Evaluation of the Distributed Generation Effect on the Power Quality of the Grid

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Abstract: Technological advancements and institutional changes in the electric power industry constantly increase the penetration level of Distributes Generation (DG) sources in the grids. The connection of new installations is subject to utility defined technical requirements for the interconnection, usually resolved at the expense of the investor. As the interest for installing new generation facilities escalates, the adoption of transparent and easily applicable technical evaluation procedures becomes more imperative. In this paper, a methodology and relevant limits are presented, which address fundamental power quality considerations and are applied by electric utility engineers. Issues addressed are the steady state and fast voltage variations, flicker and harmonic emissions. Simplified evaluation procedures are presented, largely based on the relevant IEC publications, which are suitable for application by utility engineers in practical situations.

Key-Words: Distributed Generation, Power Quality, Distribution Networks, Voltage Variations, Flicker, Harmonics.

1 Introduction

The penetration of Distributed Generation (DG) resources (wind turbines, photovoltaics, fuel-cells, biomass, micro-turbines, small hydroelectric plants etc., ranging from sub-kW to multi-MW sizes) in distribution grids is increasing world-wide.

The incorporation of DG units in the grids alters their traditional operating principle and poses new problems, regarding power quality, supply reliability and safety of operation. To speed-up the evaluation and connection process, without compromising the operating and safety requirements of the grid, proper technical evaluation procedures are required, which must be transparent, objective, widely accepted and, most important, easily applicable by utility engineers. This is now recognized by utilities and international organizations, working for the adoption of uniform technical procedures (e.g. [2-6]).

In this paper a framework of technical criteria and requirements is presented, which permits the efficient and reliable evaluation of new DG installations, regarding their connection to the grid. The methodology presented mainly concerns installations intended for connection to the MV level (typically sized above a few hundred kW). Issues addressed here are the slow and fast voltage variations, flicker and harmonic emissions. Other important considerations (protection requirements, network capacity, fault level contribution etc.) are only briefly commented, due to space limitation reasons.

2 Slow Voltage Variations

Traditionally, utilities have imposed limiting values to the acceptable steady state voltage deviations from the nominal value, both at the MV and LV levels, which should not be exceeded in normal operation of the system. During the last decade, the statistical nature of the voltage variations has been recognized and relevant norms have been issued, such as the European Norm EN 50160, [7], which imposes statistical limits, in the sense that a small probability of exceeding them is acceptable.

The evaluation procedure presented in the following ([6]) utilizes 10-min average values of the voltage and can be applied in two stages.

At a first stage, the maximum steady-state voltage change ε(%) at the PCC is evaluated, using the following relation

$$\varepsilon(\%) \cong 100\frac{S_n}{S_k}\cos\left(\psi_k+\phi\right)=\frac{100}{R}\cos\left(\psi_k+\phi\right)\le 3\,\% \qquad (1)$$

where S_n is the maximum continuous output power of the DG installation, S_k the network short circuit capacity at the PCC, ψ_k the phase angle of the network impedance and φ the phase angle of the DG output current (using generator convention). $R=S_k/S_n$ is the short circuit ratio at the PCC.

The 3% limit imposed is relatively strict because it is allocated to a single user of the network, whereas the grid voltage levels are determined by the aggregate effect of all connected consumers and generators. Notably, other European national regulations impose an even more stringent limit of 2% (e.g. [5]), a selection which is also related to the typical short circuit capacity of the grids.

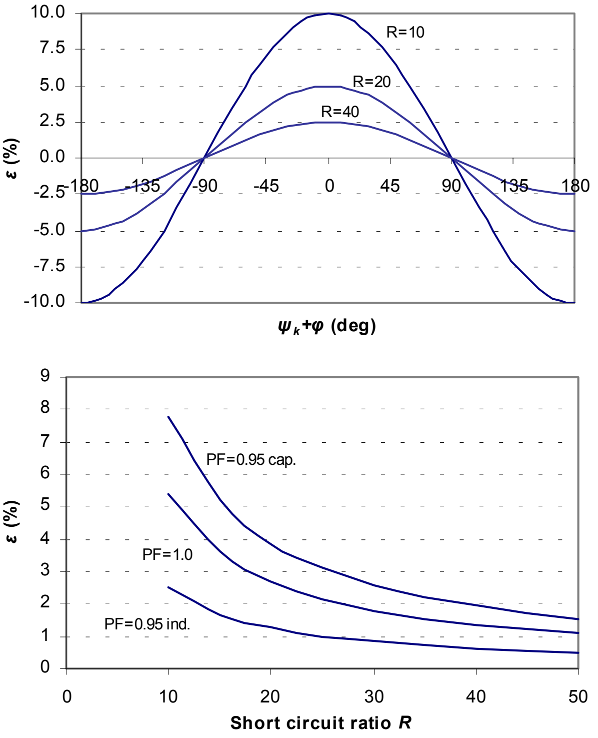

Fig. 1. Voltage change ε(%) as a function of angle $\psi_k+\varphi$, for three values of the short circuit ratio R (top diagram) and ε(%) as a function of R, for three power factor values of the DG (bottom diagram).

Depending on the grid angle ψ_k and the power factor angle φ of the installation, short-circuit ratios down to 15 or even lower may be acceptable, as illustrated in the top diagram of Fig. 1. The effect of the DG power factor on the voltage variations is also important, as it is evident in the bottom diagram of Fig. 1, drawn for $\psi_k \approx 55^o$ (overhead MV lines with ACSR-95 conductors) and DG power factor varying from 0.95 inductive to 0.95 capacitive.

The above procedure is generally not suitable for grids with high DG penetration, multiple DG installations on the same feeder, installations connected to long feeders serving significant consumer load and other special cases (e.g. long cable lines with significant shunt capacitance). In such cases, the resulting voltage variations are caused by the aggregate effect of all generating facilities and network loads. Four basic load-generation combinations should be examined:

A. Minimum load-Minimum generation
B. Minimum load-Maximum generation
C. Maximum load-Minimum generation
D. Maximum load- Maximum generation

In typical rural overhead grids, case B yields the maximum and case C the minimum voltage levels. The maximum and minimum voltages, U_{max} and U_{min}, of each node must be appropriately bounded. In [6] the following requirements are set for the steady state voltage of all nodes:

- The median voltage of each node should not deviate more than ±5% from the nominal voltage:

$$0.95 \cdot U_n \le U_{med} = \frac{U_{\min} + U_{\max}}{2} \le 1.05 \cdot U_n \qquad (2)$$

This is related with the fact that MV/LV distribution transformers are equipped with taps adjustable off-load from -5% to +5%, in steps of 2.5% and hence can compensate up to ±5% variations of the average value of the voltage.

- The variation of the voltage around its median value should not exceed ±3% of the nominal voltage:

$$2 \cdot \Delta U = U_{\max} - U_{\min} \le 0.06 \cdot U_n \qquad (3)$$

This ensures that the voltage level along at the LV network remains within the ±10% limit, after the median deviation has been corrected.

3 Rapid voltage changes – Flicker

According to the EN 50160 definition, rapid changes of the voltage are fast variations of its rms value between two consecutive levels, which are sustained for a certain (but unspecified) duration. For consistency with the definition of slow voltage changes, it is assumed that the rapid changes are much faster than the 10-min averaging interval.

Rapid voltage changes are induced either by switching operations within the premises of the DG installation (usually start/stop operations of equipment), or by the variability of the output power during normal operation. Measures of the flicker emissions are the short-term, P_{st}, and the long-term, P_{lt}, flicker severity indices ([10-12]).

Regarding switching operations, the limits imposed depend on the voltage level (LV or MV) where the customer is connected, the size of the equipment and the frequency of the operations. Taking into account the requirements of the relevant IEC documents, [12-16], the limits of Table 1 can be set for the relative (%) voltage change.

Table 1 Rapid voltage change magnitude limits

		Frequency of switching operations, r (h^{-1}: *per hour,* d^{-1}: *per day)*		
LV		$r > 1\ h^{-1}$	$2\ d^{-1} < r < 1\ h^{-1}$	$r < 2\ d^{-1}$
	Steady-state change, d_c	$\leq 3\ \%$		
	Maximum change, d_{max}	$\leq 4\ \%$	$\leq 5.5\ \%$	$\leq 7\ \%$
MV		$r > 10\ h^{-1}$	$1\ h^{-1} < r \leq 10\ h^{-1}$	$r \leq 1\ h^{-1}$
	Steady-state change, d_c	-		
	Maximum change, d_{max}	$\leq 2\ \%$	$\leq 3\ \%$	$\leq 4\ \%$

A simplified evaluation of the voltage change at the PCC during the starting (cut-in) of a DG unit can be made using the following relation:

$$d_{\max}(\%) = 100 \cdot k \cdot \frac{S_n}{S_k} = \frac{100}{R} \cdot k \tag{4}$$

For an accurate evaluation of $d_{max}(\%)$, k should be the voltage change factor $k_U(\psi_k)$, which is defined for wind turbines in IEC 61400-21, [17], and is given as a function of the grid angle ψ_k.

Flicker emissions resulting from switching operations can be calculated as ([17]):

$$P_{st} = \frac{18}{S_k} \left(\sum_{i=1}^{N} N_{10,i} \left(k_{f,i}(\psi_k) \cdot S_{n,i} \right)^{3.2} \right)^{1/3.2} \tag{5}$$

$$P_{lt} = \frac{8}{S_k} \left(\sum_{i=1}^{N} N_{120,i} \left(k_{f,i}(\psi_k) \cdot S_{n,i} \right)^{3.2} \right)^{1/3.2} \tag{6}$$

where N is the number of generators in the customer facilities operating in parallel, $S_{n,i}$ the rated capacity and $k_{f,i}(\psi_k)$ the flicker step factor of unit i (defined in [17]). $N_{10,i}$ and $N_{120,i}$ are the maximum number of switching operations that can take place in a 10-min and a 120-min interval for unit i.

In the absence of other information, a practical rule for maintaining the flicker emission limits due to switching operations is the following:

$$r \leq \frac{m}{[d_{\max}(\%)]^3}$$

where r is the maximum number of switchings per minute within the DG installation and m=5 for LV installations and 3.5 for MV installations.

At the LV level, limits for the calculated flicker indices, P_{st} and P_{lt}, are:

$$P_{st} \leq 1 \text{ and } P_{lt} \leq 0.65$$

At the MV level, the determination of exact limits is left to the utilities. In broad terms, depending on the compatibility levels (i.e. the existing disturbance level in the grid, [18]) and the internal quality objectives of the utility, the planning levels are set, which are the overall disturbance limits allowed at the planning stage (generally lower than the compatibility levels). Indicative values for the planning levels in MV systems, according to IEC 61000-3-7, are:

$$P_{st} \leq 0.9 \text{ and } P_{lt} \leq 0.7$$

The allocation of the above limits to individual producers is made according to the principles presented in the next section for harmonics and takes account of the following:

- The voltage flicker at the MV network is the combined result of emissions from loads connected at this or lower voltage level and flicker transferred from the HV grid.
- The flicker emissions from individual installations are superimposed to determine the overall voltage flicker level in the network.

The following rule is commonly applied for the summation of flicker (used for P_{lt} as well):

$$P_{st} = \sqrt[3]{\sum_i P_{st,i}^3} \tag{7}$$

During normal operation, voltage changes resulting from fluctuations of the DG output power may create flicker problems. According to IEC 61400-21, the expected flicker indices of WTs can be assessed using the flicker coefficient, $c(\psi_k, v_a)$, dependent on the average annual wind speed, v_a, of the WT installation site and the grid short circuit impedance angle, ψ_k:

$$P_{st} = P_{lt} = c(\psi_k, v_a) \frac{S}{S_k} \tag{8}$$

For the total flicker emission of a wind farm comprising N WTs, the following relation is applied:

$$P_{st\Sigma} = P_{lt\Sigma} = \frac{1}{S_k} \sqrt{\sum_{i=1}^{N} \left(c(\psi_k, v_a) \cdot S_i \right)^2} \tag{9}$$

Limits for flicker emissions during normal operation and their allocation to individual users of the system are the same as for switching operations.

4 Harmonics

The use of advanced power converters at the front end of many DG types is constantly increasing, posing harmonic control requirements for their connection to the grid. In this section, an approach based on the IEC set of standards is presented, which comprises three basic steps: First, the definition of acceptable voltage distortion limits (planning levels), second, the allocation of global harmonic voltage limits to individual producers (or consumers) and third, the determination of the corresponding current distortion limits for a specific installation.

For LV systems specific compatibility levels are given in IEC 61000-2-2, [25], and IEC 61000-3-6, [24], which also serve as planning levels, and are included in Table 2. At higher voltage levels (MV and HV), however, it is the responsibility of the utility to determine the compatibility levels in its

Odd harmonics ≠3k				Odd harmonics = 3k				Even harmonics			
Order	Harmonic voltage (%)			Order	Harmonic voltage (%)			Order	Harmonic voltage (%)		
h	LV	MV	HV	h	LV	MV	HV	h	LV	MV	HV
5	6	5	2	3	5	4	2	2	2	1.6	1.5
7	5	4	2	9	1.5	1.2	1	4	1	1	1
11	3.5	3	1.5	15	0.3	0.3	0.3	6	0.5	0.5	0.5
13	3	2.5	1.5	21	0.2	0.2	0.2	8	0.5	0.4	0.4
17	2	1.6	1	>21	0.2	0.2	0.2	10	0.5	0.4	0.4
19	1.5	1.2	1					12	0.2	0.2	0.2
23	1.5	1.2	0.7					>12	0.2	0.2	0.2
25	1.5	1.2	0.7								
>25	0.2+ $1.3\cdot\left(\frac{25}{h}\right)$	0.2+ $0.5\cdot\left(\frac{25}{h}\right)$	0.2+ $0.5\cdot\left(\frac{25}{h}\right)$								
THD: 8 % at LV, 6.5 % at MV, 3% at HV											

Table 2 planning levels for LV, MV and HV networks (IEC 61000-3-6, [24])

network and then define appropriate planning levels. For reference purposes, Table 2 summarizes indicative planning levels suggested in IEC 61000-3-6, which can be applied in the absence of more specific data.

4.1 MV systems

The coordination of harmonic emission control at the different voltage levels (LV, MV and HV) of the system requires taking account of distortion transmitted from one voltage level to the other. Hence, the distortion limit G_{hMV}, available to all installations connected to the MV system, can be found as

$$G_{hMV} = \sqrt[\alpha]{L^{\alpha}_{hMV} - \left(T_{hHM}\cdot L_{hHV}\right)^{\alpha}} \qquad (10)$$

where L_{hMV} and L_{hHV} are the MV and HV planning levels for the harmonic order h (from Table 2) and T_{hHM} the harmonic transfer coefficient from HV to MV level (ranging from below 1.0 to more than 3). α is the exponent of the harmonic summation rule:

$$U_h = \sqrt[\alpha]{\sum_i U^{\alpha}_{hi}} \text{ or } I_h = \sqrt[\alpha]{\sum_i I^{\alpha}_{hi}} \qquad (11)$$

IEC 61000-3-6, [24], suggests: α=1 for h<5, α=1.4 for 5≤h≤10 and α=2 for h>10, since harmonics of higher order tend to have random phase angles.

From G_{hMV}, the voltage distortion limit E_{Uhi} for an individual installation can then be determined, in proportion to its rated power, $S_{n,i}$:

$$E_{Uhi} = G_{hMV}\sqrt[\alpha]{\frac{S_{n,i}}{S_t}} = G_{hMV}\sqrt[\alpha]{s_i} \qquad (12)$$

where S_t is the total «feeding capacity» of the network (e.g. equal to the rated MVA of the feeding transformer). The ratio S_i can also be interpreted as the ratio of the connected equipment rated power to the total capacity of the distorting equipment in the network.

It is common practice in harmonic studies to regard the connected equipment as harmonic current sources (although this may not be correct in certain cases), whereas the limits discussed previously refer to the harmonic distortion of the system voltage. In order to relate these quantities, the system harmonic impedance Z_h at the PCC is needed. Then:

$$U_{hi} = Z_h \cdot I_{hi} \le E_{Uhi} \Rightarrow I_{hi} \le E_{Ihi} = \frac{E_{Uhi}}{Z_h} \qquad (13)$$

where U_{hi} and I_{hi} are the h-order harmonic voltage and current due to installation i and E_{Uhi}, E_{Ihi} the respective limits allocated to this installation.

For MV systems, the harmonic impedance Z_h has to be calculated on a per-case basis, since no standardized reference impedance is available. A simplified approach can be established with reference to Fig. 2, where all network capacitance is aggregated at the MV busbars and any possible resonance in the HV system is ignored.

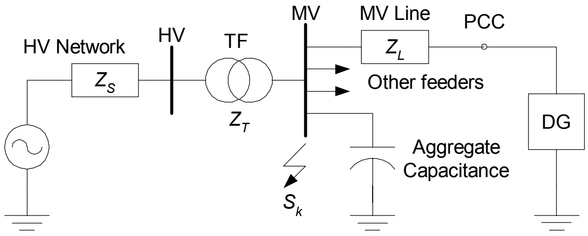

Fig. 2. MV network equivalent for simplified harmonic emission evaluation

For systems without significant capacitance and no PFC correction capacitors or filters in the DG installations:

$$Z_h \approx h \cdot X_k \qquad (14)$$

where X_k is the fundamental frequency inductive component of the short circuit impedance at the PCC.

The aggregate capacitance in Fig. 2 accounts for the first order parallel resonance with the upstream system (but not for possible higher order resonances).

If all resistances and system loads in Fig. 2 are ignored, the resonant frequency f_r and the respective harmonic order h_r (not necessarily integer) are given by

$$f_r = f_1\sqrt{\frac{S_{kS}}{Q_c}} \Rightarrow h_r = \frac{f_r}{f_1} = \sqrt{\frac{S_{kS}}{Q_c}} \qquad (15)$$

where S_{kS} is the short circuit capacity at the MV busbars of the HV/MV substation and Q_c is the total capacitive reactive power of the MV network. A rough and conservative estimation of Z_h (usually providing results on the safe side) is then given by the "envelope impedance curve" of IEC 61000-3-6, shown in Fig. 3. The resonant amplification factor, k_r, of the system impedance at the PCC typically varies between 2 and 5 in public distribution networks ([24]), depending mainly on the damping effect of the system loads.

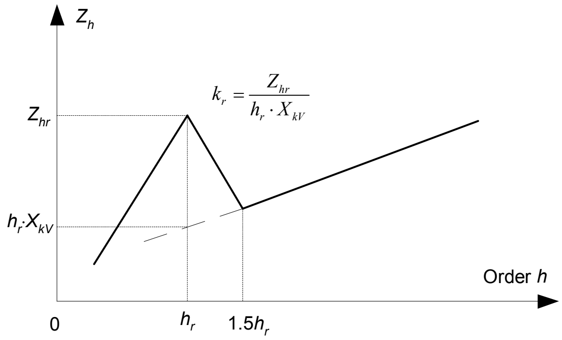

Fig. 3. System harmonic impedance approximation, using the «envelope impedance curve» (IEC 61000-3-6, [24]).

For installations with filters or significant PFC capacitance, in more complex networks or when resonant conditions exist in the HV network, the approach presented above may not be suitable. Manual computation of Z_h is possible in certain cases (IEC 61000-3-6 provides relevant examples) but the application of harmonic load flow software is recommended, since the harmonic distortion of the voltage may be maximum at points other than the equipment PCC.

An even simpler "first stage" evaluation, introduced in [4], sets a limit directly for the harmonic current emissions:

$$I_h \leq L_h \cdot S_k \cdot \frac{S_n}{S_t}$$

where S_n and S_t are the same as in eq. (12) and L_h is the harmonic current limit per MVA of the system short circuit capacity. For a MV grid with 20 kV nominal voltage, the values from Table 3 can be applied. For other grid voltages, the applicable limits vary in inverse proportion to the voltage. The limits of Table 3 have been derived with very conservative assumptions regarding the harmonic resonance conditions in the grid and therefore are quite strict.

Table 3 harmonic current limits per MVA of system capacity (20 kV grid)

Order, h	L_h, (A/MVA)	Order, h	L_h, (A/MVA)
3	0.050	13	0.017
5	0.060	17	0.010
7	0.040	19	0.008
9	0.008	23	0.005
11	0.025	25	0.004
h even or h=15,21or h >25 :		0.03/h	

4.2 LV systems

The principles outlined in the previous section for MV systems are also applicable to the LV level. However, for LV systems IEC 725, [26], establishes a reference system impedance, permitting thus the direct determination of harmonic current limits. Based on IEC 61000-3-2 ([22]), the limits shown in Table 4 can be applied for DG units with rated current ≤ 16 A/phase (Class A).

Table 4 Harmonic current limits for LV equipment with rated current ≤ 16 A

Odd harmonics		Even harmonics	
h	$I_{h,max}$ (A)	h	$I_{h,max}$ (A)
3	2.30	2	1.08
5	1.14	4	0.43
7	0.77	6	0.30
9	0.40	≥8	$0.23 \cdot (8/h)$
11	0.33		
13	0.21		
≥15	$0.15 \cdot (15/h)$		

For DG units with a rated current between 16 and 75 A/phase, the limits of IEC 61000-3-4 ([23]) are applicable.

5 Conclusion

The criteria and procedures presented are part of the Greek utility guide, [6], and are largely based on the set of relevant IEC publications. The requirements and evaluation procedures introduced ensure that the connection of DG resources will not adversely affect the power quality and safety of operation of the grid.

It is expected that technological advancements in the following years will call for another update of the evaluation methodologies. For instance, active front end converters, with load balancing, flicker cancellation and active filtering capabilities, will soon find their way in commercial DG equipment. Apart from the core technical issues, several other market and regulatory factors will affect critically the degree of future DG penetration, such as tariffication policies, metering practices, pricing of power quality characteristics etc.

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