Impact of Fault Ride-Through and Dynamic Reactive Power Support of Photovoltaic Systems on Short-Term Voltage Stability

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Abstract—This paper investigates the impact of the Fault Ride-Through (FRT) capability and the dynamic reactive power support of large-scale Photovoltaic (PV) systems according to the newly proposed German Grid Code (GGC) on short-term voltage stability. The PV system is based on a generic model and realistic parameters are used that are determined in consultation with a manufacturer. In this context, improvements of the generic PV system model are stated. The GGC requirements are compared with several other control schemes for dynamic reactive power support, such as the adjusted control mode, i.e., the active and reactive current is calculated according to the grid impedance angle. The results show that the GGC requirements help the power system to avoid short-term voltage instability. Moreover, the requirements lead to an enhanced dynamic performance in terms of voltage support and recovery. Only the adjusted control mode shows a slightly better performance than the GGC. However, as this control scheme needs on-line information about the grid impedance angle, and therefore, additional infrastructure for the measurements, it is also more expensive. Hence, it can be concluded that the GGC requirements, with respect to FRT and dynamic reactive power support, are reasonable from a technical and economical point of view.

Index Terms—Fault-Induced Delayed Voltage Recovery (FIDVR), Low Voltage Ride-Through (LVRT), Dynamic Voltage Support (DVS), reactive power control, Induction Motors (IMs), Photovoltaic (PV) generation, power system stability.

I. INTRODUCTION

Presently, the electrical power system is undergoing fundamental changes due to the increasing penetration of Inverter Based Generation (IBG), i.e., wind and Photovoltaic (PV) generation. The dynamic characteristics of these technologies are different from conventional synchronous generators that may change the performance of the power system following disturbances. Therefore, dynamic studies are required in order to evaluate the impact of IBG on power system stability.

Recently, several studies have investigated the impact of IBG, i.e., PV systems, on transient stability \cite{1, 2}, small-signal stability \cite{3} and frequency stability \cite{1, 2}. Nevertheless, only a few studies have investigated the impact of large-scale PV systems on short-term voltage stability \cite{4}.

The new contribution of this paper is the comparison of the newly proposed German Grid Code (GGC) requirements for the high-voltage network \cite{5} with other control modes considering the impact of Fault Ride-Through (FRT) and dynamic reactive power support of large-scale PV systems on short-term voltage stability. Moreover, a realistic parameter set for the Western Electricity Coordinating Council (WECC) generic PV system model \cite{6} is provided. Furthermore, improvements of the WECC generic PV system model are given. Finally, recommendations for the dynamic reactive power support are stated to improve the overall performance of the system.

Short-term voltage instability is also known as transient voltage collapse and it is a major threat in power system operation as it may trigger cascading failures and/or wide-spread blackouts. The driving force is the tendency of aggregated Induction Motor (IM) loads to restore consumed power \cite{7}. Therefore, the modelling of IMs is crucial also in the sense of fault-induced delayed voltage recovery as it relates to short-term voltage stability. In this study, the instability mechanism that is observed, is the lack of attraction towards the stable post-disturbance equilibrium of short-term dynamics \cite{7}. This means, voltage instability is caused due to the stalling of IMs after a short-circuit. For heavily loaded IMs and/or slowly cleared fault conditions, IMs cannot reaccelerate after the fault is cleared. The mechanical and electrical torque curves of the IM intersect, but at fault clearing the IM slip exceeds the unstable equilibrium. It should be noted that the time scale of short-term voltage stability is also the time scale of transient instability. In this respect, short-term voltage instability may cause the loss of synchronism of a generator (transient instability) following a too slow fault clearing time \cite{7}.

This investigation focuses on balanced grid faults (positive sequence) whereas the GGC also defines requirements considering unbalanced grid faults (negative sequence). Furthermore, this study neglects other emergency voltage stability controls, i.e., countermeasures, such as load shedding, capacitor switching or STATCOMs, in order to focus on the impact of PV systems on the voltage instability phenomenon.
II. LOAD MODELLING

Load dynamic response is a key mechanism of power system voltage stability [7]. The aggregated load model is based on [8], [9] and explained in the following sections.

A. Static portion

For the static portion the exponential load model is used [7]:

\[ P = P_0 \left( \frac{V}{V_0} \right)^\alpha \]
\[ Q = Q_0 \left( \frac{V}{V_0} \right)^\beta \]

(1)

where \( P \) and \( Q \) are the active and reactive power, respectively, consumed by the load at the bus voltage \( V \). \( P_0 \) and \( Q_0 \) are the active and reactive power, respectively, under the reference voltage \( V_0 \). \( \alpha \) and \( \beta \) depend on the type of load [10] and are divided into Europe and America, as shown in Table I.

B. Dynamic portion

In power system studies usually aggregate IM models are assumed [7]. Therefore, the dynamic portion is represented as an aggregated third-order model of a single-cage IM. In this study, the IM model uses the rotor fluxes and the rotor motion dynamics as state variables. The rotor of the IM rotates at a speed \( \omega_r \neq \omega_s \) determined by the IM slip [7]:

\[ s = \frac{\omega_s - \omega_r}{\omega_s} \]

(2)

with the speed of the stator and rotor \( \omega_s \) and \( \omega_r \), respectively. The differential equation of the rotor motion dynamics is [7]:

\[ 2H \frac{d\omega_r}{dt} = T_e(V, \omega_r) - T_m(\omega_r) \]

(3)

with the inertia \( H \) and the electrical and mechanical torque \( T_e \) and \( T_m \), respectively. The mechanical torque is constant as this is more critical with respect to short-term voltage stability [7]:

\[ T_m = T_0 \]

(4)

with \( T_0 \) as the torque value at synchronous speed, i.e., \( \omega_r = 1 \) pu. The parameters of the IM represent a weighted aggregate of residential and industrial motors [9], as seen in Table I.

### Table I

<table>
<thead>
<tr>
<th>Description</th>
<th>Symbol</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Active power exponent</td>
<td>( \alpha )</td>
<td>0.62(^{\dagger})/0.72( ^{\dagger} )</td>
<td>[-]</td>
</tr>
<tr>
<td>Reactive power exponent</td>
<td>( \beta )</td>
<td>0.96(^{\dagger})/1.27( ^{\dagger} )</td>
<td>[-]</td>
</tr>
<tr>
<td>Static load power factor</td>
<td>( PF_{stat. \ load} )</td>
<td>0.95(_._______)</td>
<td>[-]</td>
</tr>
</tbody>
</table>

### Table II

<table>
<thead>
<tr>
<th>Description</th>
<th>Symbol</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Renewable energy generator/converter</td>
<td>Lvplsw</td>
<td>1</td>
<td>[-]</td>
</tr>
<tr>
<td>Enable or disable low voltage power logic</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum rate-of-change of active current</td>
<td>rprwr</td>
<td>2</td>
<td>[pu/s]</td>
</tr>
<tr>
<td>LVPL zero crossing</td>
<td>Zerox</td>
<td>0.3</td>
<td>[pu]</td>
</tr>
<tr>
<td>LVPL breakpoint</td>
<td>Brkpt</td>
<td>0.6</td>
<td>[pu]</td>
</tr>
<tr>
<td>Renewable energy electrical control</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum apparent current</td>
<td>I_max</td>
<td>1</td>
<td>[pu]</td>
</tr>
<tr>
<td>Reactive current injection gain</td>
<td>K_qv</td>
<td>2</td>
<td>[pu/pu]</td>
</tr>
<tr>
<td>Low voltage condition trigger voltage</td>
<td>V_dip</td>
<td>0.9</td>
<td>[pu]</td>
</tr>
<tr>
<td>Undervoltage deadband for reactive current</td>
<td>d_d2</td>
<td>0</td>
<td>[pu]</td>
</tr>
</tbody>
</table>

\(^{\dagger}\) Europe.  
\(^{\dagger}\) America.
referred to the terminal of the inverter. The characteristic of the additional reactive current is shown in Fig. 1 and can be calculated as:

$$\Delta I_Q = k \cdot \Delta V$$  \hspace{1cm} (7)

with the static gain $k$, also referred to as $k$-factor, and the voltage deviation $\Delta V$ determined from the prefault condition. The limit of the reactive current is defined as:

$$I_{Q, \text{max}} = I_{\text{max}}$$  \hspace{1cm} (8)

The active current can be reduced according to the reactive current injection considering (5). The voltage for the additional reactive current injection is measured at the terminal of the inverter. The dynamic reactive power support can also be requested at the Point of Common Coupling (PCC), therefore, inverter. The dynamic reactive power support can also be requested at the Point of Common Coupling (PCC), therefore, the gain $k$ in (7) needs to be aligned according to [5]. The step response of the reactive current contribution $\Delta I_Q$ should satisfy the following conditions at the terminals of the inverter: 1) response time $\leq 30\text{ ms}$; and 2) settling time $\leq 60\text{ ms}$. Regarding short-term voltage stability, the PV system control should act fast enough before the motors decelerate beyond the post-control unstable equilibrium point [7]. Furthermore, no deadband for the reactive current injection is required, instead, a voltage dip detection function is defined.

In order to implement this control mode, changes need to be made in the WECC generic PV system model in [11], i.e.: 1) a new control block was added to allow dynamic reactive power support without deadband; and 2) the parameter $V_{\text{ref0}}$ is initialized by the power flow solution as it should represent the prefault condition. The modifications are shown in Fig. 2.

$$\Delta I_Q = k \cdot \Delta V$$

$$\Delta I_Q \text{ [pu]}$$

$$\Delta V \text{ [pu]}$$

$2 \leq k \leq 6$

 capacitive

$k = 2$ (default)

$$\Delta V = V_{\text{fault}} - V_{\text{prefault}}$$

Fig. 1. Additional reactive current for dynamic voltage support [5].

D. Control Mode 2 (CM2)

Control Mode 2 (CM2) is based on [4]. The reactive current is limited as:

$$I_{Q, \text{max}} = I_{\text{max}} \cdot \frac{1}{\sqrt{2}}$$  \hspace{1cm} (9)

and results from an optimization problem for the maximization of the voltage through the active and reactive current injection of the PV system [4].

E. Control Mode 3 (CM3)

Control Mode 3 (CM3) is based on [1] and the objective is to adjust the active and reactive current according to the network impedance angle at the PCC in order to achieve an optimal voltage support at this bus. Therefore, additional measurements are required in order to determine the grid impedance angle on-line. The grid impedance at the PCC can be described as:

$$Z_{\text{PCC}} = |Z_{\text{PCC}}| \cdot \angle \Psi_{\text{PCC}}$$  \hspace{1cm} (10)

with the grid impedance angle $\Psi_{\text{PCC}}$. The optimal ratio of the active and reactive current according to the grid impedance angle can be defined as:

$$\Delta I_p = k \cdot \Delta V \cdot \cos(\Psi_{\text{PCC}})$$

$$\Delta I_Q = k \cdot \Delta V \cdot \sin(\Psi_{\text{PCC}})$$  \hspace{1cm} (11) \hspace{1cm} (12)

Considering the trigonometric angle relation $\tan(\Psi_{\text{PCC}}) = \sin(\Psi_{\text{PCC}})/\cos(\Psi_{\text{PCC}})$, the max. reactive current can be obtained as:

$$I_{Q, \text{max}} = I_{\text{max}} \cdot \frac{\tan(\Psi_{\text{PCC}})}{\sqrt{\tan^2(\Psi_{\text{PCC}}) + 1}}$$  \hspace{1cm} (13)

In this investigation, the grid impedance angle at the PCC is $\Psi_{\text{PCC}} = 82^\circ$, which is typical for sub-transmission networks. This leads to the max. reactive current of the inverter:

$$I_{Q, \text{max}} \approx I_{\text{max}} \cdot 0.99$$  \hspace{1cm} (14)

Due to the high grid impedance angle at the PCC, the limitation of the reactive current is marginal and therefore, almost equal to the GGC requirements, as it can be seen in (8). However, CM3 is more effective for smaller grid impedance angles, e.g., medium- or low-voltage connected PV systems.

IV. TEST SYSTEM

In order to study the mechanism of short-term voltage stability, a test system, as shown in Fig. 3, is considered. The extra-high-voltage network is represented by a voltage source and the dynamics of the generators are neglected in order to concentrate on the short-term voltage stability phenomenon. The large-scale PV system is connected to bus 3 and no plant-level reactive power compensation is active.

The test system parameters are mainly based on [13]. The parameters for the collector system equivalent are taken from [14] and represent a large-scale PV plant of a nearly similar size. It should be noted that the $X/R$ ratio of the collector system equivalent in [14] is relatively high. Usually this value is less than two. The test system parameters can be found in Tables III and IV.
Fig. 3. One-load infinite-bus system. The aggregated load consists of a static and dynamic portion that is represented by the exponential and the induction motor load, respectively. The load is compensated with a shunt capacitor that is connected to bus 3. The large-scale PhotoVoltaic (PV) plant is connected via an interconnection transmission line to bus 3, which is also referred to as Point of Common Coupling (PCC).

V. CASE STUDIES

Short-term voltage stability is investigated for several case studies, as listed in Table V. A three-phase short-circuit in the extra-high-voltage grid is applied by setting the voltage of bus 1 to 0.5 pu for 0.35 s. According to the FRT requirements of the GGC, the PV system needs to stay connected during this short-circuit and ride-through the fault. The aggregated load demand is 200 MW and the PV system generation is 0 pu for all case studies. To achieve a voltage of 1.0 pu at bus 3 in normal operation, the load is compensated with a shunt that is adjusted for each case study. Moreover, the measurement and control actions of the PV system are carried out at the PCC.

The results are evaluated based on numerical time-domain simulations performed with DlgSILENT PowerFactory [15]. The integration time step of the RMS simulation is 0.01 s. Additionally, the stability boundary is determined for all case studies and control modes in terms of the calculation of the Critical Clearing Time (CCT) of the fault to avoid stalling of the IM load.

Please note that the consumer-oriented sign convention has been used in this publication, i.e., consumed active power as well as inductive reactive power are positive and generated active power and capacitive reactive power are negative.

A. Case study (A)

Case study (A) describes the European scenario with the corresponding load ratio and load exponents, as seen in Table V. The PV system operates at unity power factor. The results are presented in Fig. 4. For all control modes the voltage recovers within less than 1 s. No short-term voltage instability is observed. The aggregated IM load does not stall. From the analysis of the different control modes, CM0 is the most severe one as the PV system does not support the voltage with additional reactive power. The control modes CM1 and CM3 are very effective in terms of voltage support and recovery, whereas CM2 is less effective than CM1 or CM3.

B. Case study (B)

Case study (B) is the same as (A) with the difference that the PV system is operated with a leading power factor in order to compensate the load. This means the PV system already provides capacitive reactive power in normal operation. The results are depicted in Fig. 5. From the voltage evolution it is clear that no short-term voltage instability is present. Similar to case study (A), the control modes CM1 and CM3 are very effective, whereas CM0 is the most severe one with respect to voltage support and recovery. Moreover, it should be noted that CM3 shows a slightly better performance than CM1.

C. Case study (C)

Case study (C) represents the American scenario with a high portion of IM loads, as seen in Table V. The results are shown in Fig. 6. In this case, short-term voltage instability occurs. For CM0 the aggregated IM load stalls after the fault is cleared, as presented in Fig. 7, because the IM slip exceeds the unstable equilibrium. Only with the injection of capacitive

<table>
<thead>
<tr>
<th>Description</th>
<th>Case study (A)</th>
<th>Case study (B)</th>
<th>Case study (C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Collector system equivalent</td>
<td>(30/70)</td>
<td>(30/70)</td>
<td>(70/30)</td>
</tr>
<tr>
<td>Interconnection transmission line</td>
<td>(0.62/0.96)</td>
<td>(0.62/0.96)</td>
<td>(0.72/1.27)</td>
</tr>
<tr>
<td>Transmission line</td>
<td></td>
<td>0.9_cap</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>0.6</td>
<td>1.4</td>
</tr>
<tr>
<td></td>
<td>1.1</td>
<td>0.6</td>
<td>America.</td>
</tr>
<tr>
<td></td>
<td>Europe.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base value: $S_{base}$ = 100 MVA.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
reactive current, i.e., CM1, CM2 or CM3, short-term voltage instability can be avoided. Similar to the case studies (A) and (B), the best performance can be achieved with the control modes CM1 and CM3, whereas CM2 is less effective than the other schemes in terms of voltage support and recovery.

D. Stability boundary

In order to determine the stability boundary for the different control modes, the CCT of the fault is calculated to avoid stalling of the IM load, according to case study (A) to (C), as shown in Table VI. The results indicate, the lowest stability margin is reached for CM0. On the other hand, the highest stability margin is achieved for CM3. In general, it can be said that any type of dynamic reactive power support, i.e., CM1, CM2 or CM3, considerably improves the stability boundary, in terms of the CCT of the fault.

<table>
<thead>
<tr>
<th>Case study</th>
<th>CM0 [s]</th>
<th>CM1 [s]</th>
<th>CM2 [s]</th>
<th>CM3 [s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>(A)</td>
<td>0.51</td>
<td>0.84</td>
<td>0.87</td>
<td>0.89</td>
</tr>
<tr>
<td>(B)</td>
<td>0.59</td>
<td>0.84</td>
<td>0.77</td>
<td>0.88</td>
</tr>
<tr>
<td>(C)</td>
<td>0.24</td>
<td>0.45</td>
<td>0.44</td>
<td>0.47</td>
</tr>
</tbody>
</table>

VI. CONCLUSIONS

The investigation has shown that FRT and dynamic reactive power support of PV systems help to avoid short-term voltage instability. The focus of this paper is the comparison and evaluation of the newly proposed GGC requirements for the high-voltage network with other promising control schemes in terms of FRT and dynamic reactive power support.

For the investigation, a generic PV system model defined by the WECC is utilized. Thereby, a realistic parameter set, determined in consultation with a manufacturer, is used. Furthermore, improvements of the WECC generic PV system model are stated.

The results indicate that the GGC requirements are effective in terms of FRT and dynamic reactive power support as well as the resulting voltage support and recovery. Only the adjusted control mode shows a slightly better performance than the GGC and is even more effective for smaller grid impedance angles, e.g., medium- or low-voltage connected PV systems. However, as this control mode needs on-line information about the grid impedance angle in order to adjust the optimal active and reactive current ratio, and therefore, additional infrastructure for the measurements, it is also more expensive. Thus, it can be concluded that the GGC requirements are reasonable from a technical and economical point of view.
The short-term voltage stability phenomenon might not be a system-wide issue in Europe/Germany, due to a smaller portion of directly-coupled IMs and undervoltage protection schemes in the power system that disconnect loads with significant low bus voltages. However, the investigation clearly demonstrates the improvement of the power system dynamic performance in terms of voltage support and recovery as well as the potential of PV systems to prevent the power system from a wide-spread blackout also with respect to transient stability.

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