PRACTISE-ORIENTED CONSIDERATION OF THE DYNAMIC FAST FAULT CURRENT OF POWER PARK MODULES IN GRID PROTECTION ANALYSIS

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ABSTRACT

Protection design in distribution grids is usually undertaken by simple to handle practice-oriented steady state calculation-methods. For the calculation of the minimal short circuit current models and methods are described in IEC 60909 [1]. In the revised version from 2016 constant current sources for modeling of reactive current infeed of converter-based generators due to mandatory grid support in Germany are considered, though the infeed is voltage dependent. Moreover, the dynamic settling process of the reactive current infeed can affect the functionality of the protection, which is not taken into account in steady state calculations.

This paper outlines a possibility to estimate the influence of these new dynamic effects on grid protection behavior in steady state calculation methods. Different types of Decentralized Generation (DG) units as well as other influences, e.g. grid topologies, distribution of DG or protection concepts are taken into account.

We will show that suitable steady state calculations are sufficient for practical protection analysis. The risk of undesirable reactions of the grid protection can be minimized by the use of the derived general recommendations.

INTRODUCTION

The increase of Decentralized Generation (DG) in low and medium voltage grids and its participation in fault situation system services (e.g. dynamic grid support by fast fault reactive currents I_q) lead to new challenges in grid protection analysis. However, easy to use calculation methods with models that can be parametrized by information provided by the plant manufacturer and operator during the standardized connection agreement are needed for practical distribution system planning and parameterization purposes. Therefore, standardized and well established methods for short circuit current determination are defined in IEC 60909 [1]. The requirements for DG in fault situations defined by the network operator and the realization by the manufacturer within this defined framework are not entirely considered in these calculation methods. This procedure may therefore lead to results, which are not precise enough under specific conditions for protection system design and parametrization. For example $I_q(U)$-dependency of DG with full size converters is neglected.

PROTECTION DESIGN IN PRACTICE

Present protection concept in medium voltage grids

In German Medium Voltage (MV) distribution grids the definite-time overcurrent protection (OCP) is most widely used. It is usually designed as selective main protection (MP) and backup protection (BP) as shown in Figure 1.

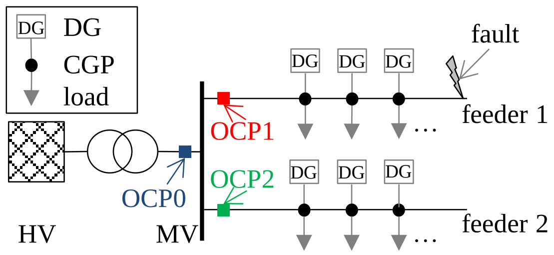

Figure 1: Illustrative MV distribution Grid containing two feeders with main and backup protection

The fault case in feeder 1 in the image above is recognized by OCP1 as MP and by OCP0 as BP. OCP2 forms the main protection for feeder 2 and should not be stimulated in the shown fault case.

In grids without DG and resonant-earthed-neutral system, a correct protection behavior is achievable by regarding a two phased fault at the end of the feeder, resulting in the minimum fault current. The complete short circuit current hast its origin in the overlaying grid (HV). OCP0 and OCP1 are recognizing the same current value. Here OCP2 is not stimulated.

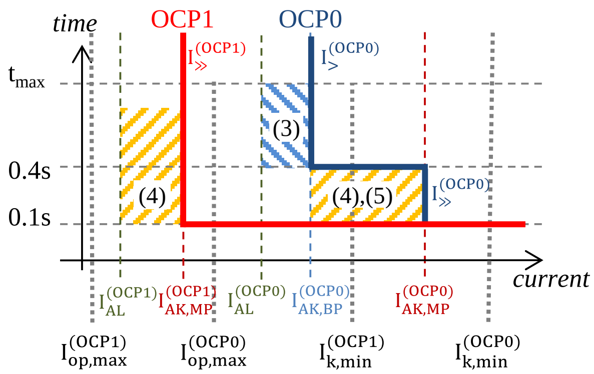

Figure 2: Simplified protection scaling of OCP0 and OCP1 from Figure 1, using equation (3) to (5)

A graduation between MP and BP can be configured

using a longer delay time for OCP0. Basically in relay charts an overlap is prevented as shown in Figure 2.
Present guidelines give recommendations for proper delay times [2]. 100ms are recommended for the quick time level. Additionally a relay separation of about 300ms should be used.

Calculation of the corresponding values

As mentioned above, steady state calculation methods for the minimal short circuit current are used in practice, corresponding to standard IEC 60909. Normally dynamic simulations are only applied in specific cases due to their complex parametrization and long calculation times, particularly for large systems. In simplified approaches uncertainties are covered to certain extend using adjustment factors, defined in the standard. However, the standard only aims at sufficiently correct short circuit current values at the fault location. Therefore a so called "pickup reliability factor" (f_{AK}) is used in protection parametrization considering all additional uncertainties. The maximum setting of the protection is given as:

(1) $$I_{AK} = \frac{I_{k,min}}{f_{AK}}$$

For the MP the usage of a factor of $f_{AK,MP} = 1.5$ and for the BP of $f_{AK,BP} = 1.3$ is a common practice [2].
For the lower parametrization limit a so called "pickup security factor" (f_{AL}) is used to consider the equivalent calculation of I_{AL} regarding the maximum operation current $I_{op,max}$:

(2) $$I_{AL} = I_{op,max} \cdot f_{AL}$$

Thus, the pickup values for main ($I_{>>}$) and backup ($I_{>}$) protection is limited to:

(3) $$I_{AL} \leq I_{>} \leq I_{AK,BP}$$

(4) $$I_{AL} \leq I_{\gg} \leq I_{AK,MP}$$

(5) $$I_{>} \leq I_{\gg}$$

In consequence the shown protection scaling shown in Figure 2 ensures a selective protective behavior. Here a fault clearance proceeds after 0.4s. Provided the MP behaves correctly, the BP's protective pickup will fall back, if the relevant current value falls below the device specific drop-off value (I_{do}), mostly around 90% of the configured $I_{>}$ and $I_{>>}$.

CHALLENGES OF SPECIFIC DG INFEED IN FAULT CASES

In Germany DG are required to remain connected during a grid fault according to the standardized connection agreement, the so called low voltage ride through (LVRT) [3].
The current infeed depends on:

- the voltage level
- specifications of the network operator
- DG type and DG manufacturer

In MV grids a so called dynamic grid support by fast reactive fault currents is additionally required for DG plants, e.g. in MV directives [4] [5]. Here, DGs include power station units with full sized inverters (PF) and double feet injection generators (DFIG).

Requirements on a dynamic grid support by fast fault currents

Requirements on the reactive current infeed of DG

The specific current infeed of the DG in a fault situation depends on the voltage drop at the grid connection point (GCP). Depending on the voltage drop level the DG should inject an additional reactive current according to the characteristic line shown in Figure 3. Here the K-Factor describes the slope of the line, which is chosen by the grid operator between 2 and 10.

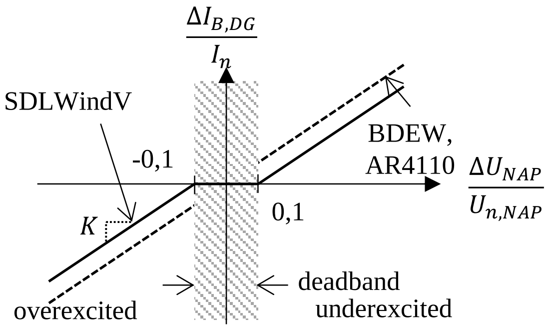

Figure 3: Required additional steady state DG reactive current injection for positive sequence voltage drops at the GCP

There is no specification for the active current injection of the DG. But for PF the current amount is limited to a value close above the rated current due to the PF valve rating. This can be realized by the computing based injection control. For DFIG an additional short current input driven by the rotating machine to be expected. For this reason a current up to $6I_n$ during the dynamic settling process is possible [6]. The resulting dynamic behavior for faults with high voltage drop at the GCP is shown in Figure 4.

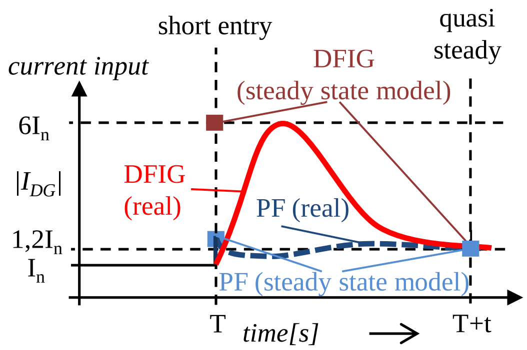

Figure 4: real DG-type dependent course of the current injection at the GCP after voltage drops and models

Regarding the standardized requirements the dynamic settling should happen within 60ms [5]. The behavior is verified in the course of the plant and unit certification [7].

Measured DG behavior during dynamic grid support

To investigate the actual behavior of commercially available PV inverters, measurements haven been conducted in the testing center of the Institute for High Voltage Engineering of the RWTH Aachen. The behavior of four inverters of different manufactures with powers between 9kWp and 30kWp is analyzed regarding their active and reactive current injection during different symmetric and asymmetric grid faults [8]. The results show various diverse behavior regarding the infeed during dynamic grid support. While the reactive current infeed copes with requirements, the active current infeed varies between zero and the maximum active current allowed by the total current limits in the steady fault state.

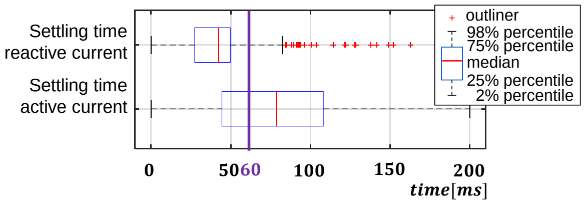

Figure 5: Measured settling times of PV inverters with dynamic grid support for various symmetric and asymmetric faults

Furthermore the settling times of the reactive and active current after the fault occurrence are investigated (Figure 5). The settling times of the reactive current appear to be lower than the required 60ms for most fault cases. In contrast, the settling times of the active currents, which are not restricted in the current regulations, reach values up to 200ms. This can lead to problems, when low protection delays are necessary, since the infeed-currents within the transition time are hardly predictable. Therefore future requirements should state restrictions for both the reactive and active current settling times.

Impact on the network protection

The described DG behavior at the respective GCP has a corresponding impact on the network protection regarding Figure 1. Three aspects are relevant:

a) The reactive and active power infeed of the DGs downstream of a regarded protection devices aggregates at its installation point. Therefore the contribution of upstream network to the short circuit current can be temporarily reduced (blinding).
b) DGs in parallel feeders inject an additional short circuit current amount, which is also registered by the main protection at this feeder (OCP2 in Figure 1). This effect can lead to erroneous activation of this device (sympathetic tripping).
c) The mutual impact of the DG can extend the settling process significantly. This can lead to selectivity problems of the backup protection.

As described the network protection is parametrized for a tripping in 100ms after the fault inception. As a result, there is an overlap between the DG-settling process and protection tripping.

In the following example the settling process of all DG in Figure 1 is simulated after a three-phase fault at the end of feeder 1. Figure 6 shows the resulting phase current, which is relevant for the OPC0 pickup criteria.

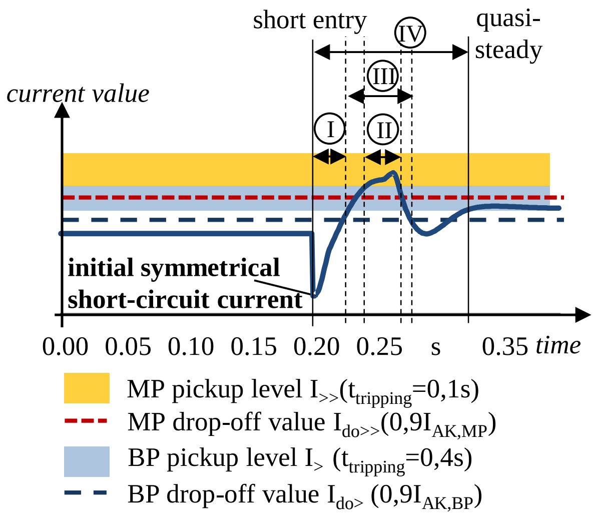

Figure 6: Illustrative current course at OCP0 after fault occurrence

In general, OPC0 should ensure the backup protection within a tripping time after 0.4s in the case of OCP1 fails. However, following issues are identified:

I. A delayed pickup due to a reduced initial short circuit current at the protection device
II. A hyperfunction due to a temporary leap into the quick time level. The relapse proceeds only after the shortfall below $I_{do,>>}$
III. Only a brief stay in the correct backup level, then temporary shortfall below $I_{>}$. due to the mutual influence of the DG
IV. Delayed permanent protective pickup and tripping in the backup level (pickup swing)

New requirements for steady state calculation methods

The analysis of Figure 6 illustrates, that a simplified steady state calculation is not sufficient anymore for all protection designs in MV grids, even when the revised IEC 60909 is used [1]. A Rather at least two conditions have to be taken into account, as Figure 7 illustrates:

(A) Short circuit failure entry
(B) Quasi steady condition with settled DG current injection

(A) can be estimated either by means of the revised standard calculation or it can be determined by so-called exact calculation methods. (B) therefore has to be calculated by implemented methods [9]. The modelled DG-behavior is illustrated in Figure 4. Not yet considered is the range in between, where the described settling effects occur.

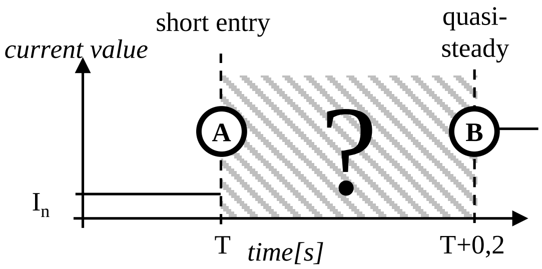

Figure 7: Possible steady state calculation points

MODELLING AND SIMULATION OF THE SETTLING PROCESS

Network and DG models

In order to evaluate the effect of the settling process on protection tripping numerous dynamic simulations have been undertaken, applying present approved models for network components and DGs (Figure 4). Other dynamic effects are neglected.
The regarded 20-kV-grid has the topology shown in Figure 1. Depending on the case at issue (a) to (c) specific worst-case DG-scenarios are considered a priori. Therefore as described above exclusively DFIGs are used.

Measurement value evaluation of protection devices

In the simulations root mean squares (RMS) of the phase currents are determined. There is no detailed modelling used for the measurement value the evaluation of OCPs. Rather it is assumed that common protective computing algorithm leads to a smooth measurement value [10].

Simulation of the considered situations

In general, the issued fault cases are two and three phase short circuits in resonant-earthed networks and those with isolated neutral points at the end of feeder 1 (Figure 1), which are reviewed in this example. Additional single-phased shorts are relevant at other neutral point treatment. But further simulations have shown similar results in these cases as in the shown ones. By means of sensitivity analyses the influence of the DG-behavior is identified in the described cases at issue (a) to (c):

a) "Blinding" of the main protection
Relevant for consideration is an assumed high installed power of DFIGs in feeder 1 in Figure 1. Therefore the inertial short current leads to a reduced current at the protection device and a delayed pickup (I) is thinkable.

b) "Sympathetic Tripping" of the parallel MP
Relevant for consideration is an assumed high installed power of DFIGs in feeder 2 according to Figure 1. Therefore the initial short current at OPC2 increases and a hyperfunction of this device is thinkable, either dynamic according to issue II or even steady state.

c) Selectivity problems of the backup protection
Relevant for consideration is an assumed high installed power of DFIGs in feeder 1 and 2 according to Figure 1. Therefore a malfunction of OPC0 is thinkable, again both due to dynamic issues III and IV as well as steady state.

DETECTED PROTECTIVE MALFUNCTIONS

Selected results of the described dynamic simulations are shown in Figure 8.

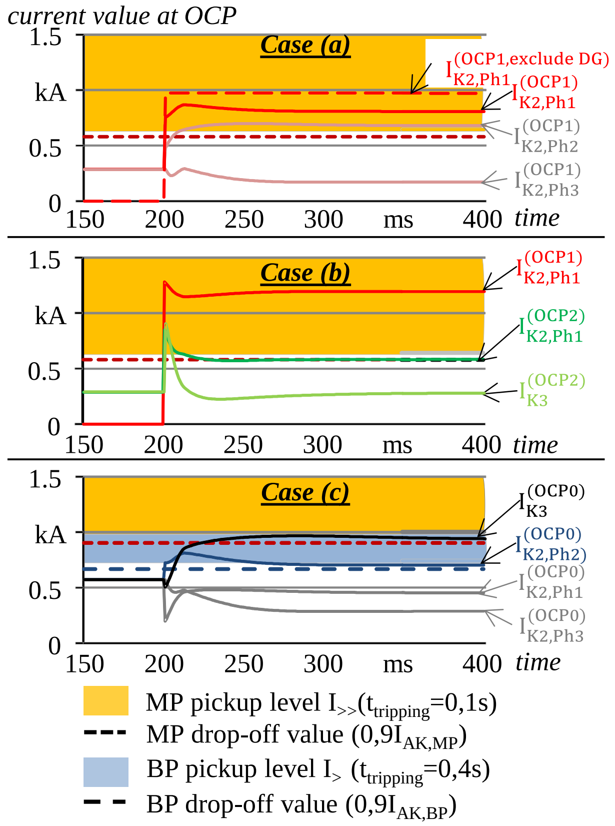

Figure 8: Dynamic Simulation of the current course at the PCP in (a)-(c)

Based on these results we come to the following conclusions.

a) "Blinding" of the MP

In case (a) the maximal phase current measured at OCP1 ($I_{K2,Ph1}^{(OCP1)}$) can be seen to directly reach the quick time level. The currents in the other phases are also influenced significantly. Although the current is reduced slightly the protection stimulus remains. The whole time the correct tripping after 100ms is expected. Therefore a blinding due to dynamic effects does not occur.

b) "Sympathetic Tripping" of the parallel MP

In case (b) the corresponding measured current at OCP1 leads to an undelayed pickup of this protection device. However OCP2 is stimulated in the fast time stage simultaneous. Whereas the current over OCP1 remains in the same level, the value at OCP2 falls back below the pickup level, but in a two-phased fault only close to the range of the drop-off value. Therefore there is a threat for unselective tripping of OPC2 after 100ms.

c) Selectivity problems of the BP

In a two phase fault tripping on I>, OCP2 is delayed. The phase current is reduced after a view milliseconds but remains higher than the drop-off value $I_{>,do}$.
Regarding real OCP-algorithms it is not certain that the necessary pickup will take place. But with the aim of the described steady state calculation methods this evaluation can be reached sufficient.
In addition, with regards the three-phase fault current there is a potential unselective pickup in the quick time level. However this problem can be avoided with the use of pickup interlock parametrization because of the pickup in quick time level of OCP1

DERIVED RULES FOR THE EVALUATION AND PREVENTION OF PROTECTIVE FUNCTIONS USING STEADY STATE APPROACHES

The protection parametrization can be approximately evaluated by the calculation of the conditions in the fault inception (A) and in the settled state (B). The example shown dynamic simulations for (a) to (c) shown in Figure 8 permit an evaluation of the protective issues I. to IV. pictured in Figure 6.

I. It is identified a 20ms pickup delay by the use of the recommended relay separation of 300ms no protective issue are to be expected.
II. A hyperfunction seems to be possible. All error types should be considered. Additional the mentioned pickup security factor should be maintained reducing this risk.
III. A fall back out of the pickup level while a fault case might be possible. Therefore considering the drop-off value of the OCP is necessary by calculating (B), if a pickup is identified in (A) by the use of the in Figure 4 shown model-assumptions.
IV. A pickup swing has not been identified in the regarded grids

SUMMARY

In distribution grids with a high amount of installed DG remaining in operation during a fault case and participating at a dynamic grid support by fast fault currents, used steady state calculation methods have to be reconsidered. Besides the determined inertial short circuit current the state with settled DG-currents have to be taken into account.
Furthermore there are additional dynamic effects in high DFIG-penetrated grids, which could influence the protective behavior. The real settling times have been analyzed in laboratory. The resulting durations lay in between 60 and 200ms for PF. For DFIGS similar ranges are expected.
The influences of the DG-settling on the grid protection have been investigated in dynamic simulations by means of wort-case-assumptions for issue (a) to (c). For a priori identified resulting dynamical challenge I. to IV. rules have been derived for the protection design. The risk of unintended behavior of the grid protection can be minimized by the use of these general assumptions. Additional guidelines for the parametrization of grid protection to avoid such problems have been given.
Consequently, a further use of steady state calculation methods is possible with consideration of the fault inception (A) and the steady state after DG-settling.

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