# Modelling and Control of Photovoltaic Inverter Systems with Respect to German Grid Code Requirements

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***Abstract*—The increasing share of renewable energies leads to the point where system operators require accurate modelling of generation units for planning extensions in their power system. Consequently manufacturers of renewable energy sources like wind power, photovoltaic or biomass are obliged to prove the electrical properties of their units in field test as well as validate the performance of simulation models based on the measurements.**

**In Germany standards and technical guidelines were defined which describe the procedure for the testing of the generation units and the validation of the simulation models. Independent certification bodies have to supervise the testing and analyze the performance of the models to determine whether or not the generation unit fulfills the German Grid Code Requirement.**

**In this paper the authors describe the different requirements of the German grid code with focus on the dynamic requirements. Additionally the testing setup and the methodology for comparing measurements with simulation are explained. Furthermore the control of a three-phase inverter system for photovoltaic application is derived. Finally simulation results of a photovoltaic inverter system are presented in order to demonstrate the behavior during short term grid disturbances.**

***Index Terms*—Control, Fault Ride Through, Grid Codes, Three-Phase Inverter, Modelling, Photovoltaic, Renewable Energy**

## I. Introduction

Large scale photovoltaic (PV) systems are one part of the efforts of national governments to increase the share of renewable energy sources in the energy mix. Most of the existing PV systems are small units installed in households and connected to the low voltage level. By contrast large scale PV units are connected to the medium or even to the high voltage level. As a consequence large scale PV systems affect the power flow in the interconnected network and so they have to fulfill certain requirements regarding their electrical properties. According to German regulations these requirements for PV application are equivalent to all renewable energy based generation units like wind power or biomass. The regulations contain requirements concerning the active and reactive power control, the power quality, the system security functions and behavior during grid disturbances. These regulations are designed to achieve a reliable and secure grid integration of renewable energies sources. Usually detailed system study takes place before large units are connected to the grid. For these investigations accurate simulation models are needed.

The purpose of the German certification rules is to gather information about electrical properties of a unit by measurements during field or laboratory testing and to utilize these measurements for creating simulation models which describe the behavior of the unit as exactly as possible. Based on certificates for certain units or types simulation models for larger systems will have to be developed. Such system can be an onshore or offshore wind farm consisting of a certain number of wind turbines or a large scale PV Systems consisting of several PV inverter systems. Unit and system certificates are highly desired by the manufacturers these days due to the necessity for the grid integration as well as for marketing interests.

## II. Technical Requirements

Grid codes with new regulations for generation units had to be published all over the world in the last years. In Germany it is distinguished between conventional generation units with directly connected synchronous generators and generation units of renewable energy units like wind power, PV or biomass. The regulations contain requirements concerning the active and reactive power control, the power quality, the security functions and the behavior during grid disturbances. The active power requirements include the verification of maximum active power which can be provided by the unit, the verification of active power reduction in case of a defined setpoint change or in case of overfrequency and the verification of the active power gradient after restarting the unit. The reactive power requirements imply the verification of the reactive power limits of the unit. This will be tested for the inductive as well for the capacitive limit in step changes of the active power configuration. Additionally the verification of reactive power provision in case of a defined setpoint change, the reactive power step response of the system and the steady state voltage control due to reactive power provision are required in the technical regulations. Regarding the power

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quality and the interaction between the power system and the generation unit regulations and limits for flicker and harmonics exist in order to obtain a reliable operation of the power system. Security functions needed to be implemented and tested during different operating points of the generation unit. Therefore the behavior of the generation unit below or above certain voltage and frequency thresholds is part of grid code requirements.

Generation units should stay connected to the power system during disturbances. Additionally, the reactive current control of the generation unit must be used to support the grid voltage in case of short term voltage drop or increase. In order to support the grid voltage, there are strict stipulations concerning the time variation of the injected reactive current following a step voltage change.

Fig. 1 describes the Fault Ride Through (FRT) requirements of the German grid code which currently forms the basis for testing by the certification body. It is required that the unit stays connected to the power system for 150 ms in case of a voltage dip to 0 p.u. (so called Zero Voltage Ride Through). With modern protection devices the fault durations are normally in a range of some hundred milliseconds or less. In spite of this voltage dips with durations of up to 1.5 s according (the red curve in Fig. 1) will be tested. Usually the FRT testing procedure is separated into 4 parts with the following residual (fault) line-to-line voltages a) $U_{res} \leq 0.05$ p.u., b) $0.2 \leq U_{res} \leq 0.25$ p.u., $0.45 \leq U_{res} \leq 0.55$ p.u. and $0.7 \leq U_{res} \leq 0.8$ p.u. with corresponding duration for each. All tests should be performed for symmetrical, three phase fault as well as for unsymmetrical, two phase faults.

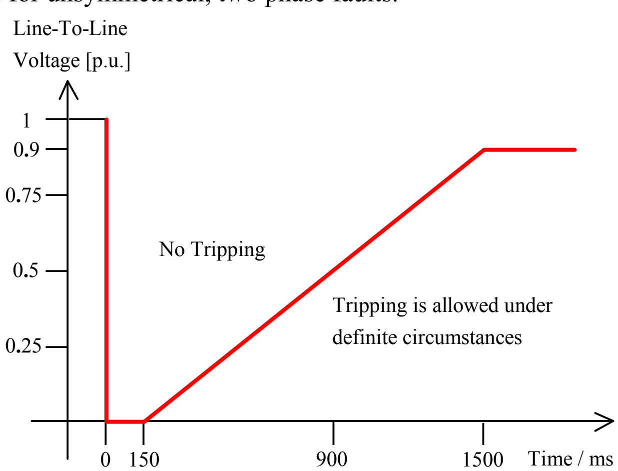


Fig. 1. Fault Ride Through Characteristic

Additionally to the FRT capability the German grid code requires the support of grid voltage during fault conditions by the generation units. Fig. 2 describes the required behavior during voltage drop or increase. In case of overvoltage the unit has to inject inductive reactive current while during voltage drops the unit has to feed in capacitive reactive current. The voltage $\Delta U$ is defined as difference between the pre-fault voltage and the voltage during the fault. The voltage control may include a dead band of ±0.1 p.u. and has a setting range for the gain of 0...10 p.u. with a default value of 2 p.u. To allow the controller also to react to small voltage deviations and to speed up the response a continuous voltage control without dead band can be favorable. Units must be able to inject at least 1 p.u. reactive current during symmetrical faults according to the proportional characteristic of the voltage controller. For unsymmetrical fault the generation unit has to provide at least 0.4 p.u. positive sequence reactive current. The two characteristics in Fig. 2 describe two different German grid codes. The red curve explains the requirements according to the Transmission Code 2007 [5] and the Medium Voltage Directive of 2008 [6] while the blue curve illustrates the demands of the “Ordinance on System Services by Wind Energy Plants” (SDL Wind 2009) [7]. These requirements for symmetrical and unsymmetrical faults are related to the positive sequence of the current. Concerning the negative sequence current injection there are no requirements yet. Hence the negative sequence current is usually suppressed to zero.

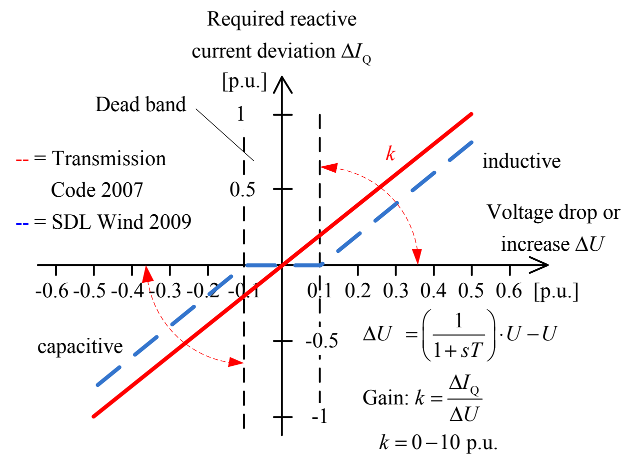


Fig. 2. Voltage Control Characteristic

Fig. 3 shows the reactive current injection as a function of time during the short term voltage support. Hereby a rise time of less than 30 ms and a settling time of less than 60 ms are required. A tolerance band between +20 % and -10 % of the dynamic current reference value is considered. Rise time describes the time at which the reactive current reaches the tolerance band for the first time while the settling time implies the time needed for the reactive current to remain within the limits of the tolerance band. This timing characteristic only refers to the positive sequence quantity.

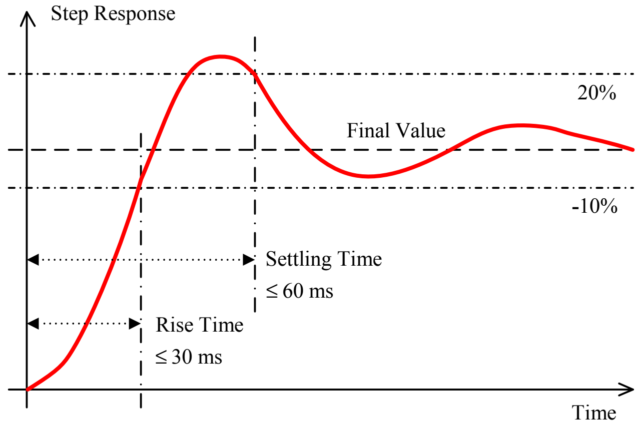


Fig. 3. Step Response of the Reactive Current Injection during FRT

## III. Testing Setup and Data processing

Regarding the behavior during grid disturbances FRT tests of PV inverter systems can be performed by a testing setup described in Fig. 4. Hereby an inductive voltage divider is used to create defined voltage dips to the generation unit. Further testing setups are possible, which are already developed and can be used for the FRT testing (e.g. controlled grid simulators). The residual voltage depends on the ratio between X1 and X2. This testing device is designed to reduce the voltage at the terminals of the generation unit to a defined level within a short period of time. The effect of FRT testing to the connected power system should be limited due to the configuration of the voltage divider coordinated with the short circuit capacity of the interconnected power system.

During normal operation, switch S1 is closed and switch S2 is open. In order to reduce the impact of the short circuit on the grid, switch S1 is opened and the series reactance X1 is connected between the grid and generation unit in order to reduce the short circuit capacity at the point of interconnection. After all transients have died down, the short circuit impedance X2 is connected in parallel to the generation unit by closing switch S2. This causes the voltage dip. After a certain time period depending on the desired duration of the dip S2 is opened again. The voltage at the generation unit recovers and after decaying all transients S1 is closed again and normal operation is restored.

Three-phase PV inverter systems are connected to the low voltage side. The testing device can also be configured for the low voltage level but can also be designed for the medium voltage level. Therefore an additional transformer between medium and low voltage side is necessary. The measurement point for analyzing the electrical quantities of the generation unit is always located at the low voltage terminals of the PV inverter system. The DC source can be implemented as a rectifier controlling and emulating the power flow coming from the PV cells.

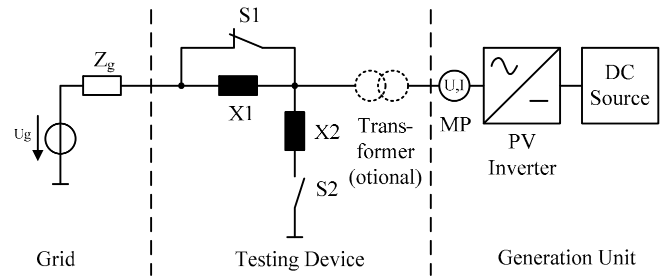


Fig. 4. Principle setup for FRT testing of a PV inverter system

Three phase measurements of the phase voltages and currents at the measurement point MP are necessary for evaluating the dynamic behavior of the generation unit. To verify the system response to the aforementioned grid requirements, the measured data must be further processed to calculate the quantities of voltage, active and reactive power and active and reactive current as positive sequence fundamental frequency components. One procedure to calculate the positive sequence based on the measurement of instantaneous voltages and currents is explained in IEC 61400-21 Annex C [8]. Hereby the following equations can be used

$$u_{\mathrm{k,cos}} = \frac{2}{T}\int_{t-T}^{t} u_{\mathrm{k}}(t)\cos(2\pi f_1 t)\mathrm{d}t \tag{1}$$

$$u_{\mathrm{k,sin}} = \frac{2}{T}\int_{t-T}^{t} u_{\mathrm{k}}(t)\sin(2\pi f_1 t)\mathrm{d}t \tag{2}$$

where $k = a,b,c$ and $f_1$ is the fundamental frequency.

$$u_{1+,\cos} = \frac{1}{6}[2u_{a,\cos} - u_{b,\cos} - u_{c,\cos} - \sqrt{3}(u_{c,\sin} - u_{b,\sin})] \tag{3}$$

$$u_{1+,\sin} = \frac{1}{6}[2u_{a,\sin} - u_{b,\sin} - u_{c,\sin} - \sqrt{3}(u_{b,\cos} - u_{c,\cos})] \tag{4}$$

The positive sequence current components $i_{1+,\cos}$ and $i_{1+,\sin}$ can be calculated by the same equations like the voltage components $u_{1+,\cos}$ and $u_{1+,\sin}$. The active and reactive powers of the fundamental positive sequence are then

$$P_{1+} = \frac{3}{2}(u_{1,\cos}\cdot i_{1,\cos} + u_{1,\sin}\cdot i_{1,\sin}) \tag{5}$$

$$Q_{1+} = \frac{3}{2}(u_{1,\cos}\cdot i_{1,\sin} - u_{1,\sin}\cdot i_{1,\cos}) \tag{6}.$$

The root mean square (rms) values for active and reactive currents of the fundamental positive sequence are

$$I_{\mathrm{P1+}} = \frac{P_{1+}}{\sqrt{3}\cdot U_{1+}} \tag{7}$$

$$I_{\mathrm{Q1+}} = \frac{Q_{1+}}{\sqrt{3}\cdot U_{1+}} \tag{8}.$$

The rms phase to phase voltage of the fundamental frequency component can be calculated by the following equation

$$U_{1+} = \sqrt{\frac{3}{2}(u_{1+,\sin}^2 + u_{1+,\cos}^2)} \quad (9).$$

The integration over one period of the fundamental frequency of (1) and (2) results in a considerable delay which will be compensated by subtracting the cycle time of the fundamental from the calculated results for rise and settling time.

## IV. Control of the Three-Phase Inverter

A three-phase PV inverter usually consists of an IGBT-based six pulse bridge. Fig. 5 shows the basic configuration of such inverter system. Each IGBT module is controlled by Pulse Width Modulation signals coming from the controller. The inverter and its control are mainly responsible for the electrical behavior of the unit. Functionalities which needed to be performed by the inverter are the Maximum Power Point Tracking and the decoupled control of active and reactive current and thus active and reactive power. In the following subchapter a classical two-dimensional current control aligned to the grid voltage for the positive sequence with an outer DC voltage controller is described. Hence there are no requirements for the negative sequence the target of the control is to suppress the negative sequence current totally. Therefore the negative sequence of the voltage has to be calculated quickly and combined with the positive sequence of the inverter voltage.

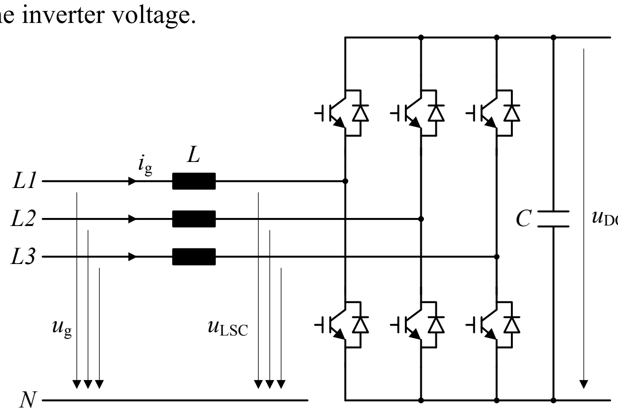


Fig. 5. Principle arrangement of a PV inverter

From the loop equation for the voltages in the circuit described in Fig. 5 the following equation (10) is derived. The grid voltage is represented by $u_g$ while the controlled output voltage of the converter is $u_{LSC}$. The voltage drop over the choke can be calculated using the inductance of choke $L$ and the current $i_g$. Hereby the resistive part of the choke will be neglected because the Q factor of the choke is ordinarily small.

$$\begin{pmatrix} u_{g,L1} \\ u_{g,L2} \\ u_{g,L3} \end{pmatrix} = L \cdot \frac{d}{dt} \begin{pmatrix} i_{g,L1} \\ i_{g,L2} \\ i_{g,L3} \end{pmatrix} + \begin{pmatrix} u_{LSC,L1} \\ u_{LSC,L2} \\ u_{LSC,L3} \end{pmatrix} \quad (10)$$

Rewriting equation (10) in complex quantities the following equation (11) for the positive sequence with the index + can be derived where the reference frame of each quantity is chosen arbitrarily with the notation $\angle 0$ and transformed into the per-unit system.

$$\underline{u}_{g,+}^{\angle 0} = l \cdot \frac{d}{dt} \underline{i}_{g,+}^{\angle 0} + \underline{u}_{LSC,+}^{\angle 0} \quad (11)$$

The reference frame of the described control is aligned to the grid voltage. Therefore the angle $\Theta_g$ can be calculated by the trigonometric function of equation (12) where $\alpha$, $\beta$ represents the alpha and beta components of the space vector of the positive sequence grid voltage.

$$\Theta_g = \arctan\left(\frac{u_{g,\beta,+}}{u_{g,\alpha,+}}\right) \quad (12)$$

Equation (11) will be transformed in a reference frame rotating with the angle $\Theta_g$ described by the notation $\angle u_g$. The following two equations (13) and (14) already separated into the direct and quadrature axis components where $\omega_0$ is the radian frequency of the grid voltage.

$$u_{g,d,+}^{\angle u_g} = l \cdot \frac{d i_{g,d,+}^{\angle u_g}}{dt} - \omega_0 l \cdot i_{g,q,+}^{\angle u_g} + u_{LSC,d,+}^{\angle u_g} \quad (13)$$

$$u_{g,q,+}^{\angle u_g} = l \cdot \frac{d i_{g,q,+}^{\angle u_g}}{dt} + \omega_0 l \cdot i_{g,d,+}^{\angle u_g} + u_{LSC,q,+}^{\angle u_g} \quad (14)$$

It follows from above (13), (14) that the reference voltages of the inverter can be described by the following equations

$$u_{LSC,d,+}^{\angle u_g} = u_{g,d,+}^{\angle u_g} - u'^{\angle u_g}_{LSC,d,+} + \omega_0 l \cdot i_{g,q,+}^{\angle u_g} \quad (15)$$

$$u_{LSC,q,+}^{\angle u_g} = u_{g,q,+}^{\angle u_g} - u'^{\angle u_g}_{LSC,q,+} - \omega_0 l \cdot i_{g,d,+}^{\angle u_g} \quad (16)$$

where the two current PI-controllers can be derived as follows

$$u'^{\angle u_g}_{LSC,d,+} = K_P\left(1 + \frac{1}{Ts}\right) \cdot (i_{g,d\_ref,+}^{\angle u_g} - i_{g,d,+}^{\angle u_g}) \quad (17)$$

$$u'^{\angle u_g}_{LSC,q,+} = K_P\left(1 + \frac{1}{Ts}\right) \cdot (i_{g,q\_ref,+}^{\angle u_g} - i_{g,q,+}^{\angle u_g}) \quad (18).$$

The PI controllers have to adjust the output voltage of the inverter in case of a setpoint change quickly. In steady state the feed forward and the grid voltage terms of (15) and (16) lead already to stable conditions in the control loop. Only errors in system parameters need to be compensated by the PI controller in steady state. The corresponding principle bloc diagram of the inner current control loop of the inverter is described in Fig. 6.

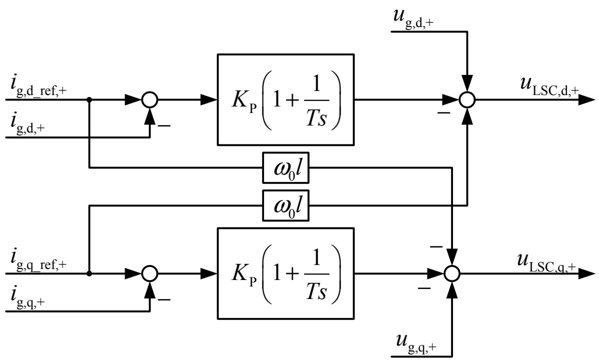


Fig. 6. Bloc diagram of the positive sequence current control

In order to suppress the negative sequence current in unbalanced steady state or dynamic conditions the negative sequence grid voltage with the index - has to be merged with the positive sequence reference voltage of the inverter. Fig. 7 illustrates the coupling of the negative sequence space vector with the space vector of the positive sequence. The resulting reference inverter voltage contains the positive and the negative sequence voltage.

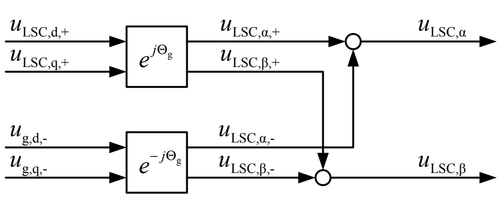


Fig. 7. Calculation of the reference inverter voltage

Positive sequence active and reactive power of the inverter can be written in the following equations where $p_+$ and $q_+$ are expressed as rated values.

$$p_+ = u_{g,d,+}^{\angle u_g} \cdot i_{g,d,+}^{\angle u_g} + u_{g,q,+}^{\angle u_g} \cdot i_{g,q,+}^{\angle u_g} \tag{17}$$

$$q_+ = u_{g,q,+}^{\angle u_g} \cdot i_{g,d,+}^{\angle u_g} - u_{g,d,+}^{\angle u_g} \cdot i_{g,q,+}^{\angle u_g} \tag{18}$$

Due to the alignment of reference frame on the grid voltage the quadrature components of $u_g$ is equal to zero in case of symmetrical conditions. It follows that direct component $i_{g,d,+}$ and the quadrature component $-i_{g,q,+}$ are proportional to the active and reactive power. The power balance between the DC and the AC circuit can be described by the following equation without considering losses inside the inverter system

$$p = u_{DC} \cdot i_{DC} \approx u_{g,d,+}^{\angle u_g} \cdot i_{g,d,+}^{\angle u_g} \tag{19}$$

It is obvious that the DC voltage is influenced by the direct component $i_{g,d,+}$ of the inverter system. The reference value of the direct component current controller is consequently the output of the outer DC voltage controller where the reference value of the DC voltage results from the MPP Tracking.

$$i_{g,d\_ref,+}^{\angle u_g} = K_P\left(1+\frac{1}{Ts}\right) \cdot (u_{DC\_ref} - u_{DC}) \tag{20}$$

The principle positions and structure of the complex phasors of a three-phase PV inverter system is illustrated in Fig. 8.

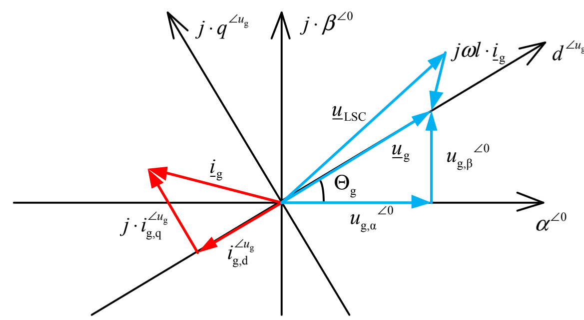


Fig. 8. Principle phasor diagram of a PV inverter

## V. Simulation Results

In the following chapter results carried out by EMT simulation models based on Matlab/Simulink describe the dynamic behavior of PV inverter systems during short term grid disturbances. Therefore an inverter system with the nominal active power of 150 kW was designed. The system is connected to the low voltage level with a nominal voltage of 270 V which means that the nominal current of the system is 320 A. The connected low voltage grid has a short circuit power of 10 MVA. The grid disturbances are created by an inductive voltage divider described in chapter IV. The short circuit ratio between FRT testing device and generation unit is 10. The instantaneous values are measured at the point between generation unit and testing device. Based on these instantaneous values the positive and negative sequences are computed according to the calculation method of IEC 61400-21 described in chapter IV.

In this chapter three different fault conditions and the response of the inverter system are visualized. In Fig. 9 a symmetrical three-phase fault to 50 % of the nominal voltage with a duration of 150 ms is illustrated. Usually this FRT testing requires a longer duration, but due to the intention of showing the instantaneous values of the system the duration of the fault is reduced. From the figures it is clear that the conditions during the fault are stable so that the inverter can withstand this fault for a longer period of time.

In Fig. 10 a direct symmetrical fault (with a residual voltage of 0 % of the nominal voltage) is shown. Hereby the inverter stays connected to the power system and is injecting capacitive reactive current. The calculation method according to IEC 61400-21 has the disadvantage that a very small voltage system leads to an error in separating active and reactive power components as well as the active and reactive current component. So in Fig. 8 only the positive sequence of the apparent power and current is visualized.

Fig. 11 describes an unsymmetrical two-phase fault and the response of the inverter system. The voltage of the two affected phases is reduced to 0 % of the nominal voltage. So the positive sequence of the voltage is reduced to 50 % while

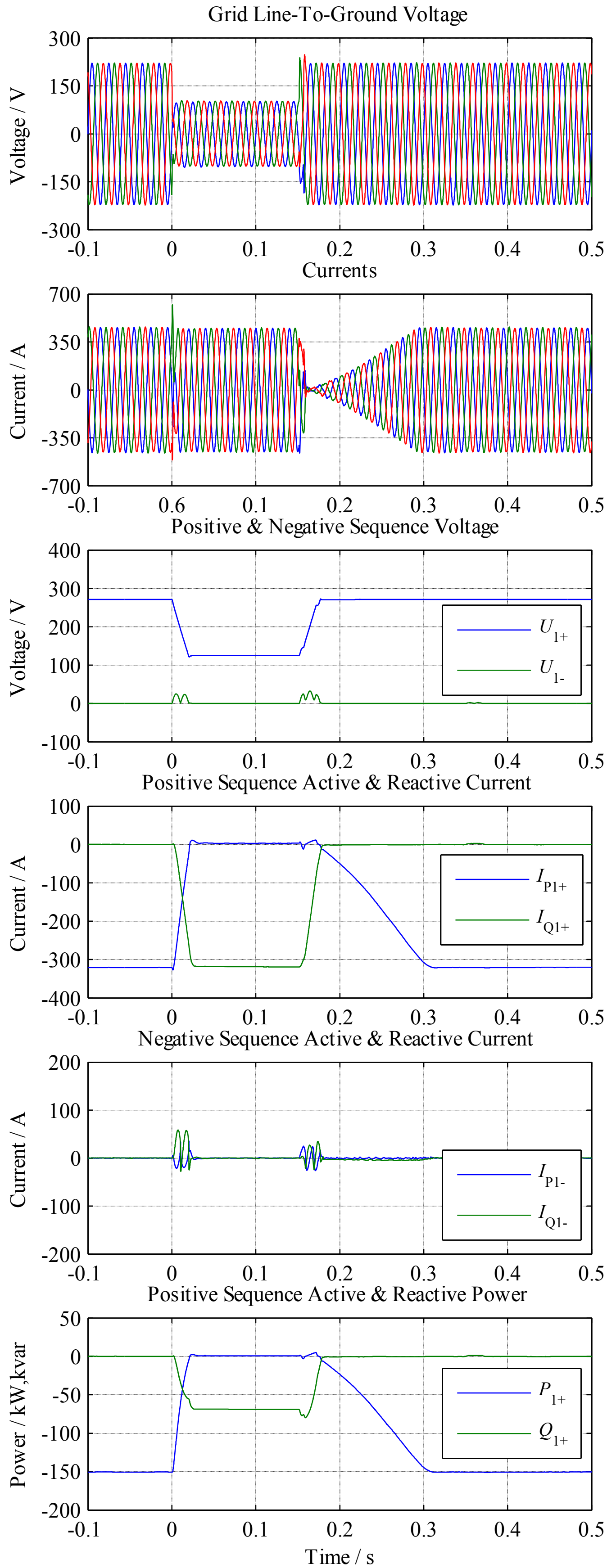


Fig. 9. Simulation results of a FRT Test with a symmetrical voltage drop to 50 % of the nominal voltage

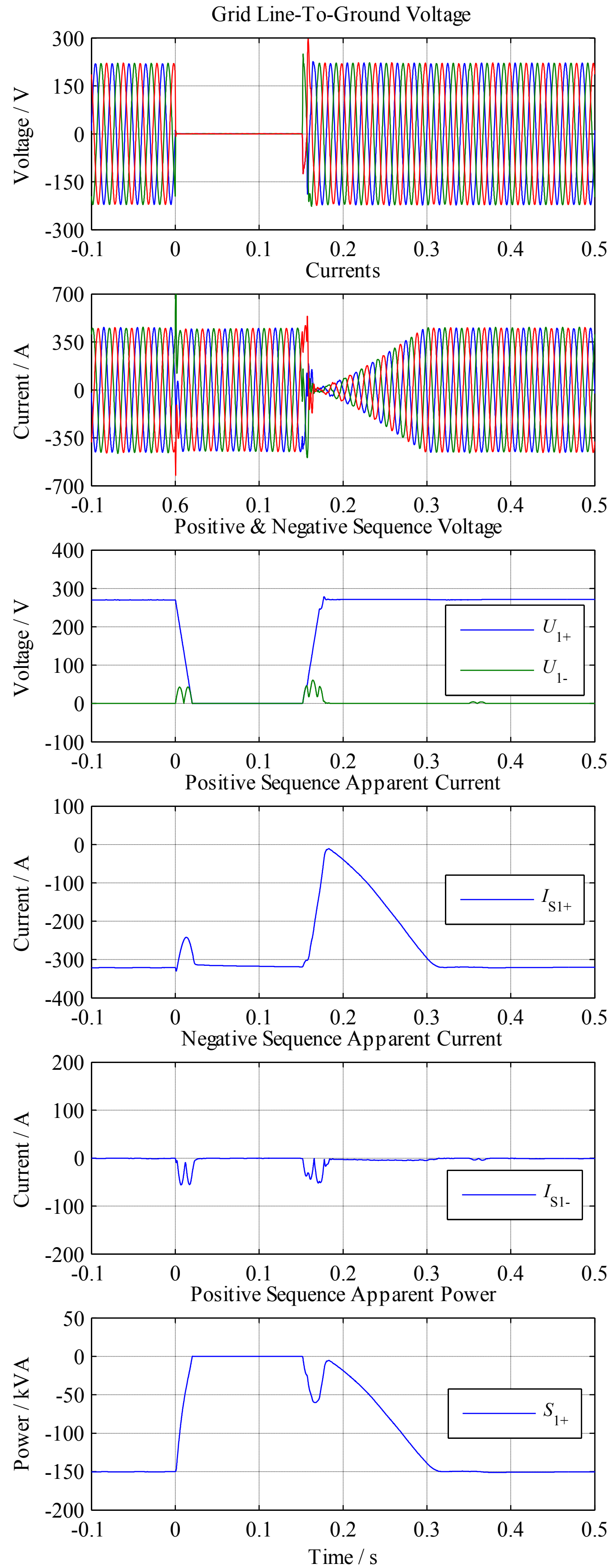


Fig. 10. Simulation results of a FRT Test with a symmetrical voltage drop to 0 % of the nominal voltage

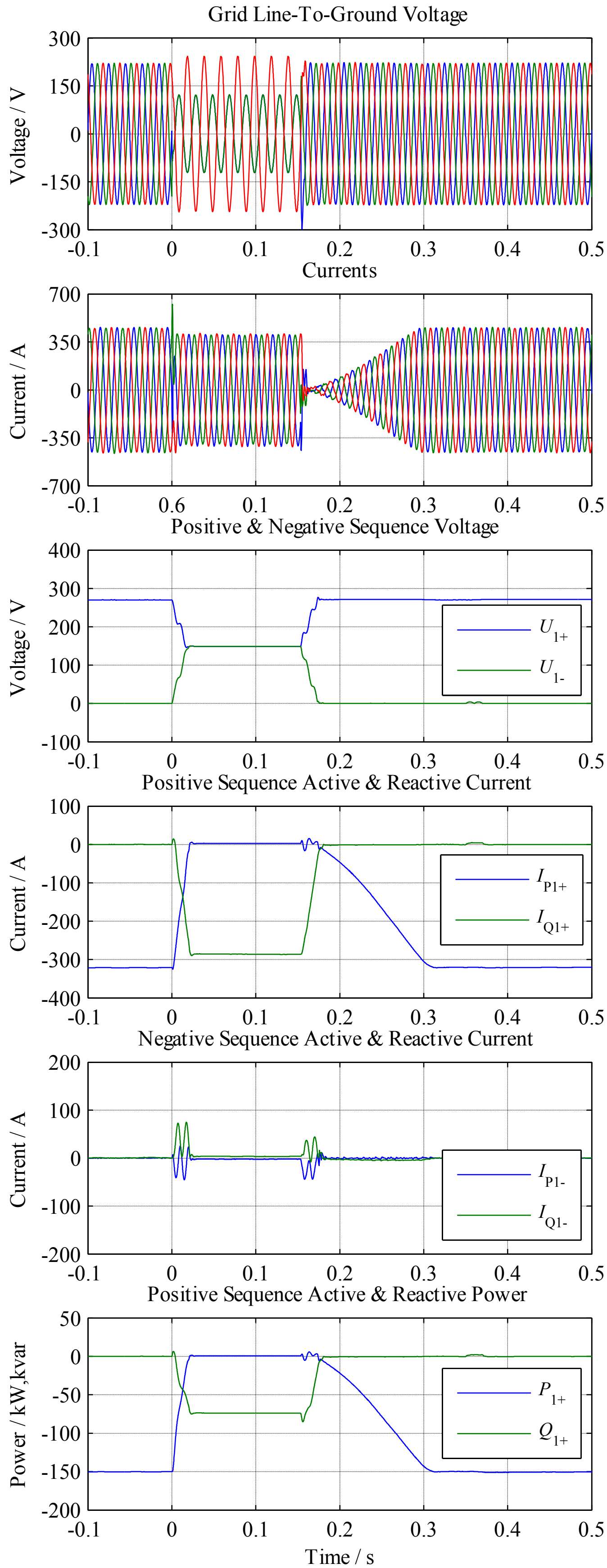


Fig. 11. Simulation results of a FRT Test with an unsymmetrical 2-phase-fault with voltage drop to 0 % of the nominal voltage in the affected phases

a negative sequence of 50 % occurs during this unsymmetrical fault. Although there is only a requirement to inject 0.4 p.u. of the positive sequence capacitive reactive current the inverter has the capability to provide up to 1 p.u. of reactive current during unbalanced conditions. The negative sequence current is suppressed totally although a negative sequence of approximately 50 % occurs in the voltage system.

## VI. Conclusion

In this paper the authors have introduced the current requirements of German grid codes which are valid for generation units of renewable energy sources like wind power, PV or biomass. Furthermore the procedure for performing the FRT testing for PV inverter systems and the methodology for calculating the positive sequence quantities based on instantaneous values were described.

The control of the inverter system is to a large extent responsible for the behavior in steady state as well as in dynamic operational mode of PV application. Hence the authors introduced the basic control structure of the inverter systematically. Consequently EMT simulation results illustrate the dynamic behavior of a PV inverter system during grid disturbances and show the good performance of this control. In the three case studies the simulation results illustrate that modern PV application systems can meet the requirements of the German grid code. During symmetrical faults the PV inverter can ride through any voltage dips. Even zero voltage ride through is possible with an appropriate control strategy. Additionally the inverter is capable of injecting a considerable positive sequence capacitive reactive current to support the dipping voltage. During unsymmetrical fault events the PV inverters are also able to ride through the unbalanced conditions and suppress a negative sequence current totally. The injected positive sequence capacitive reactive current during unsymmetrical faults can be 1 p.u. Regarding the timing of the voltage control the simulation results emphasize that PV inverter system can meet the requirement of the rise and the settling time of German grid codes by using fast control actions during fault conditions.

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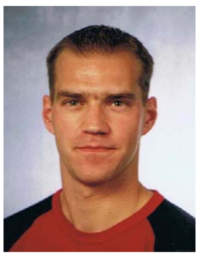
## VIII. Biographies



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