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Hosting Capacity of Solar Photovoltaics in Distribution Grids under Different Pricing Schemes

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***Abstract*—Most of the solar photovoltaic (SPV) installations are connected to distribution networks. The majority of these systems are represented by single-phase rooftop SPVs connected to residential low voltage (LV) grids. The large SPV shares lead to grid integration issues such as voltage rise, overloading of the network components, voltage phase unbalance etc. A rapid expansion of Electric Vehicles (EVs) technology is estimated, whose connection is also expected to take place in the LV networks. EVs might represent a possible solution to the SPV integration issues as they can be used as fast and distributed battery storages, and locally absorb excess PV generation. This work analyzes the use of EV charging to increase the PV hosting capacity in LV networks, considering the electricity tariffs schemes like time-of-use (TOU) , net metering and Distribution Locational Marginal Pricing (DLMP) tariffs. The results show that with the present TOU tariffs the EV integration in LV networks does not ease the grid bottlenecks for large PV penetration. Under the Net metering and DLMP the EV integration in LV grids tend to increase the PV hosting capacity.**

***Index Terms*— electric vehicles, locational marginal pricing, net metering, solar photovoltaics, time-of-use tariff**

I. Introduction

Solar photovoltaic installations have been continuously increasing in the recent years, reaching a new record of 178 GW of worldwide installed capacity at the end of 2014 [1]. SPV represents an important power source in several countries–more than 7% of the national electricity demand was provided by photovoltaic generation [1] in 2014 in Italy, Germany and Greece. Low Voltage networks in particular experienced an exponential increase in the number of installations. At the end of 2012, 96% of the total numbers of PV units were installed in the LV grid in Italy [2]. The large integration of distributed generation, such as SPV, can lead to operation challenges in distribution grids like reverse power flow in the feeder during conditions of high production and low load demand. This phenomenon can also lead to voltage rise along the network feeders and variations of the voltage magnitude over the design limits. Possible overloading of the network components, such as cables and distribution transformers [3], represents another integration issue. If single-phase PV inverters are unequally distributed among the three phases of the system, an additional integration issue is represented by voltage phase unbalance. The EV technology is nowadays in its early stages, but its proliferation is expected to increase exponentially in the next years, with a forecasted global fleet of 20 million electrical/hybrid vehicles by 2020 [4]. EVs are flexible loads, i.e. their power demand due to the battery charging is not simultaneous with their use for driving. For this reason, the EV load demand can be controlled to some extent, without modifying the driving habits and needs. Referring to [5], [6], the use of EVs as distributed storages can ease the grid bottlenecks for large PV integration, by charging their batteries to absorb part of the excess generated energy, and thus helping in increase of the PV hosting capacity. In this paper, different penetration levels of EV charging scenario to increase the PV hosting capacity in residential LV networks, under relevant electricity pricing mechanisms (TOU, net Metering, DLMP), are investigated. The PV hosting capacity is evaluated by an iterative process where the maximum allowed installed capacity that does not violate important power quality indicators like the maximum loading of all network components, voltage magnitude variations and voltage phase unbalance for any hour of the year. The CIGRÉ European LV benchmark model has been adapted into a test network model with radial topology and high SPV penetration [7]. The various sections of this paper are organized as follows. Section II presents the model of the LV network. The electricity tariffs schemes for an Italian SPV scenario are illustrated in Section III. The methodology used to perform the analysis is described in Section IV. Section V presents the simulations results and the discussion of the findings of this work and the conclusions are drawn in Section VI.

II. Case Study

A. Distribution Grid Model

In order to carry out the investigation, a test case based on the European benchmark for LV networks [7] developed by the Task Force C6.04.02 CIGRÉ is used. It represents a radial LV network, with one feeder modeled in detail and the others represented as aggregate loads. In order to adapt the original model to an Italian case study, a series of modifications have been conducted in the grid model. Those include the lengthening of the main feeder, the modeling of 30 household units as single-phase cable connections and the use of load and generation profiles obtained from measurements. Each household connection is modeled as the sum of two constant power loads (one representing the domestic load demand and the other a 3.5kW, 24kWh EV) and a PV generating unit. The single-line diagram of the simulation model is shown in Fig. 1.

B. *Load and Generation Profiles*

The yearly domestic load profile in [8] has been used to model the load demand of the residential units in this work. The original profile was obtained from a sample of buildings measurements from standard European load profiles [8]. The diversity in load profiles is obtained by shifting the original profile one week forward and/or backward for the different household units. Thus, the consumption profile for one Monday is replaced by another Monday, etc. An example of three domestic load profiles obtained with this process can be found in Fig. 2. A typical residential connection assumes rated power of 4.50 kW, peak demand of 3.76 kW, annual consumption of 2979 kWh and power factor of 0.95. The PV power output profile is based on the data obtained from ABB solar irradiance measurements in the city on the outskirts of Florence, Italy. A yearly measurement profile with hourly resolution is used in this work. The cloud transient effects are neglected in this work and it is assumed that all the PV units in the LV network follow the same generation profile. An example of the generation profile during one week is presented in Fig. 3. The EV load profile is obtained as a result of an optimization process explained in detail in Section IV.

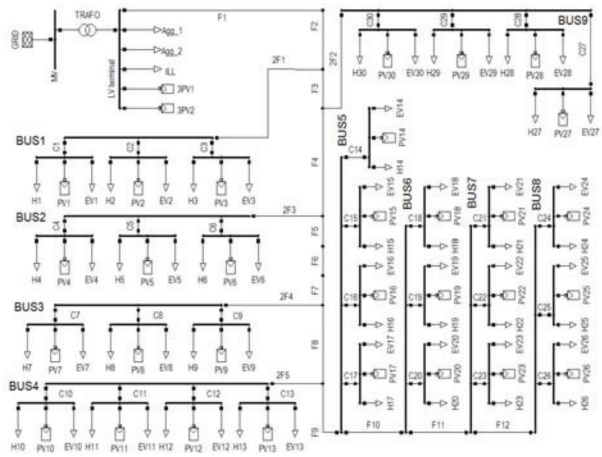

Figure 1. Single-line diagram of the LV residential network

III. Electricity Pricing Schemes

The EV charging scenarios proposed in this work to support high SPV penetration are based on present electricity tariffs structure for Italian residential customers (TOU, net metering) and a possible future DLMP structure.

A. *Time-of-Use Tariff*

Time-of-Use tariffs are used to avoid excessive peak demand in the grid, by applying a variable price according to the time of the day. A higher price is set during peak load periods and lower rates during off-peak periods, encouraging the customer to shift part of the energy demand to off-peak hours. In the Italian case study *Tariffa Bioraria* represents a TOU tariff scheme available for residential customers [9]. This tariff scheme differentiates between peak hours (F1) from off-peak ones (F2), by applying two different electricity prices. The tariff rates for F1 and F2 are 24.08c €/kWh and 23.45 c€/kWh respectively. Peak hours include the time range from 8 AM to 7 PM from Monday to Friday, and off-peak hours include the remaining hours and all the weekend. The final price of electricity is the sum of different components, dependent on the energy consumption, the rated power of the connection point and time-of-use of electricity.

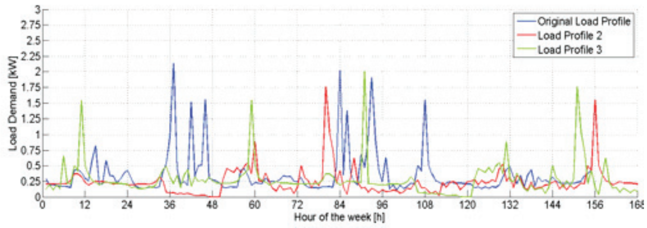

Figure 2. Example of three domestic load profiles during one week.

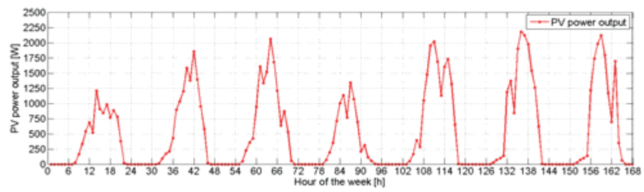

Figure 3. Example of the PV power output profile during first week of April.

B. *Net Metering Service*

Net Metering is a service available for an electric customer who also owns a generating unit, such as SPV. By using net metering service the energy produced which is not instantaneously consumed can be delivered to the local distribution network. Thereby, the consumer does not depend on the electricity provided by the Distribution System Operator (DSO) during the applicable billing period. In the Italian case study, Net Metering service is put on top of the above-mentioned TOU tariffs. In the event that the customer's generation exceeds the consumption over the billing period, such as the case analyzed in this work, the customer is paid for the energy sold to the network, at a price per kWh lower than the cost of the purchased energy. For this reason, and because the network charges are not applied to the electricity instantaneously self-consumed, net metering can potentially represent the best tariff for customers who want to connect an additional flexible load demand, such as an EV.

C. *Distribution Locational Marginal Pricing*

Locational Marginal Pricing (LMP) is a pricing structure based on real time pricing. It reflects the marginal cost of electricity supply for an additional increment of power to a node in the network [10]. Since the cost for the DSO to supply loads connected to different nodes of the system can be different, due to different line losses, LMP structure results in different prices for different nodes, hence the term *Locational.* While DLMP has already been adopted in transmission networks, this pricing structure has still to be implemented in the distribution level [10]. The target of DLMP is to obtain a higher synergy between the load demand and SPV production than in the previously described scenarios, by the implementation of a price structure where the cost of electricity is dependent on the marginal feeder losses introduced by each load and generating unit in the system. The cost calculation is based on the work of [10], and for bus k and the time t can be expressed by (1).

$$c_{t,k} = c_{t,TOU}.(1+\frac{dLoss_t}{dS_t}) \tag{1}$$

where S is the power demand at time t and $c_{t,TOU}$ is the present TOU tariff. Referring to [11], for unbalanced distribution systems the loss sensitivity $\lambda = dLoss/dS$, for a node n and phase ϕ, can be represented as:

$$\lambda_{n,\phi} = \frac{2}{|V_{n,\phi}|}.(\sum_{l}(I_{l,a}.R_{l,a\phi}.\cos(\theta_{I,l,a}-\theta_{I,n,\phi})+ \tag{2}$$
$$(I_{l,b}.R_{l,b\phi}.\cos(\theta_{I,l,b}-\theta_{I,n,\phi})+(I_{l,c}.R_{l,c\phi}.\cos(\theta_{I,l,c}-\theta_{I,n,\phi})$$

where $V_{n,\phi}$ is the voltage magnitude of phase ϕ at the node n, l is the number of lines in the radial network, $Il,_{\phi}$ is the line current in line l and phase ϕ, $R_{l,\phi}$ is the real part of the line impedance $Zl,_{\phi}$, line l, $\theta_{I,l,\phi}$ is the angle of phase current ϕ in line l and $\theta_{I,n,\phi}$ is the angle of phase current ϕ at the node n where the loss sensitivity is evaluated. The resulting electricity price calculated using (1), (2) varies in a wide range along the year. As an example, the DLMP electricity prices for BUS8 are presented in Fig. 4.

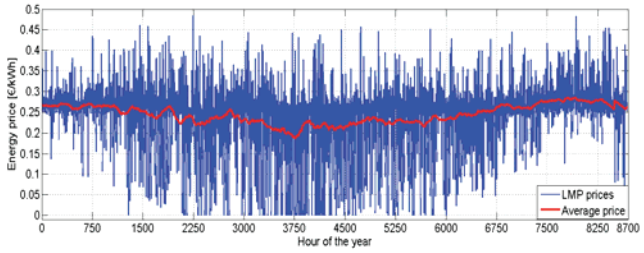

Figure 4. Yearly DLMP at BUS8, the farthest node in the test grid.

IV. METHODOLOGY

The hosting capacity is defined as the maximum PV installed capacity that can be allocated into the LV grid without the violation of any of the grid constraints assumed. A series of Power Quality (PQ) indicators has been chosen to determine the PV hosting capacity. The conservative constraints used in this work are a) Voltage magnitude variations should always be within ±5% of the rated value, b) All the network cables currents should not exceed the ampacity value, c) The distribution transformer current should not exceed the full load current and d) Voltage phase unbalance, evaluated as Percentage Voltage Unbalance Factor (%VUF) should never exceed 2%. Some of the other assumptions made in this work is that the EV owner charges his/her vehicle at the minimum cost at any time, a default value of 90% has to be restored before the EV is used again the next day and the EV owners can only charge their vehicles at home, due to the lack of fast charging infrastructures and the driver's habits.

A. *Evaluation of the PV Hosting Capacity*

An iterative process is used for the determination of the maximum PV hosting capacity. The PV generation profile is multiplied by a scaling factor, initially set to zero. Each iteration increases the scaling factor by a fixed step. Unbalanced load-flow simulations are performed at each iteration and it is checked that the PQ limits are not violated. If any of the limits are violated, the maximum hosting capacity has been reached; otherwise, the iterative process is continued. The algorithm is implemented in a DIgSILENT Programming Language (DPL). The PV hosting capacity at the present state of the network, when no EVs are connected, is found to be 83.25 kW, i.e. 2.78 kW for each of the 30 PV residential units (maximum 6kW). The main grid bottleneck for a large PV integration is the voltage magnitude at the end of the radial feeder, which reaches the +5% limit at BUS8 during the central hours of the year, as shown from the plot of Fig. 5. Since Bus 8 is the furthest node from the transformer, it has the maximum voltage sensitivity to the load and generation variation in the feeder and is used as a reference node in the remaining part of this work. The same procedure is used to determine the hosting capacity of SPVs with EVs load profiles added to the grid under the three pricing mechanisms.

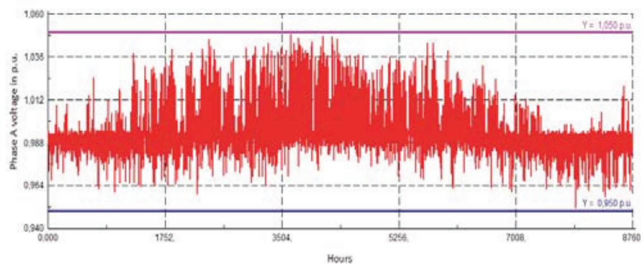

Figure.5 Yearly voltage profile of phase A at BUS8.

B. *Generation of the EV Load Profile*

. For this reason, the EV load profiles are generated as the result of an optimization process with MATLAB. The decision variable of the minimization process is the EV charger load demand. The cost function is the cost of electricity for the EV owner and constraint of the battery State-of-Charge - maximum and minimum limits, the EV charger technology and the availability for charging. A flowchart of the algorithm is available in Fig. 6. The cost function for the TOU scenario is

$$\mathrm{f(x)} = \sum_{i}^{24} c_i \, p_i \tag{3}$$

For the Net Metering and DLMP scenarios, since the cost function is the cost for supplying the entire domestic load demand, inclusive of domestic load, it can be expressed as:

$$\mathrm{f(x)} = \sum_{i}^{24} c_i . \left(p_i + p_{dom} - p_{pv} \right) \tag{4}$$

In both cases, the optimization is subject to the constraints:

$$p_i \geq 0 \tag{5}$$

$$p_i \leq p_{max} \tag{6}$$

$$\Sigma\, p_i = 0.9 - \text{SOC} \qquad (7)$$

where p_i is the EV charger load demand, p_{dom} is the domestic load power demand, p_{pv} is the PV power output, c_i is the hourly price of electricity (varies for differing pricing schemes), p_{max} is the maximum EV load demand and *SOC* is the battery state of charge at the arrival at the charging point.

To take into account the EV availability constraint, the maximum allowed power p_{max} is set to zero when the EV is not available for home-charging. The EV energy demand and the availability for charging are generated from the data of the 2012 EU mobility survey [12]. Different EV shares are introduced in the LV network, starting from the end of the feeder and proceeding towards the distribution transformer. This represents the worst case situation as the remote terminals have higher voltage sensitivity to load variation. These share are defined as a percentage of the number of households, e.g. 100% represents one EV for every household connection i.e. 30 EVs.

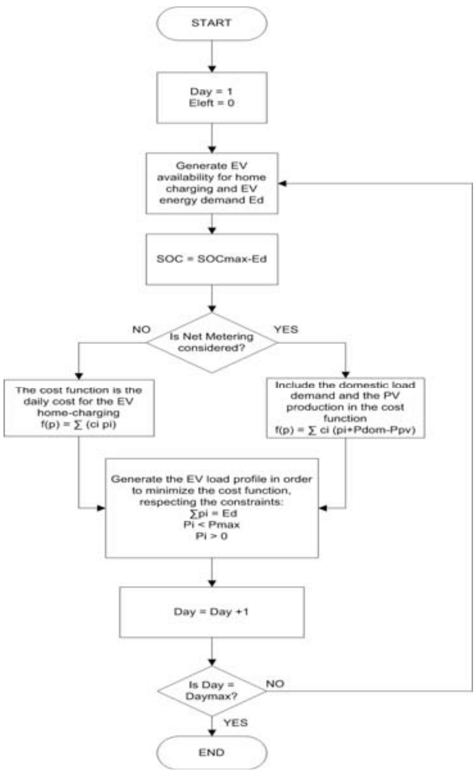

Figure 6. Flowchart of the algorithm used to generate the EV load profile.

V. Simulation Results and Discussion

A. Time-of-Use Tariff Scenario

The introduction of EVs in the context of the present TOU tariffs results in a limited increase in the feeder PV hosting capacity, as shown in Fig. 7. The present tariff sets higher prices during most of daylight hours and the EV owner is encouraged to charge the vehicle simultaneously with the domestic load demand rather than the PV peak production as seen in Fig. 8. This could result in high loading of the radial feeder and consequent under-voltages at the end of it for high EV penetration. Large integration of EVs in the LV network results into voltage magnitude variations at the end of the radial feeder as can be seen from Table I, for EV shares up to 70% the voltage magnitude at the furthest node of the feeder exceeds the -5% constraint for 2 h/y.

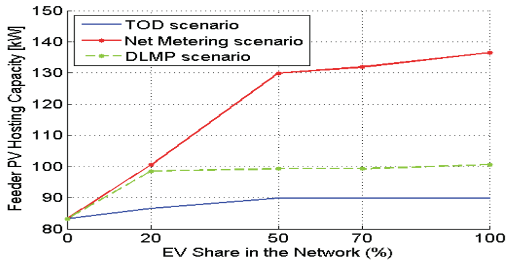

Figure 7. Increase of the feeder PV hosting capacity for varying EV shares and different pricing structures.

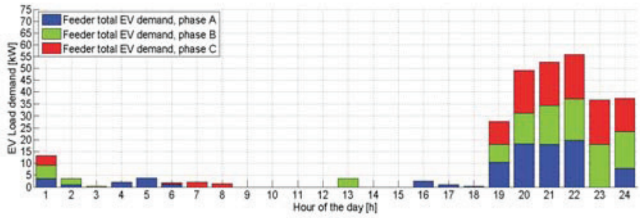

Figure 8. Charging profile of EVs for TOU scenario

B. Net Metering Scenario

The addition of net metering service, on top of the TOU scheme, results into significant increase in the feeder PV hosting capacity, with a maximum of 136.53kW with a 100% EV penetration as seen in Fig. 7. This pricing mechanism rewards the local consumption of the PV generated energy and the EV load absorbs part of the excess production and ease the bottlenecks for large PV integration. On the other hand, this scenario presents a series of EV integration issues. Like voltage phase unbalance (Table I). Unlike TOU scenario, where most of the EVs start charging simultaneously as soon as the tariff moves to the lower value, net metering structure results in a scattering of the EV load along the daytime. Because it is more likely that only few EVs are charging at the same time, statistically it is more likely that the charging is not distributed equally among the three phases and therefore the voltage phase unbalance increases. The voltage phase unbalance depends more on the phase where the EVs are charging, rather than the number of EVs simultaneously connected to the grid. In the net metering scenario, since the EV charging profile depends on a larger series of factors than in the TOU scenario, including the vehicle availability for home-charging during daytime, the PV power output and the domestic load demand, the EV load demand is spread during the 24h of the day. For this reasons it is more likely that few EVs are charging on the same phase, rather than to have uniform EV charging distribution over the 3 phases, as can be seen from the plot of Fig. 9.

C. Distribution Locational Marginal Pricing Scenario

It can be seen from the plot of Fig. 7 that the increase in the PV hosting capacity is intermediate between the values of the above two schemes. The DLMP structure overcomes the under-voltage issues compared to the previous scenarios. No voltage magnitude variations are registered at any hour of the year and in any node of the LV network as seen from Table I. This is so because the DLMP tariff penalizes the consumption during high load demand conditions with tariffs up to twice the present TOU peak hours' rate. Voltage phase unbalance issue remains unsolved, since the scattering of the EV load demand, as in net metering scenario, does not present significant differences with DLMP. The unequal distribution of the EV charging profile among the three phases can be found in Fig. 10. An advantage of the implementation of DLMP pricing structure is the reduction of the feeder line losses as it can be seen from Fig. 11.

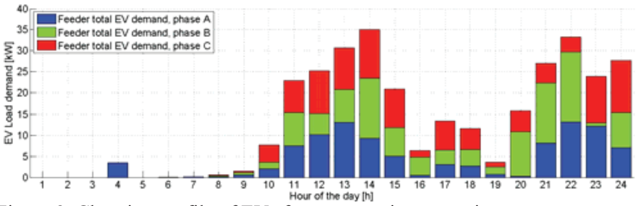

Figure 9. Charging profile of EVs for net metering scenario

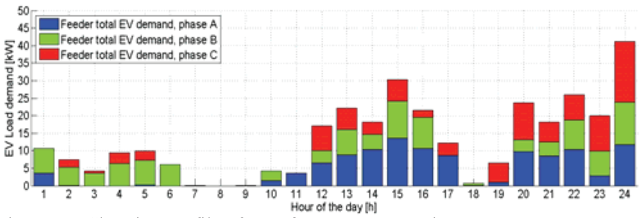

Figure 10. Charging profile of EVs for DLMP scenario

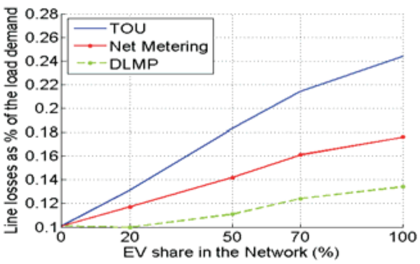

Figure 11. Feeder line losses for the three pricing scenarios.

VI. CONCLUSIONS

This paper analyses the impact of varying proportions of EVs on the PV hosting capacity in LV residential grids under different electricity pricing schemes. The impact assessment considers distribution grid bottlenecks for high levels of PV integration. It has been concluded that for the present Italian TOU electricity tariffs, the introduction of the EV loads in the network cannot increase significantly the PV penetration, owing to under voltages caused by the former. For Net Metering and DLMP, a positive correlation between the number of EVs introduced in the network and the increase of the PV capacity is very much feasible. A series of integrations issues for the EVs, however, persists. Voltage phase unbalance remains an unsolved issue. The violation of the 2% %VUF index considered has been registered for almost every EV share introduced. It has to be noticed that the number of occurrences is limited to few hours in a year, and the peak values are close to the 2% value that defines the constraint. Overall, the additional SPV hosting capacity generated by EV introduction in the grid can lead to postponements or reduction of the need for grid upgrades and reinforcements.

TABLE I. POWER QUALITY INDICATORS FOR DIFFERENT EV SHARES

Power quality indicator	EV Share (%)			
	20	*50*	*70*	*100*
Minimum bus voltage at BUS8 (limit - 0.950 p.u.)				
TOU	0.952	0.951	0.947 (2)*	0.944 (2)*
Net metering	0.952	0.952	0.949 (2)*	0.948 (3)*
DLMP	0.955	0.953	0.951	0.951
Maximum %VUF (limit 2.000)				
TOU	1.974	1.760	1.761	1.792
Net metering	2.493 (2)*	1.803	2.018 (1)*	2.852 (1)*
DLMP	2.747 (5)*	2.394 (5)*	2.398 (2)*	2.730 (9)*

*Values in brackets indicate the number of violations of the constraint, values in h/y.

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