Increasing PV hosting capacity in LV grids with a probabilistic planning approach

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***Abstract*—Enabling a high hosting capacity of PV infeed in LV grids can be a great challenge for distribution system operators. To assure 100% PV infeed at any time the maximal PV infeed with the minimal load situation is used in conventional network planning. When looking at real grid situations, this worst case scenario only occurs rarely. This paper describes a probabilistic planning approach that increases the hosting capacity of PV while an active power curtailment, realized with PV inverter's P(U) control, is accepted for short time periods. As a consequence, this probabilistic planning approach improves the assessment of the available network capacity for PV.**

Keywords—probabilistic planning; PV integration; hosting capacity; PV inverter P(U) control

I. MOTIVATION

The goals of the European commission obligate all market participants to increase energy efficiency and the share of renewable generation. Enabling a high share of PV infeed in LV grids can be a great challenge for distribution system operators (DSO). PV connection requests arise spatial and temporal spread over the whole grid area. When a planned PV system has the potential of exceeding the defined voltage limits [1][2] at the point of common coupling, the customer has to pay to establish a connection to the nearest appropriate connection point. To enable the infeed, it is necessary to limit the PV installation, or the grid has to be reinforced.

From the generation's point of view the optimum is full infeed without limitation at any time to maximize energy output and profit. From the DSO's point of view the optimum is keeping grid costs as small as possible. In many cases this results in a reduction of allowed generation infeed. To support the goals of the European commission it is necessary to find an economic optimum that is a compromise between network investment costs and decentralized produced energy.

II. CONVENTIONAL PLANNING APPROACH

In conventional grid planning the maximal generation infeed with the worst operation condition in the distribution grid is assumed for the assessment of a connection request. Therefore the maximal possible busbar voltage at the secondary substation is considered (e.g. 107% according to [1] and [2]). These considerations assure 100% infeed at any time and compliance to the 110% limits according to EN50160 [3].

When grids have reached their capacity according to this conventional assessment approach, a reduction of the requested infeed power can be offered to the customer. With this solution the available energy potential is not fully used. As an alternative, the customer could pay the connection to the nearest appropriate connection point. As a consequence, in many cases the installation is no longer economically profitable for the customer. With the growing density of distributed generation (DG) the number of refused connection requests according to conventional planning increases.

Looking at real grid situations shows that critical voltage levels occur only very seldom. Therefore a higher share of DG is possible because the conventional assessment approach does not incorporate the existing reserves of the overall system.

III. PROBABILISTIC ASSESSMENT FOR PV INSTALLATIONS

The probabilistic planning approach incorporates the statistical behavior of the MV/LV transformer's busbar voltage and the statistical behavior of the PV infeed.

The aim of the planning approach is to increase the decentralized installed PV power as well as the decentralized produced energy while accepting small active power curtailments. This goal is only achievable if the DSO is able to curtail active power infeed or switch off PV installations for seldom time periods when the voltage upper limit is reached.

Based on the assessment formula for voltage rise according [2] a probabilistic reduction factor F is introduced (1) that incorporates the probability of occurrence of the voltage rise.

$$d := \Delta S_a / S_{SC} \cdot \cos(\Psi - \varphi) \cdot F \qquad (1)$$

d … relative voltage rise
ΔS_a … infeed power [kVA]
for PV installations [kWp]
S_{SC} … Short circuit power at the connection point [kVA]

Ψ … grid angle [°]
φ … angle of power change [°]
F … probabilistic reduction factor [≤1].

The following chapters describe the calculation of this probabilistic reduction factor F.

A. *Methodology*

The most relevant parameters for the probabilistic approach are the variation of the transformer busbar voltage as well as the variation of the PV infeed power. Both parameters have their individual distribution between their highest and their lowest value. For the calculations of the variation of PV infeed the examination of noonday is sufficient.

B. *Frequency distribution of PV infeed*

When the PV infeed power is normalized to the installation's nominal power [kWp] (Fig. 1), the empirical probability from the PV power measurements $f_{PVpower}$ (Fig. 2) can be calculated with a kernel density estimation according to (2) with the Triweight kernel (3) [4].

$$f(x) := \frac{1}{nh}\sum_{i=1}^{n} K\left(\frac{x - X_i}{h}\right) \qquad (2)$$

$$K(u) := \frac{35}{32}\left(1 - u^2\right)^3 \qquad (3)$$

When the power flow calculation is linearized, the maximal voltage rise caused by all PV installations in the LV grid ΔU_{PV} shows the same frequency distribution as shown in Fig. 2 ($f_{\Delta UPV} = f_{\mathrm{PVpower}}$).

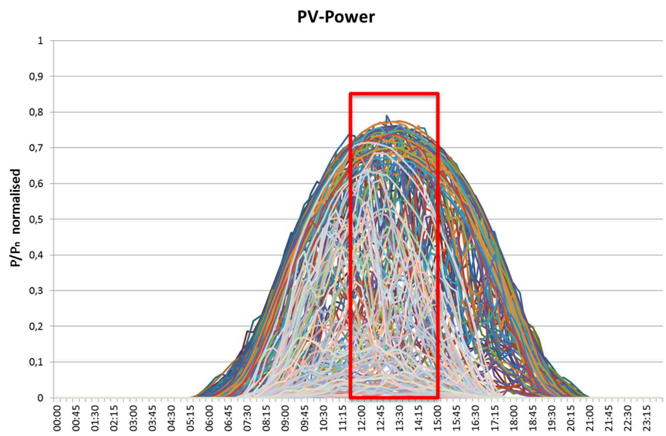

Fig. 1. Normalized mean value of PV power ($\mathrm{PV_{power}}$) from 10 PV inverters plotted for each day of a year (kW/kWp). Red rectangle denotes the timeframe (midday) that incorporates the values used for f_{PVpower} shown in Fig. 2.

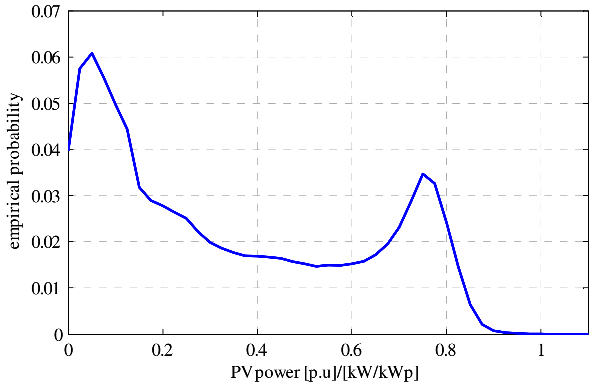

Fig. 2. Empirical probability of normalized PV infeed powers f_{PVpower} (during midday)

C. *Frequency distribution of the transformer busbar voltage*

Also the empirical probability from the measured transformer busbar voltages can be calculated with a kernel density estimation (2). In the examined example (Fig. 3) the frequency distribution corresponds to a Triweight distribution (Fig. 4).

The distribution of the voltage variation of the transformer busbar voltage U_{BB} is caused by the deadband of the on-load-tap-changer's voltage controller at the primary substation as well as by the voltage rise and drop in the MV grid.

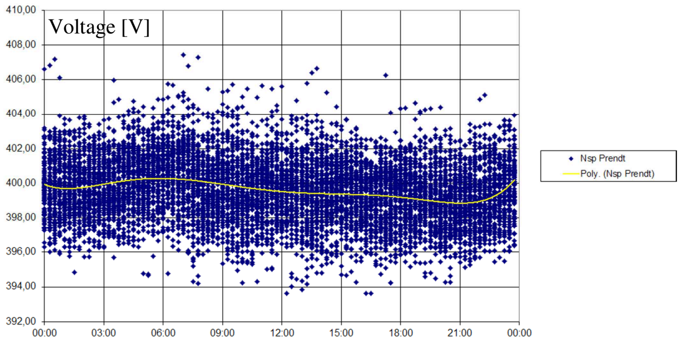

Fig. 3. Measured transformer busbar voltage U_{BB} (June – September) in "Prendt" (LV grid in Upper Austria) sorted / grouped by daytime

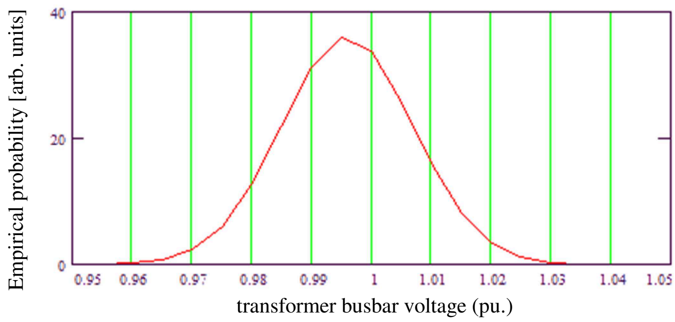

Fig. 4. Empirical probability of normalized transformer busbar voltage $f_{\Delta UBB}$

D. *Determination of the voltage rise and it's frequency distribution*

Within the following calculations it is assumed that the values of the transformer busbar voltage U_{BB} are uncorrelated to the PV infeed PV_{power} (statistically independent).

Further, the reference base for the calculation of the voltage rise ΔU is chosen as the maximal transformer busbar voltage. Conventional network planning according to the grid code [1][2] defines the maximal permissible voltage band for voltage rise in LV grids ΔU_{PV}^{perm} (e.g. 3%). By considering the maximal allowed voltage at the customer connection point of 110% according to EN50160 [3], the reference base for the calculations is $U_{base} = 110\% - \Delta U_{PV}^{perm}$ (e.g. 107%). Therefore, the variation of the transformer busbar voltage ΔU_{BB} is negative according to the chosen reference base (see Fig. 5), $\Delta U_{BB} = U_{base} - U_{BB} \leq 0$.

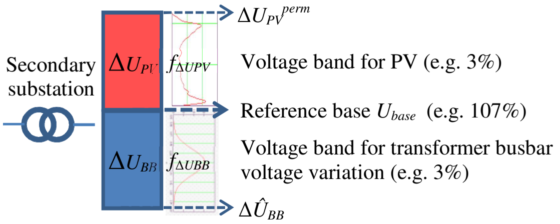

Fig. 5. Illustration of the definition of the reference base, ΔU_{PV} and ΔU_{BB}

For every combination of ΔU_{PV} and ΔU_{BB} the resulting voltage deviation will be calculated:

$$\Delta U = \Delta U_{BB} + \Delta U_{PV} \tag{4}$$

Since the ΔU_{PV} and ΔU_{BB} are assumed to be statistically independent, the frequency distribution of their sum $f_{\Delta U}(x)$ can be calculated from the convolution of their frequency distributions $f_{\Delta UBB}$ and $f_{\Delta UPV}$:

$$f_{\Delta U}(x) = (f_{\Delta UBB} * f_{\Delta UPV})(x) = \int_{-\infty}^{\infty} f_{\Delta UBB}(t) f_{\Delta UPV}(x-t)dt \tag{5}$$

A numerical exemplary representation how the multiplied empirical probabilities correspond to the voltage deviation is shown in TABLE I. and TABLE II.

TABLE I. COMBINATION OF VOLTAGE DEVIATIONS ΔU

ΔU_{BB}	ΔU_{PV}			
	0%	***1%***	***2%***	***3%***
0%	0%	1%	2%	3%
-1%	-1%	0%	1%	2%
-2%	-2%	-1%	0%	1%
-3%	-3%	-2%	-1%	0%

TABLE II. COMBINATION OF THE FREQUENCY DISTRIBUTIONS f(ΔU)

ΔU_{BB}	ΔU_{PV}			
	0%	***1%***	***2%***	***3%***
0%	0,021	0,022	0,021	0,061
-1%	0,071	0,077	0,071	0,207
-2%	0,071	0,077	0,071	0,207
-3%	0,021	0,023	0,021	0,061

With these voltage deviations ΔU and the corresponding empirical probability $f_{\Delta U}$ the empirical cumulated frequency distribution (ecdf) can be obtained (Fig. 6). The share of ecdf that exceeds ΔU_{PV}^{perm} predicts the percentage of the time (of midday hours) some PV installations will have to be curtailed in their active power infeed.

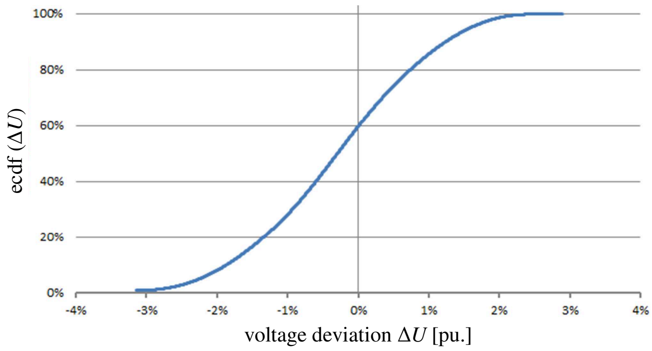

Fig. 6. Empirical cummulated probability density function (ecdf) of ΔU

E. *Determination of the probilistic reduction factor F*

To obtain the equation for the probabilistic reduction factor F stated in (1), F has to be made independent from the installed PV power. Since $F = 1$ for conventional network planning and $F < 1$ for the probabilistic approach (depending on the underlying frequency distributions), F has to be calculated from the ecdf of ΔU (Fig. 6) in a way that it does not contain the absolute value of the voltage rise any more.

The voltage deviation ΔU and the corresponding frequency distribution $f_{\Delta U}$ depend on the variation of the transformer busbar voltage ΔU_{BB} with its amplitude $\Delta\hat{U}_{BB}$ and on the assumed frequency distribution $f_{\Delta UBB}$ as well as on the voltage rise reasoned in PV infeed ΔU_{PV} with its amplitude ΔU_{PV}^{perm} and its assumed frequency distribution $f_{\Delta UPV}$.

The probabilistic Factor F can be obtained by scaling the ecdf of ΔU in respect to the PV's permissible voltage rise ΔU_{PV}^{perm}. This leads to the fact that F only depends on the convolution of the normalized frequency distributions $f_{PVpower}$ and f_{UBB} that are scaled in the aspect ratio given by the relation between the dispersion of the transformer busbar voltage to the PV's voltage $\Delta\hat{U}_{BB} / \Delta U_{PV}^{perm}$.

Since these normalized frequency distributions $f_{PVpower}$ and f_{UBB} are determined empirically, no analytical formulation of F can be specified. Instead, the probabilistic reduction factor F is shown in Fig. 7 for different relations between $\Delta\hat{U}_{BB}$ to ΔU_{PV}^{perm}.

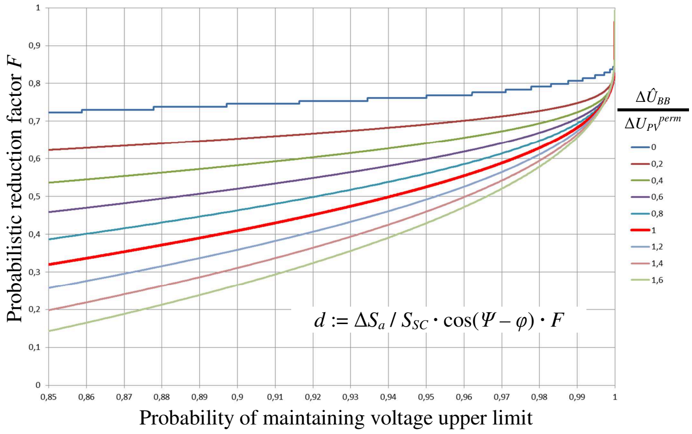

Fig. 7. Probabilistic reduction factor F for different relations $\Delta\hat{U}_{BB}/\ \Delta U_{PV}^{perm}$

The probabilistic reduction factor F can be read from Fig. 7 for the desired probability for maintaining voltage upper limit. The only parameter for the determination of F is the maximal occurrent voltage variation of the transformer busbar voltage $\Delta\hat{U}_{BB}$ in relation to permissible voltage rise caused by PV infeed ΔU_{PV}^{perm}.

Given the example that $\Delta\hat{U}_{BB}$ / ΔU_{PV}^{perm} = 1 (e.g. $\Delta\hat{U}_{BB}$ = 3% and ΔU_{PV}^{perm} = 3%) and PV infeed must be granted for 94% of the time (during midday – depending on the assumed frequency distribution for PV infeed $f_{PVpower}$), the factor $F = 0.5$ (Fig. 7) enables the doubling of the installed PV power. As a consequence, a violation of the voltage limits is predicted for 6% of the time. Therefore, P(U) control at each inverter has to assure the compliance to EN50160 [3] and maintain the 110% voltage limit.

Fig. 7 shows that all lines end up nearly vertically when the probability reaches 1. This shows that the likelihood of high transformer busbar voltages and high PV infeed at the same time is very low. The appearance of the curves with probabilities greater than 90% strongly depends on the chosen frequency distributions. Although in this area the values for F are very sensitive to the underlying frequency distributions, this area is the most interesting for probabilistic network planning. While the frequency distribution of accumulated PV infeed will vary only little from LV grid to LV grid, the variation of the transformer busbar voltage must be determined for the individual grid to obtain meaningful results with the probabilistic approach. Worst-case frequency distributions can be obtained for both PV infeed and busbar voltage, but this reduces the effectiveness of the probabilistic approach. The availability of transformer busbar voltage measurements significantly increases the accuracy of this approach.

IV. Conclusion and Outlook

The presented probabilistic approach offers an effective method for a better assessment of the PV hosting capacity. While conventional network planning is based on worst case assumptions, the probabilistic approach incorporates the frequency distribution of the transformer busbar voltages as well as the frequency distribution of the PV infeed. It is shown that the worst case assumptions will only occur very seldom at the same time. If the distribution system operator is allowed to curtail the PV infeed for short periods of time (P(U) control preferred to switching off), significant increases of the PV hosting capacity is possible.

The results of the probabilistic planning approach show that a doubling of the installed PV power in present LV grids is possible if a small amount of curtailed PV power infeed is accepted. The resulting increase in hosting capacity and the amount of curtailed energy depends on the frequency distributions of the busbar voltage and the PV infeed.

In future, the planning approach will be extended so that the energy not fed in can be derived from the selected probability.

Furthermore, the probabilistic planning approach was tested within a field test project over more than a year in a low voltage grid in Upper Austria with 142kWp PV installed which is 88% of the transformer rating. Results of the measured grid voltages and the experienced PV curtailment will be published.

Acknowledgment

The presented work conducted in the DG DemoNetz – Smart LV Grid project is funded and supported by the Austrian Klima- und Energiefonds (KLIEN) and the Austrian Research Promotion Agency (FFG).

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