REGIONALIZED AGGREGATION OF DISTRIBUTED ENERGY RESOURCES AND DISTRIBUTION NETWORKS FOR LARGE-SCALE DYNAMIC SIMULATIONS

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ABSTRACT

The increase of distributed energy resources (DER) and the decreasing conventional centralized power generation result in transmission grid behavior that is strongly influenced by distribution systems. An approach to model their influence while taking the regional differences of the infeed and load distribution as well as the regional topology into account is therefore necessary. However, a detailed large-scale model containing all voltage levels is impractical due to the enormous amount of models and nodes. This paper describes a method to create aggregated regionalized distribution networks for dynamic simulations in the transmission grid. The validity of the method is tested and a comparison of a test system with and without distribution networks is presented to show the influence of the modeling method.

INTRODUCTION

The transition from conventional electrical energy production towards more decentralized production such as wind power, PV, biomass as well as combined heat and power infeeds in European electricity grids leads to a shift from centralized to decentralized energy resources (DER). The voltage and frequency control provided by DER differs vastly from conventional power plants and thus, influences the dynamic behavior for example during short circuit events [1]. Furthermore, the behavior of DER varies according to the applicable grid codes, which depend on the commissioning year, nominal power and voltage level of each infeed. Hence, these factors must be considered to model low voltage (LV) and medium voltage (MV) distribution system behavior in a high voltage (HV) grid accurately. However, modeling each distribution network (DN) down to the low voltage level in detail leads to enormous network models and is therefore impractical for large-scale grid simulations. In [2] a method to aggregate DER to an in depth model as a grey-box is proposed. However, this method requires detailed information about the DN. [3] uses a vector fitted variable order transfer function to simulate the behavior of a DN without considering nonlinear behavior. An approach to create a generic model is described in [4], which reduces a DN to a single bus model in order to simulate faults in the DN. The focus of this paper is set on the behavior of DNs during faults in the transmission grid. An analysis of the impact on transmission grids was not conducted in the aforementioned studies.

This paper describes a procedure to model detailed regionally specific DNs in an aggregated form using generic data, and still regarding their influence and behavior. By determining equivalent impedances and parameterizing DER models according to relevant grid-codes, the method minimizes the error between a detailed and aggregated grid model for dynamic and steady state calculations. The method is tested on a modified IEEE 14-bus test system and is compared to a conventional test system.

METHODICAL APPROACH

The modeling process, as shown in Figure 1, uses regional demand and DER statistics to generate detailed distribution system models, which then are aggregated.

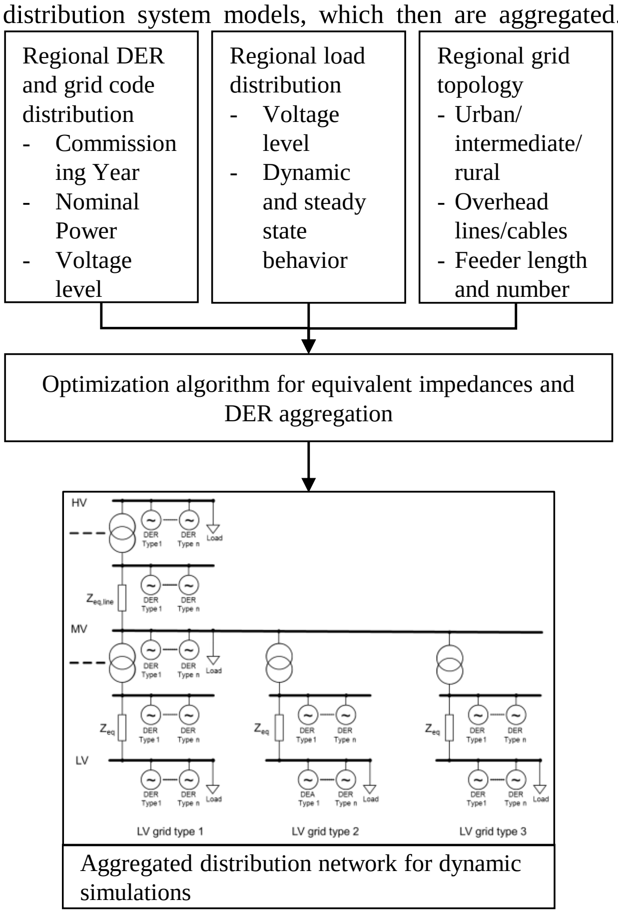

Figure 1: Overview of the proposed methodology

The share of each DER type is modeled with respect to the applicable grid codes and the regional DER data. The impact of the regional load distribution regarding voltage levels and (static & dynamic) load behavior is also taken into consideration.
Additionally, the topology of LV and MV grids is factored in by selecting different detailed reference grids based on the urban, intermediate or rural topology of a region. Thus, detailed regionally representative DNs are modeled, which form the basis for the further aggregation.
To integrate the DNs in large-scale transmission system simulations, they are aggregated to a set of equivalent impedances [1]. The equivalent network impedances for each DN level are calculated using an optimization algorithm, which minimizes the error of the dynamic active and reactive power behavior between the detailed and aggregated grid during a short voltage drop.

DER Model

The DER model encompasses the stationary as well as the fault behavior of a converter based infeed and is used to represent photovoltaic and wind generation. In the following, some examples based on German grid codes are defined. The overall possible parameterizations are not limited to these examples and can be adapted to other grid codes.

Stationary Behavior

The reactive power infeed of DER in stationary conditions varies for different grid codes. The reactive power control can be based on a constant power factor (PF), on the power factor as a function *PF(P)* of the momentary active power or on a *Q(V)*-characteristic. The applicable behavior is defined in the grid codes.

Dynamic Behavior

Grid codes, such as the German codes VDE-AR-N 4110 and VDE-AR-N 4120, require the DER to stabilize the grid during a voltage drop by injecting additional reactive current outside of a deadband zone. This behavior is called fault-ride-through (FRT). The magnitude of the additional current $I_{Q,fault}$ is calculated by (1) with the momentary voltage during the fault V_t, the voltage before the fault V_0 and the droop k. The maximum reactive current is limited by the nominal apparent power of the DER. If the sum of the reactive and active current exceeds this threshold, the active current and thus the active power is reduced.

$$I_{Q,fault} = (V_t - V_0)\, k \qquad (1)$$

Furthermore, the disconnection conditions for DER for each voltage level are modeled. Thus, the DER disconnect from the grid, if the voltage drops below a certain threshold or if the duration of the voltage drop exceeds a set time.

Regionalized Load Modeling

The load model is enhanced by using a ZIP-model with additional dynamic frequency and voltage behavior. The stationary behavior of the reactive and active power is defined by the constant parameters for the impedance *Z*, the current *I* and the power *P*. The dynamic behavior is modeled using transfer functions with variable gains and time constants for the active and reactive power. This allows taking differences of the load profiles of different regions as well as seasonal and time of day dependent influences into consideration. A more detailed analysis is described in [5].

Representative Distribution Networks

The LV-DNs used for the aggregation are based on representative grids from [6]. Overall, nine different representative LV-DNs are used. They are distinguished by three different topologies for rural, intermediate and urban regions. Three different grid structures are used for each topology. They are differentiated by the nominal apparent power of the MV/LV transformer, the number and length of feeders and the share of overhead lines and cables in the grid. Furthermore, four different grids from [1] are used to model the behavior of the MV-DN matching the representative grid structure of rural/intermediate and urban regions.

Distribution Network Aggregation

Based on the regional data, the distribution of the DER and load to the voltage levels and grid codes is determined. The detailed representative DNs are selected depending on the rural, intermediate or urban topology of the region. The aggregation is then performed in two steps. First, the equivalent DN for each detailed DN type is modeled. This is done by populating the reference LV-DN with i loads with $P_{load,det,i}$ and with i detailed DER for each DER type k with the active power $P_{DER,det,k,i}$. The different DER types are defined by the applicable grid codes and infeed types in the network. A schematic representation of the detailed LV-DN is depicted in Figure 2 on the left.

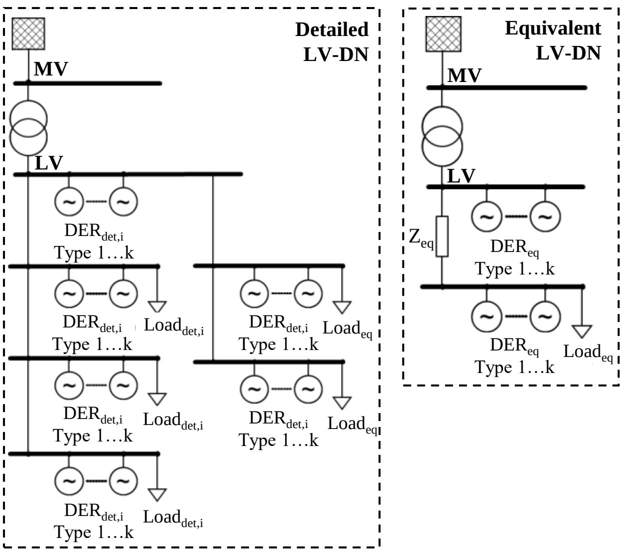

Figure 2: Schematic detailed and equivalent grid

The equivalent grid in Figure 2 on the right is created using (2) and (3), where the active power of the DER with the same type k is aggregated to $P_{DER,eq,k}$ and the active power of the load is aggregated to $P_{load,eq}$.

$$P_{DER,eq,k} = \sum_i P_{DER,det,k,i} \tag{2}$$

$$P_{load,eq} = \sum_i P_{load,det,i} \tag{3}$$

The detailed grid model is subsequently reduced to an equivalent resistance R_{eq} and reactance X_{eq} of the equivalent impedance Z_{eq}, which is then optimized with the DIgSILENT PowerFactory System Parameter Identification tool, such that the stationary and dynamic behavior of the detailed and aggregate grid are closely matched. This is done by applying a set voltage drop of 0.5 pu for 150 ms at the MV bus and minimizing the error in the dynamic active and reactive power flow at the transformer's MV side in the detailed and aggregate grids as shown in (4).

$$\min\left[\left(P_{det}-P_{eq}\right)^2+\left(Q_{det}-Q_{eq}\right)^2\right] \\ s.t. R_{eq}, X_{eq} > 0 \tag{4}$$

In the second step, the equivalent MV-DN is modeled. The optimization process for the MV-DN is then performed in a similar fashion as for the LV-DNs. The DER, loads and equivalent LV-DNs are integrated into the detailed MV grid according to the respective distributions. The DER and loads in the MV grid are aggregated as described in (2) and (3). The LV-DNs are aggregated with (5) for each type, where n is the number of LV-DNs of that type in the MV grid, P is the active power of the loads and DER and $S_{N,MV/LV}$ is the nominal apparent power of the MV/LV transformer.

$$\begin{aligned} P_{DER,LV,sum} &= n\, P_{DER,LV} \\ P_{load,LV,sum} &= n\, P_{load,LV} \\ S_{N,MV/LV,sum} &= n\, S_{N,MV/LV} \\ R_{eq,LV,sum} &= R_{eq,LV}/n \\ X_{eq,LV,sum} &= X_{eq,LV}/n \end{aligned} \tag{5}$$

The equivalent MV grid in Figure 3 is populated with the aggregated LV-DNs, loads and DER. A pi-equivalent model with $R_{eq,line}$, $X_{eq,line}$ and $C_{eq,line}$ is used for the for the equivalent grid impedance. The same optimization process as conducted for the LV-DNs is performed to calculate the equivalent MV impedance. The resulting equivalent MV grid is then installed into the given transmission grid at the HV level. Any DER and loads, which are located in the HV grid, according to the distributions, are implemented at the connection of the MV grid to the HV grid.

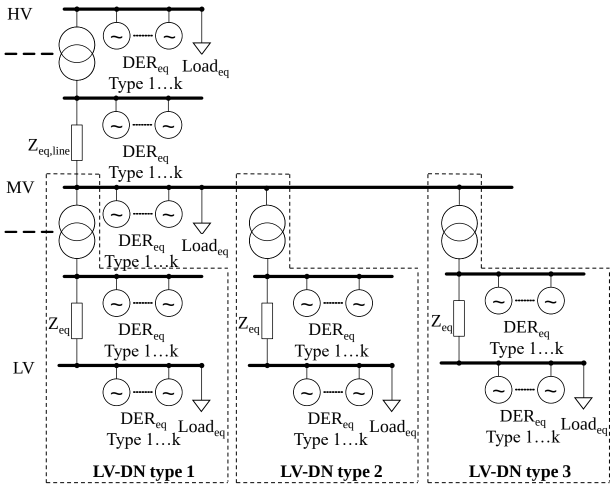

Figure 3: Schematic equivalent of an MV-DN with multiple aggregated LV-DN types

EXAMPLARY AGGREGATION

The described aggregation methodology can be applied to various transmission grids with an HV level. An example for such an aggregation is shown in the following section for the test system in Figure 4. Afterwards, the behavior of the test system with and without aggregated DNs is evaluated.

Test Grid

The aggregation is tested with a modified IEEE 14-bus system Figure 4 from [7]. It consists out of a 220 kV level (blue) with 171.3 MW total load and a 132 kV level (red) with 87.7 MW total load. In order to evaluate the influence of DER, all synchronous generators are deactivated and a total of 15 MW PV and 180 MW wind power is integrated in the 132 kV level. The DER are modeled as constant impedance infeeds connected at the HV level with a power factor 1. An external grid with a nominal voltage of 1.04 pu and an apparent short circuit power of 5 GVA is connected at Bus_0001 as a slack infeed.
An equivalent DN is modeled at the nodes given in Table 1. Different DER and load distributions are used for each topology representing regionally different parameterizations. PV infeeds are installed in the LV level, while the wind power DER are installed in the MV and HV level.

Table 1: Nodes with modeled DNs

Bus name	Topology	PV in MW	Wind in MW	Load in MW
Bus_0006	rural	0	100	11.2
Bus_0010	intermed.	10	40	9
Bus_0011	rural	0	20	3.5
Bus_0012	rural	5	20	6.1
Bus_0013	urban	0	0	13.5
Bus_0014	urban	0	0	14.9

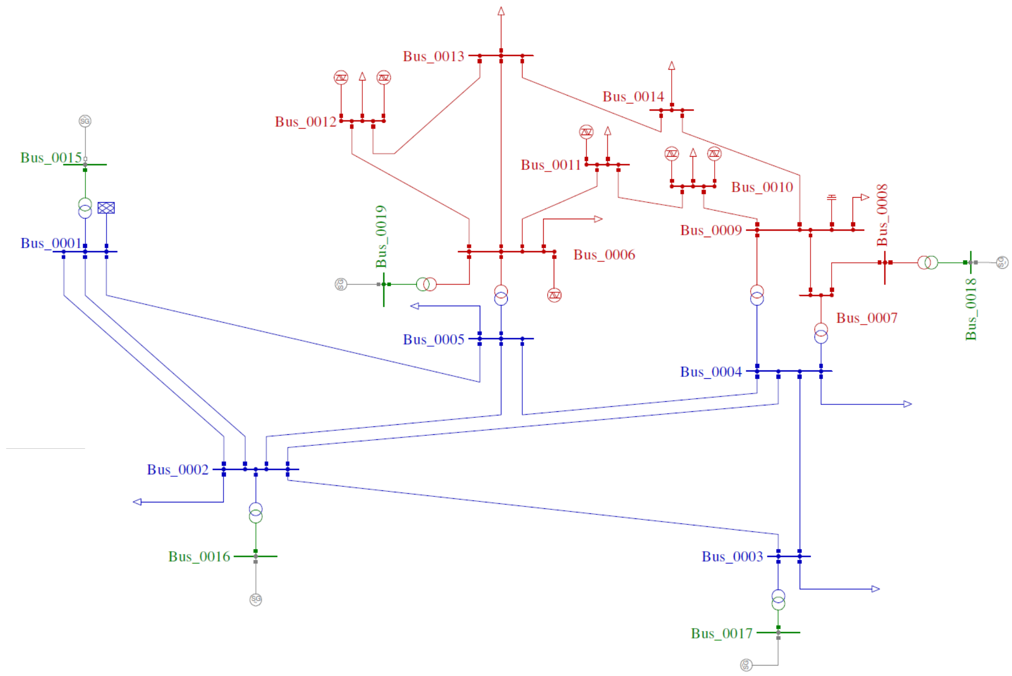

Figure 4: Modified IEEE 14-Bus test system

All DER are set to feed in at their nominal power. The stationary behavior of LV infeeds is defined by the a *PF(P)* control, which is set to 0.9 ind. at the nominal power. The reactive power of infeeds in the MV level are defined by the power factor function of P with 0.95 ind. at the nominal power. DER located directly on the MV side of the HV/MV transformers are set to a constant power factor of 0.975 cap. All infeeds in the HV level are controlled by a *Q(V)*-characteristic with a reference voltage of 1.03 pu and a maximum power factor of 0.95 ind. and cap. The selected FRT behavior depends on the voltage level of the DER. Infeeds in the LV level do not inject reactive current due to the fault-ride-through characteristic. The FRT behavior of infeeds in the MV and HV level is based on the German grid codes VDE-AR-N 4110 and VDE-AR-N 4120 with droop k set to 2.

In order to evaluate the result of the aggregation, a voltage drop of 0.5 pu at Bus_0012 for 150 ms at 0.1 s at the HV side of the transformer is simulated in the detailed as well as the aggregated grid. Figure 5 shows the voltage at the MV node at the HV/MV transformer and the active/reactive power flow over the transformer of the detailed and aggregated DN. The stationary voltage and power flow are identical, thus, the pi-equivalent model and the equivalent impedances are a valid method to represent the stationary behavior of the detailed grid. The dynamic behavior of the voltage and power flow of the aggregated grid shows no deviations from the behavior of the detailed grid. Therefore, the DER's FRT behavior is accurately aggregated while retaining the overall behavior of the detailed grid.

In conclusion, the aggregated DN is a valid method to simplify a detailed DN. The stationary operation before the voltage drop shows an active power flow from the MV to the HV level. The DN draws reactive power from the HV level due to the grid losses and inductive behavior of the loads and DER. The voltage drop leads to a reversal of the reactive power flow due to the fault-ride-through behavior of the DER. Thus, the voltage shows a slight increase after the initial voltage drop due to the additional reactive current. The active power infeed of the DER is reduced due to the limited infeed capabilities.

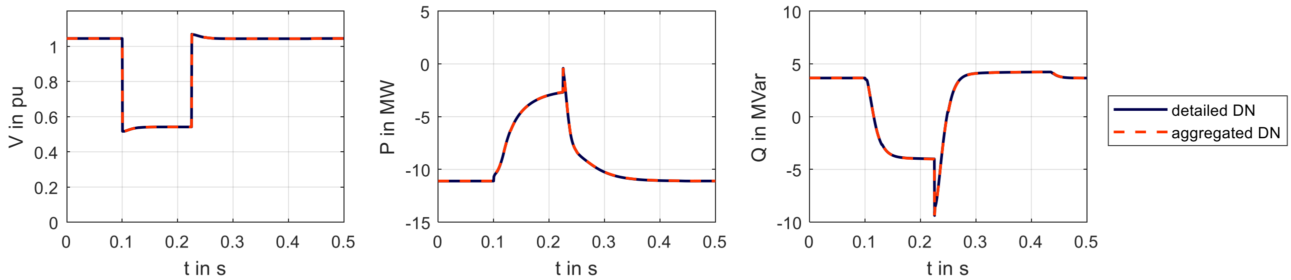

Figure 5: Optimization results for the detailed and aggregated DG at Bus_0012

Comparison

The stationary behavior of the reference grid without aggregated DNs differs from the model with DNs in several ways. The grid losses increase due to additional impedances, lines and transformers by 2.12 MW from 7.6 MW to 9.72 MW. Furthermore, the reactive power demand changes from 7.9 MVar to -7.88 MVar due to the mainly inductive behavior of the DNs. The reactive power drawn from the external grid is reduced by 7.4 MVar from 63.1 MVar to 55.7 MVar. This is due to the inductive DNs and the reactive power drawn by the DER compared to simplified constant impedance model of the DER used in the base grid, whereby reactive power infeed is neglected. Thus, modeling the DNs leads to considerable change in the reactive power flow of the system compared to the model without dynamic DER and aggregated DNs.

Figure 6 shows the stationary voltages for the 220 kV (left) and the 132 kV (right) nodes. The DNs lead to small increases in the voltages at the 220 kV level. The changes in the 132 kV level are more distinctive, which are mainly influenced by the reactive power control of the DER.

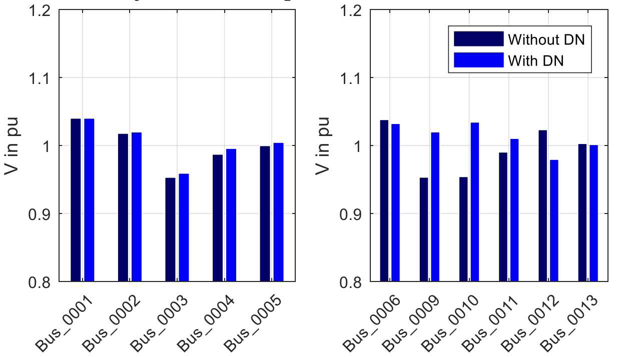

Figure 6: Stationary voltages for the 220 kV nodes (left) and the 132 kV nodes (left) with and without DNs

The dynamic behavior of the reference grid and the grid with DNs is compared by simulating a short circuit at Bus_0003 on the 220 kV level for 150 ms. The results are depicted in Figure 7. The voltage before the fault in the 220 kV level (left) is almost identical. However, the voltage drop after the short circuit is reduced by about 0.08 pu after the initial reaction. This is due to the additional reactive current supplied by the FRT behavior of the DER.

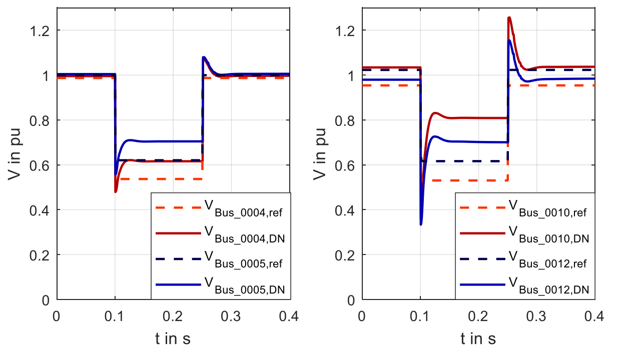

Figure 7: Dynamic behavior of two 220 kV nodes (left) and two 132 kV nodes (right) during a short circuit at Bus_0003

An even more drastic difference can be observed in the 132 kV level, where the voltage at Bus_0010 only drops to 0.80 pu instead of 0.53 pu. This is partly due to the higher initial voltage. The dynamic behavior at Bus_0012 shows, that the voltage during the fault is stabilized at 0.7 pu compared to 0.61 pu even though the initial voltage is lower than in the reference grid. Thus, the effect of the DER's FRT behavior can be seen as a decisive factor for voltage stabilization.

The reduced voltage drop during a short circuit event can prevent other DER from disconnecting from the grid due to low voltages. Thus, the stabilizing effect of the DER's FRT behavior allows a more precise analysis of the effects of short circuits in transmission grids. The effects of the dynamic loads must be further explored in future studies.

SUMMARY

The proposed aggregation method allows modeling multiple distribution networks in a transmission grid simulation without requiring a large number of individual controllers while retaining an almost identical stationary and dynamic behavior. The regional DER and load distributions and parameterizations as well as the regional topology can be taken in to consideration for aggregated models. The distribution networks have been shown to influence the stationary as well as the dynamic behavior of a transmission grid drastically. Thus, modeling the distribution networks and the consideration of the different parametrizations of DER in the different voltage levels is a vital contribution to increase the quality of simulations of transmission system with a high share of decentralized energy resources. A further increase in quality can be obtained by improving the representative LV and MV grids and thus, creating distribution networks closer to the actual regional structure. Furthermore, the influence of regionalized load parameters must be assessed in more detail.

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