# Avoiding Adverse Interactions between Transformer Tap Changer Control and Local Reactive Power Control of Distributed Generators

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***Abstract*—Local reactive power control of distributed generators (DG) can be used to mitigate the voltage rise effect caused by themselves. In this paper, dynamic interactions between local voltage controllers of the DG units and transformer on load tap changers (OLTCs) are studied using time domain simulations. Studies are conducted with different control modes of DG unit and OLTC control and also secondary substation tap changers are considered. Several types of adverse interactions are identified in the simulations: unnecessary OLTC operations can occur, reactive power transfers can unnecessarily increase and consecutive tap changer operations can occur in case of cascaded OLTCs. The paper gives also some general planning guidelines to avoid the adverse interactions identified in the simulations.**

***Index Terms*-- Cascaded tap changers, Distributed generation, Distribution network dynamics, Decentralized control, Voltage control**

## I. Introduction

Distributed generation (DG) can cause voltage rise problems in the existing distribution networks and local reactive power control of the DG units is one of the measures that can be taken to mitigate the voltage rise. In many countries (e.g. in Germany [1]), local reactive power control is a requirement for DG network interconnection. When DG reactive power control is taken into use, distribution network voltage is no longer controlled only by the primary substation on load tap changer (OLTC) and dynamic interactions between the different local voltage controllers will occur. Some studies on these dynamic interactions have been previously conducted and also adverse interactions have been reported. The number of tap changer operations can increase, the reactive power flows can increase and in some cases DG local reactive power control can in fact worsen the network voltage profile [2], [3].

In this paper, the adverse interactions between OLTC and DG voltage controllers are further studied. In the previous studies, a tap changer was available only at the primary substation. Installing tap changers also to secondary substations has, however, been suggested [4] and MV/LV transformers with tap changers already exist. This paper considers besides the HV/MV OLTCs the MV/LV OLTCs and voltage controllers of generators. This paper also deepens the analysis on the reasons for the different types of adverse interactions and gives general guidelines to prevent them.

## II. Study Method

Time domain simulations conducted using PSCAD transient simulation program are used to study the interactions between OLTC and DG unit local controllers in distribution networks. Simulations have been conducted using two different network models having adjustable network parameters. Different control modes and parameters of the local controllers are used in the simulations.

### *A. Network models*

The structure of the two simulation networks is presented in Fig. 1. In the first simulation case the DG units are connected to the MV network and the main aim is to study the interactions between the primary substation OLTC and the DG units. Also the operation of MV/LV tap changers is examined but their effect on the controller interactions is small as they can affect the operation of other controllers only through changing the voltage-dependent loads connected to their secondary. In the second simulation case the DG units are connected to the LV networks and the main aim is to study the interactions between the OLTCs both on primary and secondary substations and the DG units. If the MV/LV tap changers are not used, the studies do not significantly differ from the studies using the first simulation case.

In both simulation networks, the distribution lines are modeled using a π-connection and the lengths of feeders can be varied. Load type can be set to constant impedance, constant current or constant power. The primary substation HV/MV transformer always contains a tap changer and in part of the simulations tap changer is available also at the secondary substation MV/LV transformers. HV network voltage can also

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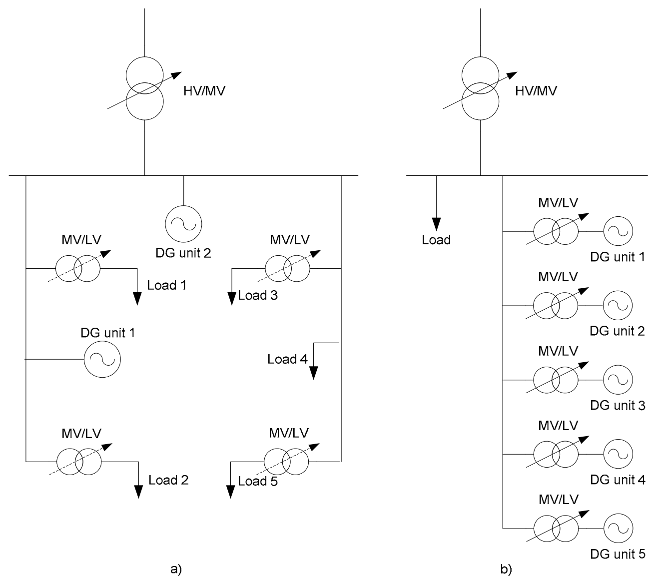


Figure 1. The structure of a) the first and b) the second simulation network.

be changed. Parameters of network components are similar in both simulation cases and are presented in Table 1.

TABLE I. NETWORK PARAMETERS ARE BASED ON PARAMETERS OF REAL NETWORK COMPONENTS.

| | |
|---|---|
| HV network | $S_k$ = 1 GVA, R/X=1/6 |
| MV line | R = 0.281 Ω/km, X = 0.344 Ω/km, B = 3.46 µS/km, lengths varied |
| HV/MV transformer | 110 kV/30 kV, 32 MVA, Ux=11.09 %, Ur= 0.41 %, tap step = 1.67 %, 25 tap positions ( ±12), mechanical tap delay = 2 s |
| MV/LV transformer | 30 kV/0.4 kV, 1 MVA, Ux=4.97 %, Ur= 0.5 %, tap step = 2 %, 7 tap positions (±3), mechanical tap delay = 2 s |

The network models include a time domain model of the automatic voltage control (AVC) relays that control the transformer tap changers [5]. The AVC relay measures the substation voltage and compares it with its reference voltage $U_{ref}$. If the measured voltage $U_{meas}$ differs more than the AVC relay dead band $DB$ from the reference voltage, a delay counter is started. This counter remains active as long as the measured voltage is outside the hysteresis limits of the relay and a tap change operation is initiated when the counter reaches the delay setting value. The delay can be constant or dependent on the voltage difference between the measured and the reference voltages. In this paper, inverse time characteristic is used and the delay $T_d$ is

$$T_d = T_{d0}\frac{DB}{|U_{ref}-U_{meas}|}, \quad (1)$$

where $T_{d0}$ is the delay set to the relay [5]-[6]. In case of cascaded OLTCs, time grading is used to coordinate the time domain operation of them i.e. MV/LV transformer AVC relays have larger delays than HV/MV transformer AVC relays [7]. Both constant voltage mode and line-drop compensation (LDC) mode are considered in this paper. In LDC mode the substation voltage is not kept constant but depends on the current flowing through the transformer. The substation voltage is increased at high transformer load and decreased at low transformer load. [5]

The DG units are modeled in PSCAD using a current source model. Three reactive power control modes of DG units are used in the simulations: constant power factor, $\cos\varphi(P)$ and $Q(U)$ as mentioned in [1]. In constant power factor and $\cos\varphi(P)$ control modes, the reactive power set point of the inverter depends on the measured real power and in the $Q(U)$ control mode on the measured voltage at the connection point. The characteristics of the $\cos\varphi(P)$ and $Q(U)$ control modes are represented in Fig. 2. The inverter dynamics related to the reactive current controller are represented using a first order transfer function

$$H_{inv} = \frac{1}{1+\tau_{inv}s}, \quad (2)$$

where the time constant $\tau_{inv}$ can be adjusted [8].

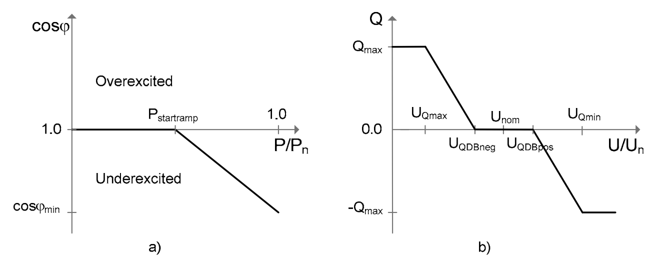


Figure 2. Characteristic of the a) $\cos\varphi(P)$ and b) $Q(U)$ control mode [1].

Two types of disturbances are used in the simulations presented in this paper to initiate control actions: DG real power changes and HV network voltage changes. In the former case, the DG unit reactive power control reacts to the disturbance in all control modes whereas, in the latter case, only the DG units in $Q(U)$ control mode react. Also simulations with loading changes were conducted but the results are quite similar to the results in case of HV network voltage changes and are not presented in the paper.

### *B. Control performance evaluation*

The main aim of distribution network voltage control is to keep network voltage quality acceptable [9]. This objective should be achieved utilizing the available control resources cost-effectively. The following issues need to be addressed when the performance of the combined controller operation is evaluated.

- The voltage quality has to be always acceptable and the control operation stable.
- The tap changers should be used only when they are really needed. Tap changer operations cause wear of the tap changer and can increase its maintenance need which increases the costs of the distribution system operator (DSO).
- Reactive power control should not unnecessarily increase losses. Losses increase when the reactive

power flow in the network increases. In most distribution networks, the losses increase when the DG units consume reactive power and, hence, reactive power consumption should be used only when it is really needed. There are, however, also networks where for instance lightly loaded cables produce reactive power and DG unit's reactive power consumption can help to decrease the losses [10].

- Reactive power control should not unnecessarily increase the reactive power fees paid by the DSO to the transmission system operator (TSO). In Finland, the reactive power flow between the distribution and transmission networks has to be kept inside a reactive power window determined by the Finnish TSO Fingrid [11]. In [12], the authors report of large reactive power fees which motivate the installation of compensation equipment. With the publication of the Demand Connection Code [13], the technical framework for the requirements on the reactive power exchange between transmission and distribution networks will be specified and harmonized.

The first bullet is critical and its terms need to be fulfilled always. The following ones describe the desired operation of the control system but the distribution network operation is not compromised if they are not always complied with.

## III. Identified Adverse Interactions

### A. DG reactive power control causes unnecessary OLTC operation

When some simplifying assumptions are made, the voltage change $\Delta U$ caused by a DG unit can be calculated as follows:

$$\Delta U = \frac{RP + XQ}{U_N}, \tag{3}$$

where $R$ and $X$ are the network resistance and reactance seen by the DG unit, $P$ and $Q$ are the real and reactive powers of the DG unit and $U_N$ is the nominal voltage. Because the $R/X$-ratio of distribution feeders is not negligibly small, DG real power production causes voltage rise in the network. This voltage rise can be mitigated by DG reactive power consumption.

On the other hand, the $R/X$-ratio upwards from the primary substation is quite small and the transformer has also an almost purely inductive reactance which is non-neglibigle. Hence, the combined effect of the DG real and reactive powers is not similar on distribution network feeders and on the primary substation. It is possible that the voltage at the DG connection point on the feeder increases but the voltage at the substation decreases at the same time due to the different $R/X$-ratios. This difference in the $R/X$-ratios leads to adverse interactions between the OLTC and DG unit voltage controllers in certain situations.

Fig. 3 shows example simulation results in the first simulation network where the DG units operate in $\cos\varphi(P)$ control mode with the parameters $P_{start}$ = 0.5 p.u. and $\cos\varphi_{min}$ = 0.8 (see Fig. 2) and the nominal power of both DG units is 10 MVA. The primary substation AVC relay is operating in constant voltage mode with a reference voltage of 1.0 p.u.. The dead band is ±1 % and the delay of inverse time operation $T_{d0}$ is 30 s. DG unit 1 is located 30 km from the substation and DG unit 2 1 km from the substation. Changes in the real power of the DG units are used as disturbances and the simulation sequence is selected such that interactions between the different local controllers are clearly visible. Fig. 4 presents simulation results using the same simulation sequence but with the DG units operating in $Q(U)$ control mode. The dead band $U_{QDBneg}$ – $U_{QDBpos}$ is 0.99-1.01 p.u., $U_{Qmax}$ is 0.96 p.u., $U_{Qmin}$ 1.04 p.u. and $Q_{max}$ 0.75 p.u. (see Fig. 2). The inverter time constant is in both cases 1 s.

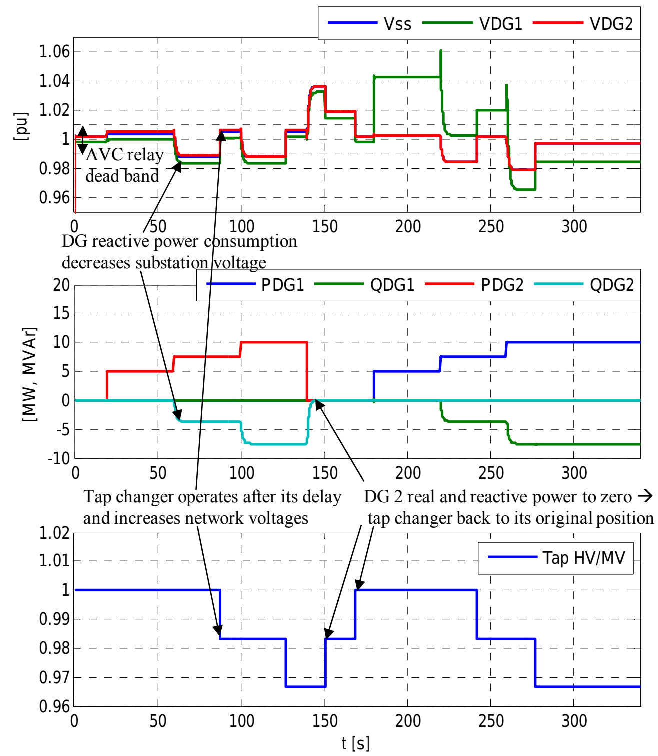


Figure 3. Unnecessary tap changer operations when the DG units operate in $\cos\varphi(P)$ control . The uppermost figure presents the substation voltage $Vss$ and the terminal voltages of the two DG units. The second figure presents the real and reactive powers of the two DG units and the lowest figure includes the HV/MV-transformer tap position.

Unnecessary tap changer operations can be seen both in Fig. 3 and in Fig. 4. The mechanism that causes these tap changer operations is the same in both cases: The DG units consume reactive power based on their control characteristics that are required to mitigate the distribution network voltage rise caused by the DG units. The reactive power, however, affects the voltage at the substation and at the DG connection point differently. The $R/X$-ratio upwards from the primary substation is usually relatively small and, therefore, the substation voltage often decreases although the feeder voltages can be larger than without the DG unit. If the substation voltage decreases below the AVC relay dead band limit, the tap changer operates to increase the network voltages. Hence, there is an interaction between the two local controllers where the DG reactive power controller aims to decrease DG connection point voltage and the AVC relay opposes this control action by increasing the network voltages.

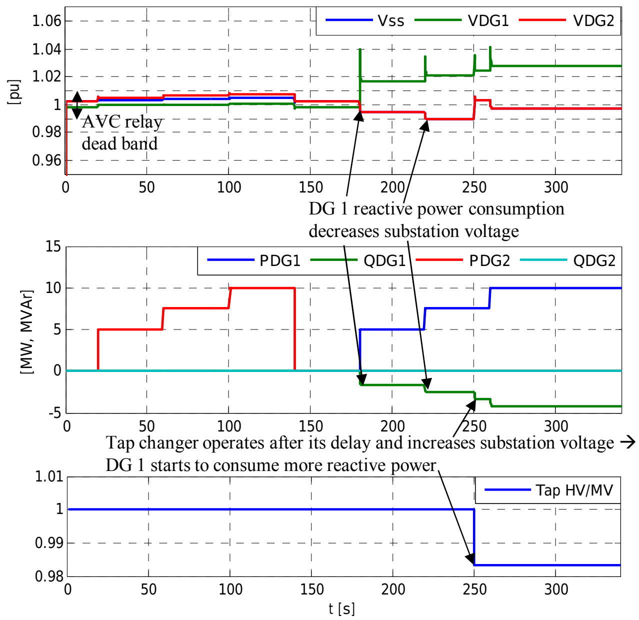


Figure 4. Unnecessary tap changer operations when the DG units operate in $Q(U)$-control mode.

The number of unnecessary tap changer operations is different depending on the control mode. In $\cos\varphi(P)$ control mode the reactive power output of the generators is dependent only on the real power output of the units. The location of the DG unit does not affect its reactive power output and the reactive power outputs of DG units 1 and 2 are equal in Fig. 3. When the real power of either of the DG units is increased from zero to the nominal power, two tap changer actions are initiated. It should be noted that when $\cos\varphi(P)$ control mode is used, reactive power is consumed also when it would not be necessary. DG unit 2 is located close to the substation and its real power production does not affect network voltages significantly. The reactive power consumption, however, does have an effect on the voltages because the $R/X$-ratio seen by the DG unit is relatively small and several unnecessary control actions are performed.

When the DG units operate in $Q(U)$ control mode, reactive power is consumed only if the terminal voltage of the DG unit increases enough. As DG unit 2 is located close to the substation, its real power production is not able to increase the terminal voltage significantly and reactive power is not consumed. DG unit 1 is located farther away from the substation and real power production increases the feeder voltages. Reactive power is consumed to mitigate the voltage rise. On the feeder, the voltage level remains higher than without the DG unit but at the substation the voltage decreases and the tap changer operates to increase the substation voltage. This change in substation voltage increases also the DG unit connection point voltage and the reactive power consumption increases based on the control characteristics.

The same simulation sequence was run also using constant power factor control. In the case of unity power factor, the real power changes alone are not able to change the substation voltage substantially and, hence, additional tap changer actions do not occur in the example case. DG 1 connection point voltage, however, increases to 1.08 p.u. at nominal DG power. In this case, the MV feeder voltage limits are set to 0.95-1.05 p.u. and, therefore, the unity power factor operation is not acceptable. The cases with constant inductive power factor are quite similar to $\cos\varphi(P)$ control case.

The example cases shown in Fig. 3 and Fig. 4 were selected such that the adverse interactions would be easily visible. The DG units are large and have relatively large reactive power capability. Simulations have been conducted also in several other cases. Unnecessary tap changer operations are possible in all control modes that use reactive power consumption to mitigate the voltage rise caused by the DG units. In the simulations, the probability of unnecessary tap changer operations increases when the nominal power and/or reactive power capability of the DG units is increased. In case of $\cos\varphi(P)$ control, the location of the DG unit does not change its effect on tap changer operation but in case of $Q(U)$ control the amount of consumed reactive power increases when the DG unit is located farther away from the substation and, hence, also unnecessary tap changer operations can be seen more often. If the dead band in the $Q(U)$ control is decreased, DG units closer to the substation will start to cause unnecessary tap changer operations and vice versa. Also the original HV voltage level affects the simulation results. If the transformer secondary side voltage is already near the dead band limit at the start of the simulation, even small changes in DG unit powers can lead to tap changer operations whereas if the voltage is at the center, relatively large changes are needed to cause a tap changer operation.

The control mode and parameters of the substation AVC relay affect the results significantly. In the simulation results of Fig. 3 and Fig. 4, the AVC relay is operating in constant voltage mode. If the AVC relay is operated in LDC mode and the parameters are properly selected, the unnecessary tap changer operations can be prevented because the substation voltage set point is decreased when the transformer loading decreases due to increase in production. This is a suitable choice if all network voltages remain at an acceptable level in all possible loading and production conditions also with the LDC. If the effect of DG has not, however, been taken into account when selecting the LDC parameters, it is possible that a production increase on one feeder causes too low voltages in some adjacent pure load feeder [14].

The operation of the MV/LV-transformer OLTCs is shown in Fig. 5 in the case where DG unit 1 operates at constant power factor of 0.9. The real power output the DG unit is increased from zero to 5 MW at time 20 s. The DG unit is located 30 km from the substation, load 1 15 km from the substation and load 2 1 km after the DG unit. At the adjacent feeder, load 3 and 5 are located 1 and 12 km from the substation, respectively. All the AVC relays are operating in constant voltage mode and the dead bands are set to ±1 % in the HV/MV-transformer and to ±1.2 % in the MV/LV-transformers (1.2*tap step). The delay of inverse time operation $T_{d0}$ is 30 s in the HV/MV OLTC and 60 s in the MV/LV OLTCs. In this example case, the unnecessary tap changer action in the primary substation leads to tapping of all the MV/LV-transformers on the DG feeder to the opposite direction. These tap changer operations are advantageous from the customer voltage point of view but the number of tap

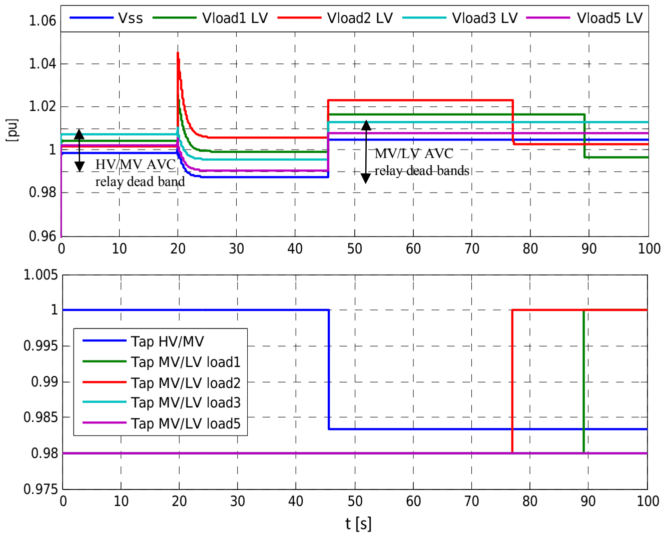


Figure 5. Unnecessary primary substation operation causes secondary substation tap changer operations. The upper figure contains the transformer secondary voltages used in AVC relay control and the lower figure the tap positions. DG 1 real power increases from 0 MW to 5 MW at time 20 s.

changer operations can become large which increases the tap changer maintenance costs. A large number of secondary substation OLTC operations can occur also in cases where the unnecessary primary substation OLTC operations are prevented by using the primary substation AVC relay in LDC mode. In this case, DG real power production decreases the primary substation voltage and, hence, also voltages on all feeders that do not include DG. If these feeders include MV/LV OLTCs, they will operate to keep the LV side voltage within their control limits introducing a large amount of tap changer operations.

## *B. DG reactive power flow increases unnecessarily*

DG units operating in $Q(U)$ control mode respond also to network voltage changes originating from other sources than the DG unit itself (changes in HV network voltage, loading changes etc.). If the voltage controllers of the DG units are faster than the OLTC controller, it is possible that the DG units start consuming or producing a large amount of reactive power and prevent the operation of the OLTC in situations where OLTC operation would be the preferred control operation. In Fig. 6 one such example case is represented. DG unit 1 is producing its nominal power 10 MW and operates in $Q(U)$ control mode with the same parameters as in Fig. 4. The DG reactive power control is significantly faster than the OLTC control (inverter time constant is 1 s and the AVC relay delay of inverse time operation $T_{d0}$ is 30 s). When the HV voltage increases, the DG unit starts to consume more reactive power and the substation voltage re-enters the AVC relay dead band and the tap changer does not operate. The reactive power transfer in the network remains higher than before the change in the HV network voltage. This kind of operation can occur when the $Q(U)$ control is operating at the droop part of its control characteristic and is more pronounced if the DG unit is located closer to the substation. On the other hand, DG units located close to the substation operate usually in the dead band area of their control characteristic if the parameters have been properly selected.

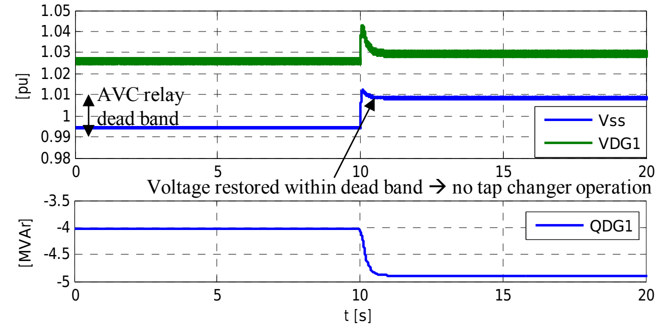


Figure 6. DG reactive power control prevents OLTC operation. The HV voltage increases at time 10 s.

## *C. Secondary substation OLTC operations cause operation of the primary substation OLTC*

In the second simulation case, the DG units are connected to LV networks and there are OLTCs on the MV/LV – transformers. If the reactive power of the DG units does not depend on the measured voltage i.e. they are operated in constant power factor or $\cos\varphi(P)$ mode, the interactions between controllers are similar to the ones presented in section III.A. If the DG units are, however, operated in $Q(U)$ control mode, new type of interaction is introduced. When the MV/LV OLTC operates and the LV network connected DG units are used in $Q(U)$ control mode, the voltages at the primary and secondary substations change in opposite directions. If the MV/LV OLTCs increase their secondary side voltages, the DG units increase their reactive power consumption and, hence, the primary substation voltage decreases. This can induce an HV/MV OLTC operation. This interaction is illustrated in Fig.

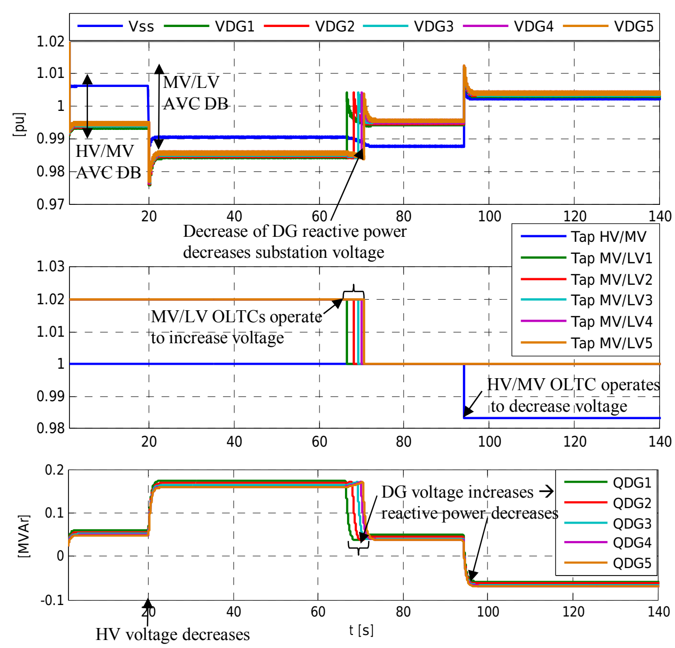


Figure 7. MV/LV OLTC operations cause HV/MV OLTC operation.

7. No dead band is used in $Q(U)$ control and $U_{Qmax}$ is 0.96 pu, $U_{Qmin}$ 1.04 pu and $Q_{max}$ 0.5 p.u.. All feeder lengths are set to 1 km.

Several simulations were conducted to determine whether tap changer hunting could be possible due to the opposite voltage change in primary and secondary substation after MV/LV OLTC operation. Unstable operation was not visible in any of the simulations even when the control system parameters were purposely poorly selected trying to invoke hunting. With unrealistic controller parameters it was possible to invoke three tap changer operation steps i.e. one additional operation of all MV/LV OLTCs occurred after the HV/MV OLTC operation of Fig. 7 but after that the system stabilized.

## IV. PREVENTING THE ADVERSE INTERACTIONS

If only local controllers are utilized, it is not possible to avoid all unnecessary control actions presented in the previous chapter. Proper selection of control modes and control parameters can, however, decrease the number of unnecessary control actions substantially.

Unity power factor control is usually the most advisable option if reactive power control is not needed either to mitigate the voltage rise caused by the DG unit or to control the reactive power transfer between the distribution and transmission systems. If the DG unit is connected near the substation it does not cause a significant voltage rise. If the DG unit is connected on a dedicated feeder, the magnitude of the supply voltage is not determined by the standard EN 50160 [9] and can, hence, be agreed to a suitable value. DG reactive power control is not needed for distribution network voltage control purposes in either case. If reactive power control is in these cases needed to keep the reactive power transfer between the distribution and transmission systems at an acceptable level, constant power factor or constant reactive power control mode should be used.

Reactive power control should, naturally, be used if it is needed for distribution network voltage control. Selecting the control mode is not, however, obvious. The number of unnecessary tap changer operations due to changes in DG unit real power is larger when constant power factor or $\cos\varphi(P)$ control is used compared to $Q(U)$ control. Therefore, the wear of the tap changer is larger using those control modes. On the other hand, the interactions introduced in sections III.B and III.C are possible only if the DG units operate in $Q(U)$ control mode. Moreover, if the parameters of the $Q(U)$ control are not properly selected, the local control can become unstable [8].

In $Q(U)$ control, using a dead band is advisable. Suitably selected dead band decreases the probability for large reactive power transfers (section III.B) and consecutive MV/LV and HV/MV OLTC operations (section III.C). Also the number of unnecessary primary substation OLTC operations (section III.A) is smaller when a dead band is used. Also, the droop should not be too steep to guarantee stability of the local control and to decrease the probability for the aforementioned adverse interactions.

The dead band of the AVC relays should be also properly selected. If it is too small, the number of unnecessary OLTC operations increases and the interaction presented in section III.C will be seen more often. If it is too large, the voltage quality of the network can be worsened and it is more probable that large reactive power flows will replace the tap changer operations (section III.B). Unnecessary OLTC operations can, in some cases, be prevented by using the AVC relay in LDC mode but it has to be made sure that the network voltage quality is secured, meaning that the LDC parameters must be tuned to the individual network situation.

## V. CONCLUSIONS

Three types of adverse interactions between local transformer tap changer control and local reactive power control of distributed generators have been identified and simulated in this paper. In addition to introducing the adverse interactions, the paper also discusses the reasons for them and provides general guidelines for selecting the control modes and parameters of voltage controllers properly.

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