcement (i.e., *no-network* solutions in planning).
For these reasons it is necessary to develop new planning tools that allow planners and regulators to make informed and appropriate decisions. Traditional deterministic planning approaches are becoming inadequate [1]. The work of WG C6.19 aims to illustrate the necessity and benefit of the inclusion of DSI within distribution planning [2].

DEMAND SIDE INTEGRATION

Distribution planning methodologies in a smart grid world have to face how different Demand Side Integration (DSI), Energy Efficiency (EE), and Time-Of-Use (TOU) rate scenarios will affect system peaks and how different Distributed Generation (DG), Distributed Storage (DS), Plug-in Electric Vehicle (PEV) and heat pump/electric boilers penetration scenarios will impact on system demand. Uncertainties on data concerning PEV penetration, battery charging typologies and drivers' habits make it difficult to foresee and to estimate PEV impact on electric distribution networks. It may be also considered that PEV load may be concentrated in specific areas rather than being equally geographically spread. To the same extent it is also unsure how many heat pumps and electric boilers will be deployed in the future smart grid. Further the inclusion of DSI programs for instance in relation to market perspectives are extremely correlated to regulatory frameworks that impact planners and stakeholders [3][4].
The objective functions and constraints for ADS planning are discussed in this paper. The objective functions consist of two factors. Firstly maximizing RES energy and secondly meeting demand requirements. Constraints functions consist of many factors such as:
Balancing within each time segment between generation sources (main grid, DG, PEV, DS) and load requirements,
1) Storage duration within each planning period between discharge and charge cycles,
2) Storage energy and power limits within each planning period between discharge and charge cycles,
3) DG energy and power limits within each planning period.

4)Network constraints, such as load limits between supply areas, load limits of each line and node, and voltage quality parameters.

Therefore, a probabilistic planning approach becomes necessary to tackle these aspects that are able to significantly impact on the foreseen demand and local power production. The approach should take market and control issues as well as capacity limits into account [5].

Load modelling and local power generation

Load behavior and any local power generation are some of the most important aspects in distribution planning. Indeed the entire electrical system is designed and realized to feed each user and sized to meet the energy demand.

But more than any other network element the load and local power generation are highly dependent on the time. So the estimation and forecasting should be done as accurately as possible. Indeed over-estimation can result in excess investment and cause equipment over-sizing. Instead under-estimation results in late upgrades and, consequently, degradation of the quality of service.

The knowledge of the load and local power generation profile is essential in two planning aspects:

- **the identification of the maximum stress conditions** – economically, any system reinforcement should be planned on the basis that further reinforcement will not be required for a given number of years;
- **the determination of energy losses** – the peak of lost power affects the sizing of the network's equipment, while the whole lost energy per year increases the Distribution Network Operator (DNO) operating costs.

It is therefore necessary to have an accurate load and local power generation model, since historically only very simple load representation has always been used for planning issues.

Regarding load modeling, this has typically involved commencing with to obtain typical data of different categories and types of users were defined starting from various measurement campaigns. The aim was to identify different load classes.

Many studies have been aimed at the assessment of the so-called coincidence factor. By means of this parameter the average power absorbed related to the installed power was estimated.

So traditionally it was possible to identify the loads only through the worst case condition: maximum demand (coincidence factors considered).

With the increase of distributed generation, the coincidence factor has gradually lost its reliability and meaning. In fact at the level of secondary substation not only are the loads present but also generators are present. In particular they are renewable generators which have very unpredictable and variable production. Therefore the power profile variability related to time is actually increased.

The traditional approach is still used today. It is not enough to model the loads only by the worst case performance or condition. In the traditional approach two extreme conditions are considered: Maximum Load (or no generation) and Minimum Load (or maximum generation). This approach, however, does not take into account that extreme conditions rarely occur. Sizing network based on rare cases could lead to oversized investment or conversely to have under-rated components.

The innovative proposed approach is to model the load and local power generation as much as possible through a time domain representation. It is not enough to model the loads by only one or two power values. It is necessary to have a model that takes into account the consumption and DG power profile (daily, weekly, monthly or yearly). In this way the representations of the load and generation are more reliable and closer to the actual variability. One of the major difficulties related to loads is the availability of consistent data. In order to represent a typical load profile it is not enough to know the consumption curve for a day and for one type of load. It is necessary to have several load curves related to different season, day, kind of user, etc.. The same is also true for the DG production, which might also have a seasonal and daily behavior. As well the DG power generation may have a requirement for regular outages to cope with maintenance requirements of the machinery.

Many studies were aimed to characterize profiles for different kinds of loads: residential, commercial, tertiary, industrial and agricultural loads. These curves reproduce the consumption profile for different time windows (day, week, month, season, year) or for different kind of day (holiday or working day).

Demand side integration challenges

Several possibilities can be envisaged for load contribution in system management and control as pointed out by a series of international initiatives [1], [2], [3], [4]. The following list is quite exhaustive.

Cost Reduction. A key driver for demand side integration is cost avoidance and reduction. This is particularly significant during peak demand periods featuring price spikes: during such periods, even a limited demand reduction can determine a major price reduction. For instance, load reduction can be highly valuable during peak price periods, where a limited reduction in load consumption (5%) may produce notable price reduction (up to 50%) [6]. Demand response can also save all customers' money indirectly by reducing wholesale market prices and mitigating price volatility.

Market Efficiency. When customers receive price signals and incentives, usage becomes more aligned with costs. To the extent customers alter behaviour and reduce or shift on-peak usage and costs to off-peak periods, the result is a more efficient use of the electric system.

Customer Service. Many customers welcome opportunities to manage loads as a way to save on energy bills and for other reasons such as improving the environment.

Market Power Mitigation. DR (Demand Response) programs help to mitigate market power (i.e. the abuse of a dominant market position) of traditional and new energy suppliers. This is especially the case when DR can occur essentially coincident (i.e., in near real time) with tight supplies and/or transmission constraints that might lead to market power.

Risk Management. Energy retailers purchase power in wholesale markets where prices can vary dramatically from day to day, and hour to hour. They can use demand response to substantially reduce their risk and their customers' risk in the market.

Environmental. *Demand Response* (DR) can help reduce environmental burdens placed on the air, land and water by reducing the need to operate polluting plants. DR can also reduce or defer new plant development, and transmission and distribution capacity enhancements resulting in land use benefits for neighbourhoods and country-sides.

System Security and Reliability. Customer demand management can enhance security and reliability of the electric system by providing reductions in use during emergency conditions or preventing system degradation into them. When security aspects are of major concern, the concepts and use of Interruptible Loads and of Curtailable Loads are becoming widely adopted.

Interruptible Loads (IL). ILs have been used by utilities for decades, essentially with the goal of enhancing reliability. In exchange for the possibility of being shed in case of necessity by the system operator, ILs pay their energy at a lower price.

ILs are usually large industrial customers whose main production cost is the electric power needed for the production process and who could interrupt operations for a few hours or a shift: such customer obviously look for savings on the power bill, and thus, in order to pay energy at a lower price, they are willing to accept the chance of being interrupted.

Curtailable Loads (CL). CLs imply a "milder" approach than ILs: the requirements for the participants are in fact less strict than for IL programs. Characteristics of CL usually are:

a) Smaller load reductions expected such as 100 to 200 kW minimum, but as high as 500 kW or 1,000 kW to qualify;

b) Fewer number of curtailment requests such as 15 times in the year;

c) Curtailment requests only during certain days and times, such as weekdays and between 11 a.m. and 7 p.m.;

d) Mandatory participation once an agreement has been reached;

e) Small penalties for failures to meet load reduction targets;

f) Credits based on amount of load reduced and applied against standard tariffs.

Active user. An active user is the so-called *prosumer* as a user intended to be able to have a bidirectional exchange with the DNO. The prosumer can sell its flexibility to the energy market in order to provide services and support to the distribution network. This market dynamics is called Active Demand. A user modifies its own consumption /production profile in order to reply to a price signal.

For network planning issues it is necessary to also take into account also the active demand. The load model has to consider this further variability. Today network planning cannot be designed without network management solutions. Network planning and network management are more and more integrated together. To improve the performance of the load and local power generation model two elements have to be considered:

1) level of participation of the prosumer: one of the most difficult aspects related to active demand is the forecast of the real participation of a user. The acceptance model is necessary because every user is willing to modify the consumption profile in different ways. This depends on price signal, but also on available flexibility, willingness to reduce the comfort, etc..

2) payback effect: this is the reaction of the user when the active demand request finishes. In particular these aspects can play a fundamental role in direct control of thermostatic loads, where the DSO can play with the switching on/off of some particular loads to manage for instance RES integration.

Electric vehicles integration

The large scale adoption of an electric vehicle (EV) paradigm raises the interest of many stakeholders. Currently, automotive industry is focused on EV manufacture while governments and policy makers underline the potential of environmental benefits and job opportunities creation. In the meantime, the electricity sector is evaluating future impacts on their infrastructures to serve an additional electrical load, in this case with special characteristics compared to the common ones.

EV charging schemes

Four different EV charging schemes are considered [1],[7-9]:

1. *Uncontrolled Charging at peak hours*: Electric vehicles of the same type are considered to charge at the same time, during peak hours.
2. *Multiple tariff policy aiming charging at Valley Hours*: Electric vehicles of the same type are considered to charge at the same time, during off-peak hours. This type of recharging is used to simulate the target of a multiple tariff policy. It could be obtained with new appropriate Multi-Tariff incentive schemes, and with technological solutions such as smart meters and timers in the cars.
3. *Smart Charging*: Electric vehicles are charged selecting the starting charging hour to "fill the valley" of the overall aggregated profile, considering demand and distributed generation. Local issues were not taken into account to design this type of charging, so it only fills the

valley from an aggregated point of view. This recharging system is expected to require controls system and communication systems.

4. *Smart Charging/discharging using V2G (vehicle to grid):* The electric vehicles acts, depending on the actual load and power generation condition in the network, as *controllable* load or as a generator and thereby as an energy storage (V2G) in the power systems with high penetration of renewable energy sources, depending on the actual load and power generation condition in the network. In this way the electric vehicles are used to minimize peak-consumption and to "fill the valley" [11].

Network analysis considering mass EV deployment

A massive deployment of electric vehicles will require significant changes in power system operation procedures and practices. Considering a future scenario with large scale EV integration in electrical distribution systems, it is necessary to assess the impact that results from the connection of these units with LV networks. Some of the main effects associated to high EV penetration in LV grids can be: increase of power losses, overload of lines and cables, poor voltage profiles and voltage and load imbalances [12].

The magnitude of the EV impacts on distribution networks is influenced by several factors, such as the EV integration level, the EV owners' behaviour, mobility patterns, the networks load profiles and technical characteristics, the number and location of fast charging stations in the grid, and the EV charging modes, among others.

It is important to investigate some of the key power quality issues that may arise as a result of large-scale grid integration of electric vehicles.

Distribution network planning considering EV diffusion

Distribution network investments are not expected to be very significant in year 2020, as the forecast number of EV for that year is low. However, in year 2030 the required reinforcements may be quite high, especially if there are no optimal strategies to charge EV, and then EVs are charged at peak hours. Therefore, actions should focus on the reinforcements required for year 2030, and regulations should discourage uncontrolled charging at peak hours.

In the urban areas more reinforcements are expected in MV/LV transformers than in feeders, due to capacity issues, the main relevant constraint being the current limits. In some urban areas, where voltage levels are normally at the upper limits, voltage constraints may be experienced as a result of the presence of DG. In the rural areas more reinforcements are required in feeders, in order to ensure the voltage limits. Therefore, in general, capacity issues are expected in urban areas, while voltage issues are expected in rural areas.

It should be noted that the PEV is regarded as a kind of distributed generation with stochastic output power. The distribution network planning of electric vehicles is already the subject of several research works, even though they are at a very early stage in their trial deployment in power networks and hence there remain many unanswered questions regarding their characteristics [10].

CONCLUSION

The present work provided some information about the current activities carried out within the CIGRE working group WG C6.19 that aims at illustrating the necessity and benefit of the inclusion of DSI within distribution planning. In particular the necessity to integrate network planning and Demand Side Integration represents a key issue for planners. Therefore there is the necessity to have new tools that can help planners in presence of RES and EVs in their networks.

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