E-CAR AND ECONOMIC IMPACT: ENHANCING THE SMART GRIDS

Rosa MORA
SIEMENS, S.A. – Spain
maria.rosa.mora@siemens.com

Jose OYARZABAL
Tecnalia R&I – Spain
jose.oyarzabal@tecnalia.com

Miguel CRUZ-ZAMBRANO
IREC – Spain
mcruz@irec.cat

Ana GONZALEZ
Iberdrola – Spain
ana.gb@iberdrola.es

José CORERA
Iberdrola – Spain
j.corera@iberdrola.es

ABSTRACT

The future penetration of the electrical vehicle and the related increase of electrical energy demand may impose new requirements on the power system and affect network operation, mainly, if it becomes an uncontrollable load.
The integration of e-car energy suppliers with power system actors is not an option but an absolute need to enable a secure and reliable power system.

INTRODUCTION

Thanks to the Spanish R&D VERDE project leaded by SEAT, Energy Sector is studying the impact of the e-car introduction in the current electrical networks.
In this paper, we will present some results of the studies under PT6.2 and PT6.4 during this year: how electrical grid will behave due to different e-car penetrations, how to manage the current operation, and how a Power Marketer could interface with a DSO in order to optimize the load management and consumption profiles. This work is aligned with current state of the art research regarding electric vehicle integration into the distribution grid [1]-[2]. First of all, we will describe the real network used as study case, and the different loads that are be considered in this network (base load and e-car load). After this, we will describe the current network operation, and propose a new procedure to integrate the Operation and Management of e-car, due to the aggregation of this demand and a Power Marketer / Commercial Agent that will support it. To describe the procedure, there are several use cases defined, where the optimization of the grid is done according to the different Distribution Network topology, supply points and contracts.

REFERENCE NETWORK

The electricity network considered for the simulation is composed by the MV voltage level of a large substation and its 13.2 kV distribution feeders. It supports more than 30.000 clients and it is connected to both, the transmission network and to the province primary distribution network in a recent developed area.
The MV network is a pure radial network with some circuits supplying industrial loads.
In order to mix pluggable electrical vehicle (PEV) load and conventional demand into the network model, MV/LV secondary substations have been classified into residential, commercial, industrial and others. Then, for each type of transformer substation, demand profiles for conventional load and PEV load have been built taking into account electricity demand growth and electrical vehicle usage patterns.

Table I: TC types at the Reference Network.

Type	Share [%]	Peak [kW]	Share [%]	Instal. [kW]
Residential	77,8%	39.605	79,5%	83.048
Commercial	7,4%	3.777	5,0%	5.177
Industrial	9,7%	4.920	9,2%	9.651
Others	5,1%	2.604	6,3%	6.562

The comparison of installed capacity of MV/LV transformers and measured peak load shows spare capacity: future demand growths may be accommodated without new network developments and, therefore, the network configuration could be used for short and medium term scenarios.

LOAD MODEL I: BASE LOAD.

The current customers' electrical demand supplied by the reference network is considered as conventional demand. Their segmentation (a hundred types in a DSO), is simplified to four general types: residential, commercial, industrial and others. The load demand profile of residential, commercial and industrial customers is based on real profiles for the same segmentation and province. The last type profile, others, is built from the whole province consumption data.
The base load is assumed to maintain the same profiles within the studied period without relevant changes or modifications (see Figure 1). The source base load is calculated from the normalized load profiles, type of transformer substation, installed power, owner, saturation and number of customers.

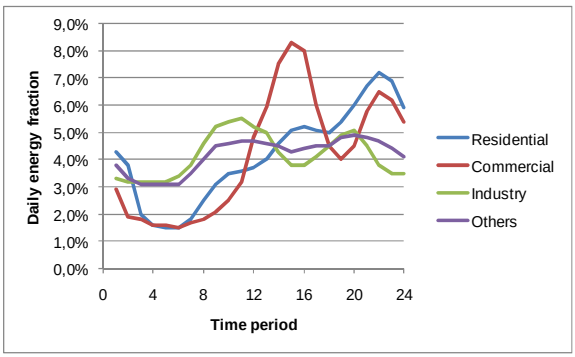

Figure 1: Demand profiles

Finally, the conventional demand growths are estimated using growth rates from UNESA projections up to 2030 [3].

LOAD MODEL II: ELECTRIC VEHICLE.

For each set of simulations, the PEV fleet is defined as a fixed number of vehicles. The PEV demand model first step consists on the estimation of the number of trips by car or motorcycle in the simulation area: 41.153. MOVILIA Project [4] data is used, considering the estimation of the supplied customers in the region [5]. A modal distribution is applied to estimate the number of PEVs in VERDE project 2020 penetration scenario, and 46 'user profiles' with different driving patterns coming from trip motivation-time matrix from MOVILIA. All vehicles of each PEV type are dispatched identically, so that 46 different 'PEV types' corresponding to the user profiles are modelled. Depending on the trip motivation, different distances are fixed. Modal dependant energy consumption figures (0.173 kWh/km for cars and 0.84 kWh/km for motorcycles) are also considered. In order to overcome the limitations of using a single-day planning horizon, a minimum SOC constrain of 30% is imposed at 00:00 AM. Regarding vehicle technical restrictions, it is assumed that the PEV can be charged in a station if it is parked. Battery energy storage limitation is considered to be 25 kWh for BEV, 10 kWh for PHEV and 5 kWh for motorcycles. As power capacity of the on-board electronics and of the plug used in the charging station, 3.7 kW are considered as nominal power, taking into account the Spanish regulation for slow charging processes.

NETWORK OPERATION PROCESS

The traditional distribution network operation was based on passive networks with energy flowing downwards and installed capacity well above the peak demand, therefore no massive automation or measurements were needed. Nowadays, the trend is to increase automation, to integrate distributed energy resources and allow reverse power flows. Nevertheless, network developments should keep power quality standards and be cost effective [6]. The current robust procedures show the specific types of problems faced by the DSOs and TSOs: the processes are not directly applicable due to the differences between both networks (size, number of components, topology, changes over the base topology, network model parameterization, uncertainty, maintenance routines, outages, etc.) but will provide an excellent starting point to define some of the new procedures.

One of those current processes that is currently in place is the detection and solution of network constraints. The TSO starts from the foreseen network topology, adds the scheduled generation and demand profiles at each network node and runs some network simulation application to identify overloaded equipment, address those issues and ensure that network security requirements are accomplished by dispatching units or rejecting schedules if needed. We studied this procedure and applied it to the PEV integration: Power Marketer, DSO, TSO and retail energy markets.

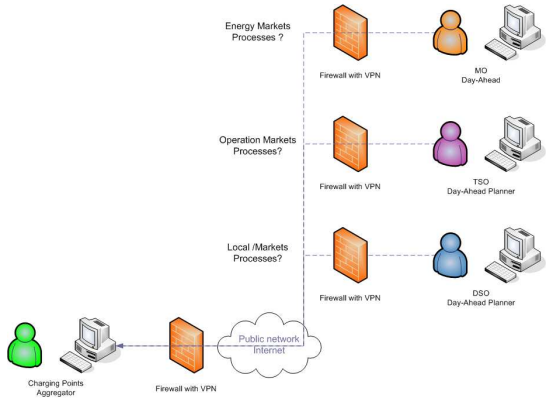

Figure 2: Charging Point Demand Aggregation & main power system actors

The general approach is inspired on the Spanish procedure for technical constraints management at the main land transmission network [7]. In contrast with the original procedure, only PEV demand is considered as controlled variable, the base load is supposed invariable and DER units' schedules are left out for simplicity.

The use case is defined by the concurrence of several Charging Point Managers (CPM) connected to a Power Marketer that are enabled to consume energy from the electrical network and manage their customer's electrical vehicle charging processes & services internally. These CPMs may contract a loose limit maximum power and a constraint of a maximum limit, depending of network requirements.
We will explain below processes, data exchange requirements, simulation tools, and architecture assessment:

Step 1: Daily schedule from Power Marketer

It defines the source electrical demand at each distribution network supply node. On day ahead basis, the Power Marketer calculates the energy and power needs of each charging point, applying forecasting methods, customer base routines, etc [1].
In a general case, several Power Marketers could operate in the same distribution network, thus there could be many CPM electrical demand schedules, each one belonging to one Power Marketer.

Step 2: Schedule validation by DSO

This step addresses the technical validation of the PEV schedules by the distribution network operator. The DSO would start from the distribution network model and apply the planned outages, to define the network topology for each time-step. The base load is defined using DSO owned forecasting tools or adding up energy suppliers' demand forecast.

1 SIEMENS's DEMS has been used as Power Marketer forecasting, operation and optimization tool.

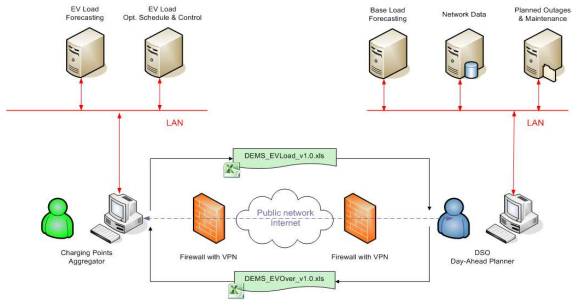

Figure 3: CPA and DSO integration architecture & processes

First, the DSO adds up the conventional demand and PEV demand for each transformer substation and identifies any possible overload, rejecting proportionally PEV load schedules. Then, for each time step, a load flow[2] is executed to identify any overloaded feeder segment, or voltages out of statutory limits. Finally, maximum acceptable PEV load at each network node is returned back to the Power Marketer for optimization.

Step 3: Approved daily schedule

This is intended to calculate a valid PEV schedule so that no network constraints appear.
The rejected PEV loading is processed by each charging point Power Marketer and then it is optimized to comply with network imposed limits and customer base contracts accordingly to the Power Marketer policy and objectives.
At last, the new schedules are submitted to the DSO to perform the final validation and approval.

NETWORK SIMULATIONS

In this section, we will show the results obtained applying the described methodology for different use cases.

Case 1: MV/LV Distribution transformer

The first use case applies the validation process to a MV/LV distribution transformer. As shown in Figure 4, the local CPM considers economical and technical signals from the electricity system, as well as the PEV users mobility needs as main inputs for decision making process. Hence, in Step 1 of the network operation process, the CPM optimizes its day-ahead planning, based on its demand forecasts, and the price signal. After schedule validation by the DSO (Step 2), distribution transformer overloads are identified at peak hours. Then, maximum acceptable loading is returned back to the CPM for optimization. In step 3, the rejected PEV loading is processed by the CPM and then it is re-optimized to comply with network imposed limits, as well as customer base contracts (see Figure 5). The new schedules are submitted to the DSO to perform the final validation and approval.

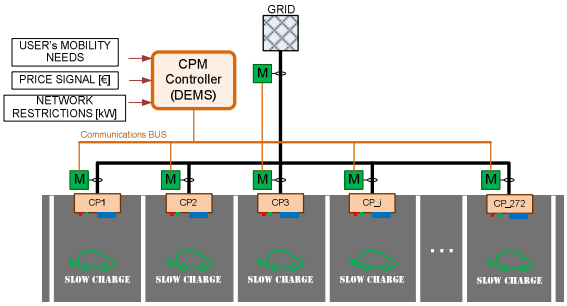

Figure 4: Local charging point manager schematics.

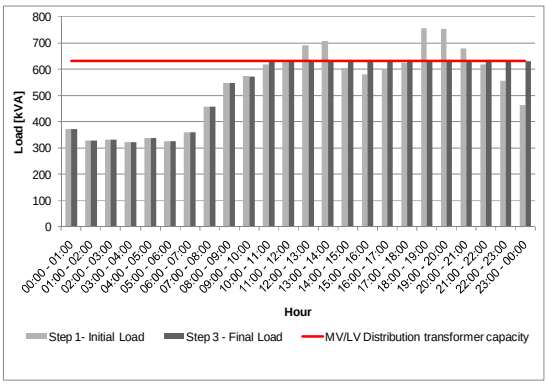

Figure 5: Load profile before and after the DSO network operation processes.

Case 2: MV Distribution feeder

The second use case extends the analysis to the distribution feeder level. In this case, the DSO has to deal with a group of Power Marketers which aggregate local CPMs, operating a certain number of charging stations along a distribution feeder (Figure 6). After receiving daily planning from every Power Marketer in Step 1, the DSO has to execute a load flow for each time-step, to point out any overloaded feeder segment or voltages out of statutory limits. Then, the DSO has to define the amount of demand to be reduced by each Power Marketer taking into account the spare capacity of the feeder (after supplying conventional load). Power Marketers in turn will decide the amount of demand to be reduced at each local CPM.
The software DEMS is applied to decide which set points are sent to each charging facility, by solving an optimization problem (Figure 7). As shown in then next figure, the initial load exceeding the feeder spare capacity is shifted to other day slots where feeder saturation is lower.

2 SIEMENS's PSS/E and Python scripting has been used as DSO validation tool.

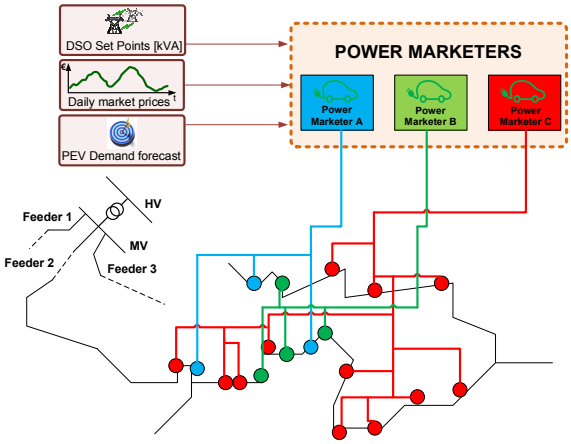

Figure 6: Local charging point manager schematics.

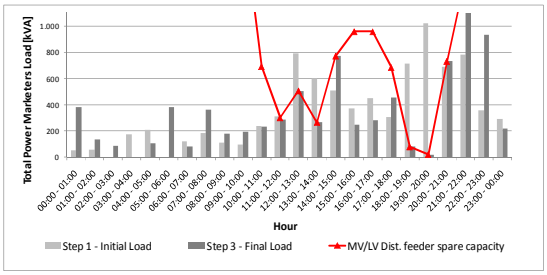

Figure 7: Load profile before and after the DSO network operation processes.

CONCLUSSIONS AND FURTHER RESEARCH

At the early stages of distributed energy resources deployment, their integration approach was based on worst case studies. As DER penetration increases, this strategy should be enhanced to provide a reliable and efficient power system operation. The expected development of the EV & PEV and the activity of the Power Marketers could lead to a new need of integration with power system operation and planning. Operation has to be considered from the very beginning in order to achieve the best possible solution. The presented work shows how, with already available tools, current distribution network operators and future PEV suppliers could cooperate together to guarantee the secure operation of the distribution network while satisfying their respective customer needs.

The opened communication channels between power marketers and electrical network operators paves the way to the appearance of new advanced services. Among them, the support for the release of overloads and assistance during service restoration are foreseen.

REFERENCES

[1] Lopes, J.A.P.; Soares, F.J.; Almeida, P.M.R.; , "Integration of Electric Vehicles in the Electric Power System," *Proceedings of the IEEE* , vol.99, no.1, pp.168-183, Jan. 2011 doi: 10.1109/JPROC.2010.2066250

[2] Gómez San Román, T., Momber I. et al, "Regulatory framework and business models for charging plug-in electric vehicles: Infrastructure, agents, and commercial relationships," *Energy Policy*, vol. 39, Issue 10, OCT 2011, Pages 6360-6375, ISSN 0301-4215, 10.1016/j.enpol.2011.07.037.

[3] UNESA, 2006, *Prospectiva de generación eléctrica 2030*, UNESA, Madrid, Spain, 4-13.

[4] Proyecto MOVILIA2006. Ministerio de Fomento. Spain, 2006.

[5] M. Cruz, A. Santandreu, et al, "Demand side management and electric vehicle integration (VERDE)".– *CIRED*, Paper 0898, Frankfurt, Germany, 2011.

[6] Oyarzabal, J.; Marti, J.; Ilo, A. et al, 2009, "Integration of DER into power system operation through Virtual Power Plant concept applied for voltage regulation", *Integration of Wide-Scale Renewable Resources Into the Power Delivery System, 2009 CIGRE/IEEE PES Joint Symposium*, 1 – 7.

[7] P.O. 3.2 Resolución de restricciones técnicas, *BOE-A-2010-16441*, Spain

[8] R. Mora, R. Ramírez, et al, "Smart grid communications emulator (100 000 synthetic users)." – *CIRED*, Paper 0850, Frankfurt, Germany, 2011.

[9] R. Mora, A. López, et al., "Early-stage smart grid deployment: leveraging dno's legacy assets. *CIRED*, paper 0122, Lyon, France, 2010.

[10] A. López, D. Román, et al., "Simulación de las Comunicaciones en SmartGrids para la Gestión de la Demanda". *CIGRE*, Madrid, Spain, 2010.

[11] E. García, A. Rodríguez, et al., "Active demand side management operator tool (SGCLOS) and new communications architecture in the XXI century electrical grid.". *CIGRE*, paper C6-203, Paris, 2010.

[12] R. Mora, A. López, et al., "Communications architecture of smart grids to manage the electrical demand", *WSPLC*, paper 4169, Udine, Italy, 2009.

[13] R. Mora, A. López et al., "Demand Management Communications Architecture", *CIRED SmartGrids*, paper 368, Praha, Czech Republic, 2009.

[14] R. Mora, A. López et al., "Smart Communications in Demand Management", *CIRED SmartGrids*, paper 15, Frankfurt, Germany, 2008.

ACKNOWLEDGMENTS

This paper is developed within the VERDE Project, led by SEAT Technical Centre and funded by the Ministry of Science and Innovation within the CENIT Programme (National Strategic Consortiums for Technical Research).