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Glossary

For a list of main vocabulary used throughout the Net2DG project, see Deliverable 1.2. The following technical terms are used specifically in this report.

AMI	Advanced Metering Infrastructure
AVR	Automatic Voltage Regulation
Local control	Voltage control built into inverter; measures and regulates (active and reactive) power output to local busbar to maintain stable voltage based on local measurements only
Coordinated (or coordination) control	Voltage control that overrides setpoints in local controllers to achieve a desired voltage profile throughout a grid section (typically a feeder).
DSO	Distribution System Operator
MPPT	Maximum Power Point Tracking
PV	Photovoltaic generator
RGM	Reference grid model
DER	Distributed energy resource
OGM	Observability Grid Model
OLTC	On-load tap changer
SCADA	Supervisory control and data acquisition
TME	Thy-Mors-Energi (Distribution System Operator, partner in Net2DG)

1 Executive Summary

This report documents the initial coordination control design undertaken in Work Package 4.

Taking the starting point in the Automated Voltage Regulation use case identified in Deliverable 1.2, one low voltage grid radial from the TME field study is selected as a representative test case. A grid model of this radial developed in Work Package 2 is adopted and modified for the present study to highlight a potential over-voltage situation. An optimization-based coordination control scheme is then formulated, and it is demonstrated that the problem can be solved and commands issued to the controllable inverters connected to the grid, forcing them to change their reactive power behaviour and decrease the voltage on the busbars such that the voltage along the radial converges to within the permitted bounds.

The initial simulations are undertaken in MATLAB/Simulink, followed up by a Java app to be included in the Net2DG framework.

An initial coordination control is achieved in this release. Future work involves considering more advanced scenarios, studying problem complexity and scalability, as well as potentially investigating different inverter operation modes.

2 Introduction

The overall goal of introducing coordination control in the low voltage distribution grid in Net2DG is to make room for as many renewable assets as possible without violating voltage band limits. One may thus think of the coordination control design presented in the following as a kind of strategic control system. Coordinated control will be attempted in accordance with the general limitations of the field equipment, communication frequency and large scale of the system; the attention will be limited to voltage quality at 10 minute voltage averages, so voltage dips and swells will not be considered.

For a thorough overview of the current state-of-the-art, see [1].

2.1 Use case

The Automatic Voltage Regulation use case was initially outlined in Deliverable 1.1 [2]. It essentially involves the Net2DG system detecting (via Grid Monitoring) the presence of voltages in the LV grid being out of bounds for extended periods of time and reacting on this information to mitigate the situation. In order to make the use case more concrete and amenable to analysis and design, three scenarios illustrating such situations are described below. However, a few general observations are made first.

From a PV generation perspective, it is chosen to focus on over-voltage situations due to DER generation (infeed) and measures against these. Low voltage will be due to loads. Becoming aware of such a situation is the main benefit of grid monitoring for the DSO. However, it is usually solved by the conventional grid reinforcement (e.g. a new/parallel cable).

In general, grid-codes around the world increasingly require DER generators to have voltage control functions available (ranging from autonomous controls to remote control, e.g. according to the prospective California Rule 21 [3], which may or may not find its way to Europe as well). The grid-codes currently applicable in the ENTSO-E region may be found in [4].

Remotely controlled OLTCs can basically be discounted, and they do only help where generation (infeed) is rather equally distributed along the feeders. If there is one feeder with heavy PV penetration and other load-dominated feeders, then stepping down might help maintaining proper voltage levels on the one feeder, but might increase the probability of undervoltage at the others.
Typically, the secondary substations in LV grids are equipped with a manual tap-changer mainly due to cost but also connectivity to SCADA systems which are not yet available for most of European DSOs.

In order to make the AVR use case more amenable to actual simulation studies, a number of scenarios where coordination control could be useful in the context outlined above, are formulated in the following.

2.1.1 Scenario 1

The first scenario considered is one where overvoltage is generated along a feeder due to high PV production; the aim is to achieve an optimum/economic distribution of grid support to counteract over-voltage due to multiple generators along feeder, with the target of maximum DER hosting capacity without grid reinforcement.

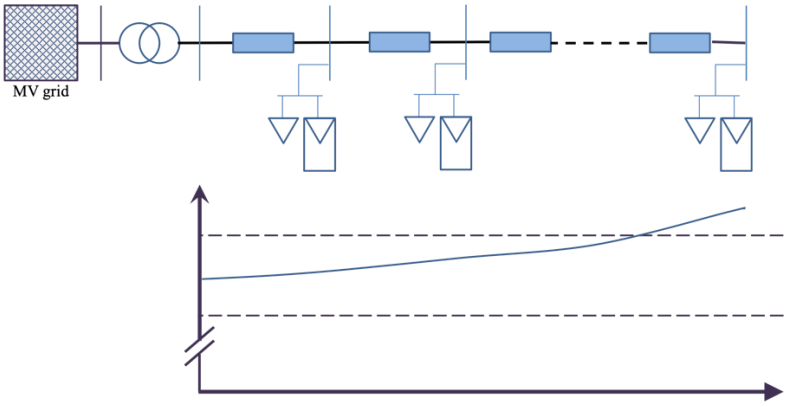

Figure 1 Over-voltage due to multiple generators along feeder in LV grid.

Here a long feeder is considered with plenty of (each branch bus) PV installed. On a sunny day, each PV outputs (active) power to the LV grid in excess of what is consumed by loads. As a consequence, the voltage rises along the feeder. In this scenario, the situation is bad enough to cause over-voltage somewhere along the feeder as well as possible upstream power flow (which may or may not be an additional issue). Local control (discussed later) may deal with the voltage issues as such, but the particular, grid-supporting modifications in active/reactive power should be shared fairly among the PV inverters – which is where coordination control comes into play.

The overvoltage issue is detected by means of analysing data gathered from meters and inverters. In this case, power curves (active and reactive production) can be sent from a central coordinating agent (the AVR app in the Net2DG system) to several PV inverters along the feeder. Then, each PV inverter with the local control is forcing the voltage down (not shown) via coordination. The coordination control is trying to obtain a fair distribution of their contribution between the different inverters. Although the local-control is in operation based on the its strategy, in the worst case, the generator's interface protection (i.e. the voltage trip limits) will disconnect the unit.

2.1.2 *Scenario 2*

The scenario is a variation of Scenario 1, where the goal is still to achieve an optimum distribution of grid support to counteract over-voltage due to multiple generators along feeder, but in this scenario a controllable storage element – e.g., a battery – is also available for the coordination control. Notice that this scenario is considering a battery that is owned by DSO while the PVs are still private.

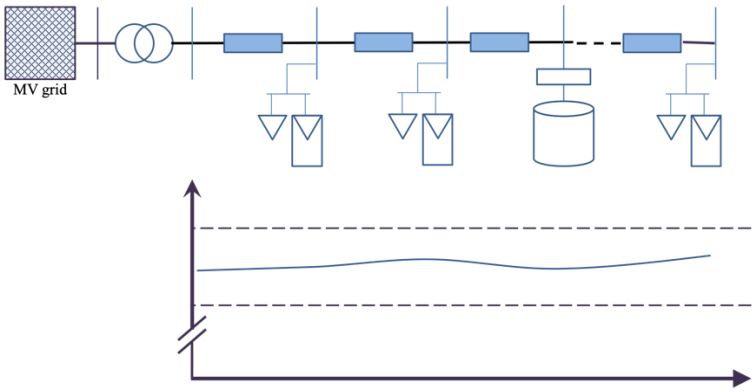

Figure 2: Energy storage system in LV grid.

This scenario is much like Scenario 1, but in this case, it is assumed that the DSO has installed a battery behind an inverter (the oblong box above the storage shown in Figure 2), which can be used for voltage control along the feeder. Even though current regulatory frameworks may provide some obstacles to this scenario of DSO operated batteries, it was decided to include it as a potential idea for expansion. Basically, the idea is to have the battery charge when there is a reverse power flow on the feeder on sunny days, and discharge whenever there is more consumption than production on the feeder.
it is believed [5] that DSO may own and operate batteries in the LV grids in the near future due to the optimal batteries' configuration that is highly dependent on the grid topology, application and generator configuration.

2.1.3 *Scenario 3*

This scenario considers reactive power balancing below (secondary) substation.

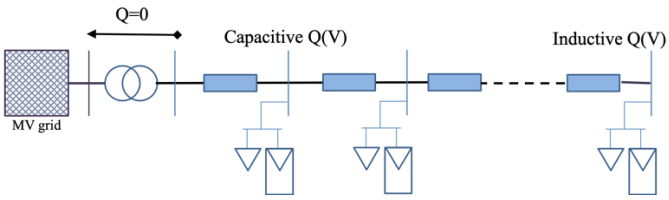

Figure 3: Coordinated reactive power management in LV grid.

In this scenario reactive power control ($Q(V)$ deployment) is considered with coordinated reactive power management with the aim of balancing the reactive power flows along the LV feeder lines, as shown in Figure 3. For example, one could aim to compensate for the inductive *Q* drawn by PV inverters, which are used for voltage support, close to the end of the feeder by a capacitive *Q* behaviour of PV inverters close to the MV/LV transformer station. The target could be zero reverse flow of *Q* through the transformer. The idea is to avoid Q flows from the upstream grid resulting from *Q*-based voltage management at PV inverters connected to the feeder(s) by balancing the reactive power on a subsidiary level. Theoretically, this would reduce the load of the transformer as well as the loss. It also can be expected that the life of the transformer could be extended.

2.2 Methodology

The overvoltage issue must be detected by means of analysing data gathered from measurement devices in the DSO grid and PV inverters. Once identified, *Q(V)* set-points shall be sent from a central coordinating agent (the AVR app in the Net2DG system) to several inverters along the feeder, forcing them to change their reactive power output to the local grid and thereby lowering the voltage. It is likely that overvoltage problems may tend to occur in the locations, which are far from the substation in long feeders. In the long term, the aim is then to obtain an optimum distribution of their contributions to voltage quality between the different PV inverters. Although the local-control is in operation based on the its strategy, in the worst case, the PV generator's interface protection (i.e. the voltage trip limits) will disconnect the unit; this is not considered at the coordination control level.

In short, the methodology can be summarized as follows:

1. Obtain information that voltage in a feeder on the LV grid is reaching specific limits.
2. Obtain information about reactive power in the PV inverters.
3. Obtain the sensitivity matrix regarding to the PV inverters.
4. Solve a constrained optimization problem with reactive power generation of PV inverters and calculate an optimum set-points of *Q(V)* for each PV inverters, and voltage limits as constraints.
5. Send set-points of *Q(V)* to the PV inverters and let them operate locally.
6. Monitor the grid until it is confirmed that the voltage is within bounds. Until it is, repeat the procedure periodically.

The first priority in this deliverable is to show a proof of concept, i.e., demonstrate that the procedure outlined above is feasible in the first place. The goals to be achieved for AVR Release 1 are therefore restricted to the following:

1. Only Scenario 1 will be considered for Release 1.
2. Assuming grid voltages and active/reactive power flows are available, which will be used for calculation of sensitivity matrix, it shall be demonstrated that it is possible to solve a simple coordination control problem using PV inverters as the only actuators.
3. It shall be demonstrated that the voltage is kept within voltage quality limits.

As stated, this methodology is rather limited in its applicability and likely needs to be improved upon in later releases. It relies on several assumptions, among others:

1. One representative radial feeder with large PV penetration
2. Each branch loads are static. The voltage along the feeder only changes as a result of PV inverters' actions.
3. Detailed grid topology information is available. This is necessary in order to estimate the effects of adjustment commands issued to inverters, not only locally but along the entire feeder.
4. All PV inverters in a given grid section are able to perform local voltage control according to commands of new settings for local control received from ICT-GW.
5. All is three-phase balanced. For representing reality closer, a 4-wire-model is needed.

Limitations to these assumptions will be addressed in future releases.

3 Low-Voltage Grid Model and Voltage Control

This chapter describes the simulation and local control models that the coordinated control is subsequently designed for. The grid model (cable lengths etc.) and amount of installed PV are tweaked to achieve an overvoltage situation at high PV infeed into the grid.

3.1 Grid model used for control

In this release, the Reference Grid Model (RGM) is used to validate the control method described later. It is a reasonably accurate dynamical representation of the real world used to reproduce events and operational challenges similar to daily operation of distribution grid. It was first presented in [6].

The RGM is representative of a radial section of a distribution grid. It is composed of six busbars with 11 loads and three PV generation units. The feeder is based on an actual grid belonging to Thy-Mors Energi, where the radial branch highlighted with the red oval was selected for the analysis.

However, initial simulation trials indicated that the voltage along the feeder was almost always well within the bounds when operated under nominal conditions. It was therefore decided to add more PV systems to the last bus, i.e., PV systems at junction box 10 and 16 as well as at 19, where the voltage has the largest sensitivity to active and reactive power variations, in order to achieve the situation described in Scenario 1 above. Moreover, it should be noted that the line length of each main bus and branch lines were extended in order to increase the line impedance, which in turn increases voltage sensitivity related to the active and reactive power flows. For the main bus lines, 5 times the lengths of the original ones are used, and for the branch lines, 20 times the lengths of the original ones are used.

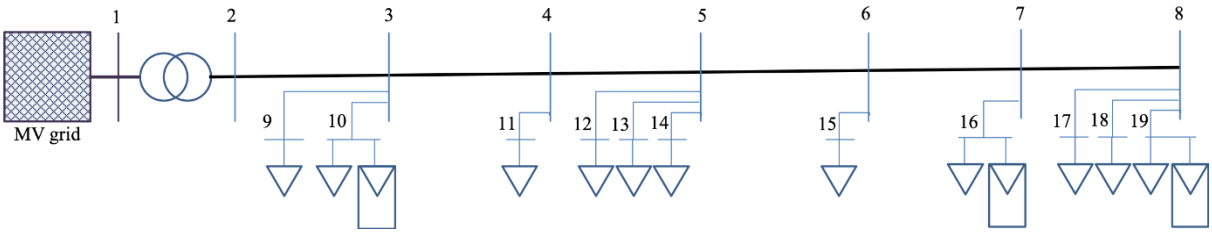

Figure 4: Single line diagram of the RGM.

3.2 Simulation of local control

As a preliminary study of the scenarios outlined above, and to highlight the pre-coordination control capabilities, three simple local control methods were implemented: Maximum Power Point Tracking mode without *P* or *Q* control (the PV systems inject all available power to the grid), *P(V)* Mode (the PV system reduces active power depending on the local grid voltage before reaching the upper voltage limit), and *Q(V)* Mode is related to operation as a function of grid voltage.
There are four sub-modes for reactive power control:

- Method 1 – reactive power is injected according to the imposed cos φ, i.e., cos φ (V).
- Method 2 – system is following a reactive power reference, i.e., Set $Q_{ref.}$
- Method 3 – reactive power is following a predefined characteristic function of the grid voltage ($Q(V)$).
- Method 4 – no reactive power is generated into the grid.

Figure 5 shows a simple model of the inverter control system considered in the simulation. Moreover, $Q(V)$ is corrected through Q_{cor} (later to be calculated by the coordination control); ℓ is the local droop of $Q(V)$.

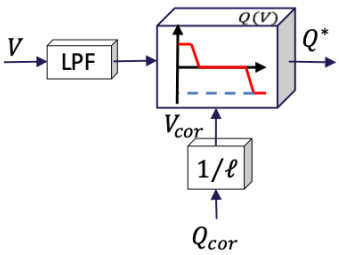

Figure 5 Control block diagram of local controller, showing how the correction signals (set-points) Q_{cor} from the coordination control enter the local controller. LPF denotes Low Pass Filter, while PI denotes Proportional-Integral control.

The following general assumptions are made for the subsequent simulations:

1. All generation and load are constant and three-phase symmetrical.
2. The upstream grid delivers enough power to supply the feeder.
3. There is no communication between any of the generators.
4. The sampling time is set to be faster in these simulations than what is considered in the rest of the Net2DG framework, since the intention is to verify the dynamic behavior of the local controllers before moving to coordinated control.
5. The *Q(V)* will be activated when the voltage is larger than 1.05 pu.

The graphs shown in Figure 6 and Figure 7 show the voltages on each bus simulated throughout one day without and with local control (but without coordination control), respectively.

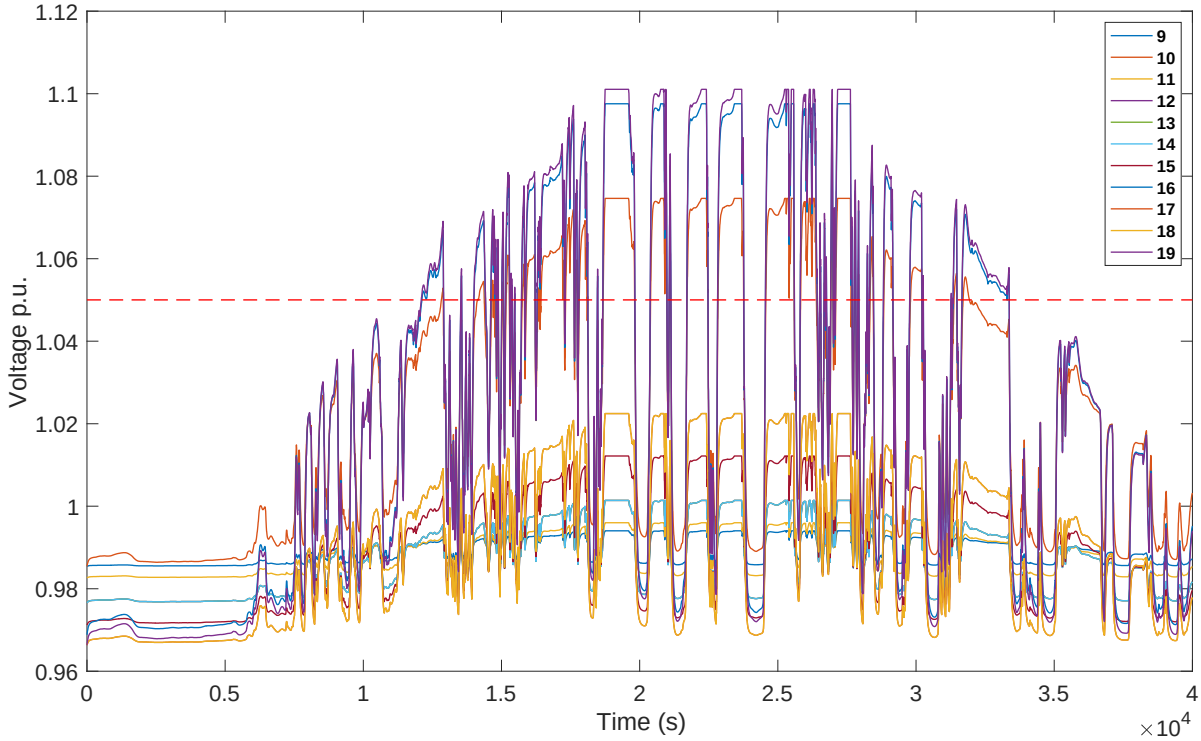

Figure 6 Each branch bus voltage without reactive power local control by PV systems.

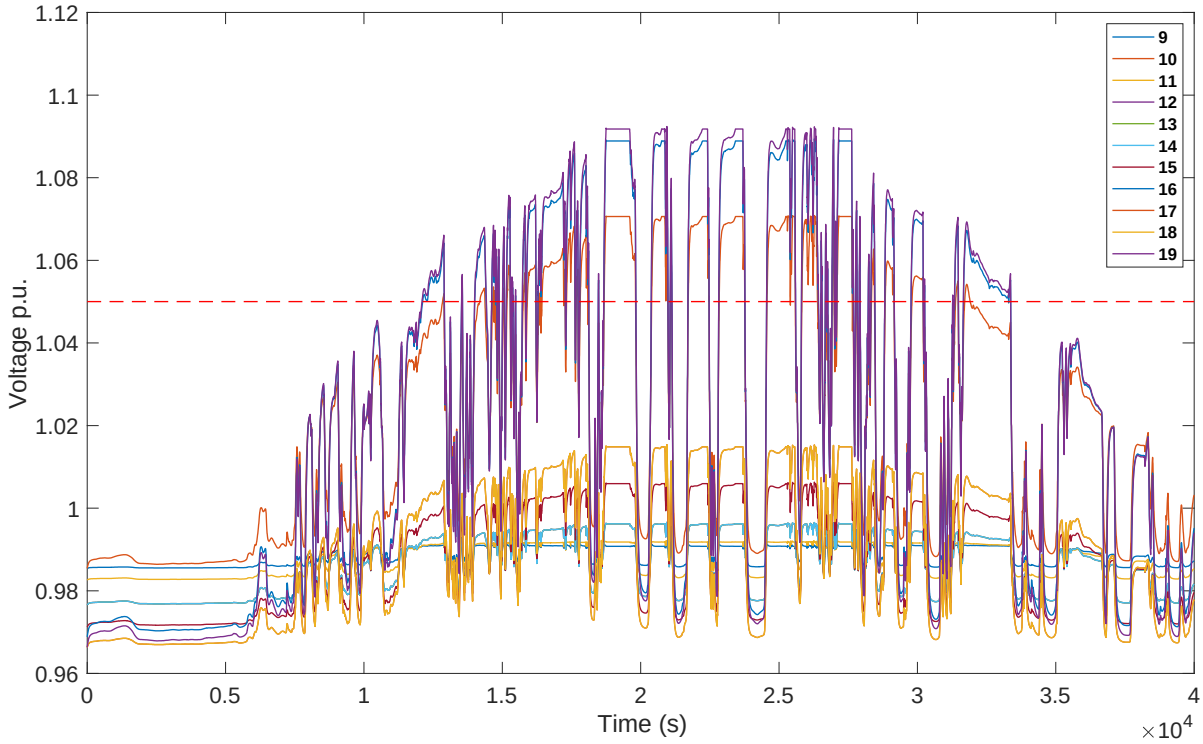

Figure 7 Each branch bus voltage with reactive power local control (Q(V)) by PV systems.

Compared to Figure 6, the highest busbar voltages do no longer touch the 1.1 pu limit. In addition, the voltage on the higher-numbered busbars is higher the 1.05 pu voltage limit during periods from 10000 to 33000 s, even though the voltage on the busbars close to the substation is well within the limits.

3.3 Local Control Simulation

In the following, the simulation is augmented with first local and then coordinated control in a hierarchical fashion as illustrated in Figure 8.

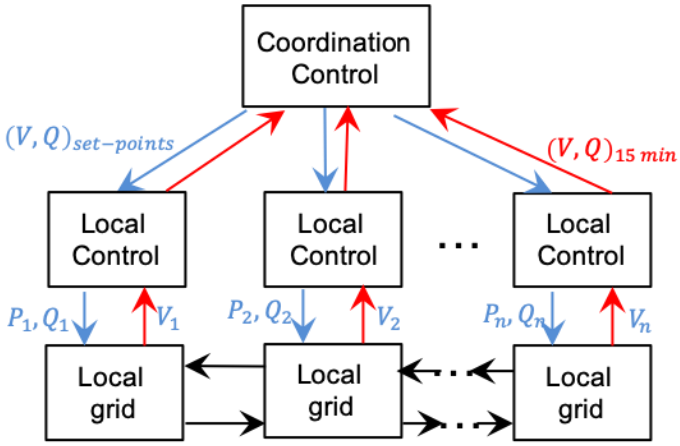

Figure 8 Control hierarchy

Conditions:

Ploadhouse	0.6 kW	Load (active power) of each house
Qloadhouse	0 Var	Load (reactive power) of each house
Rated of PgenPV	5 kW	Rated generation of PV system
Reactive power control	Q(V)	Function of V
Ctrl_act	0.3 s	Control active time

3.3.1 Test Scenarios

A benchmark test scenario is applied to account for the operational points of PV systems at their MPP. Figure 9 represents an example of a realistic generation profile over time.

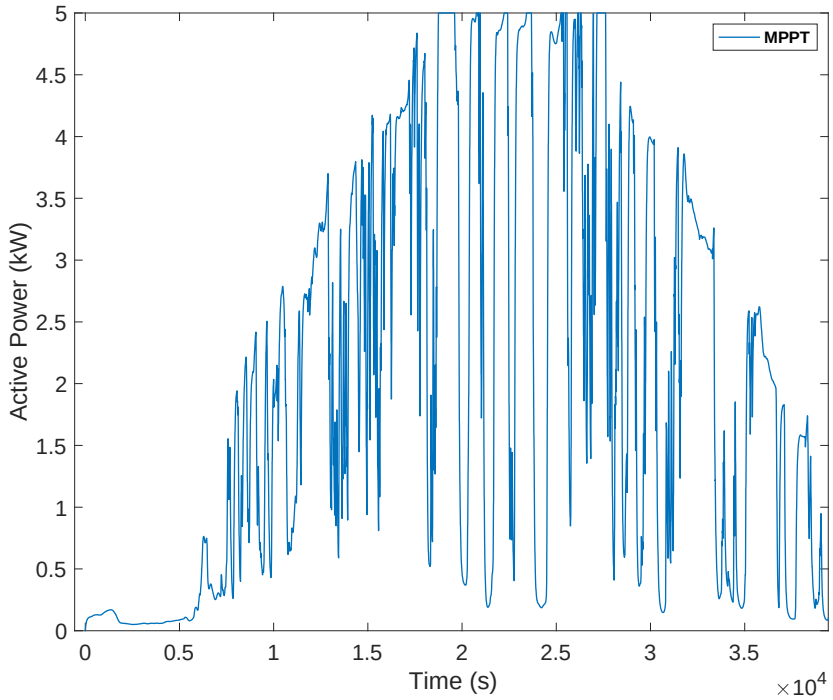

Figure 9 Active power generation of PV system.

In this study, we implemented three control methods: Q(V).
The time behaviour of the Q output follows a PT1 element (first order low pass) with the time constant tau=10/3=3,33 (means: target value reached after 3tau=10s)

3.3.1.1 *MPPT Mode Without Q Control*

Figure 10 shows the main bus voltage when the PV systems inject their MPP to the grid. Figure 30 shows each branch bus voltage when the PV systems inject their MPP to the grid. It can be seen that when the PV systems generate their rated power, the voltage at bus 19 is larger than 1.1 pu, which is usually not tolerable. It should be noted that no reactive power control is activated in this case. Figure 12 show the active power losses in the main bus.

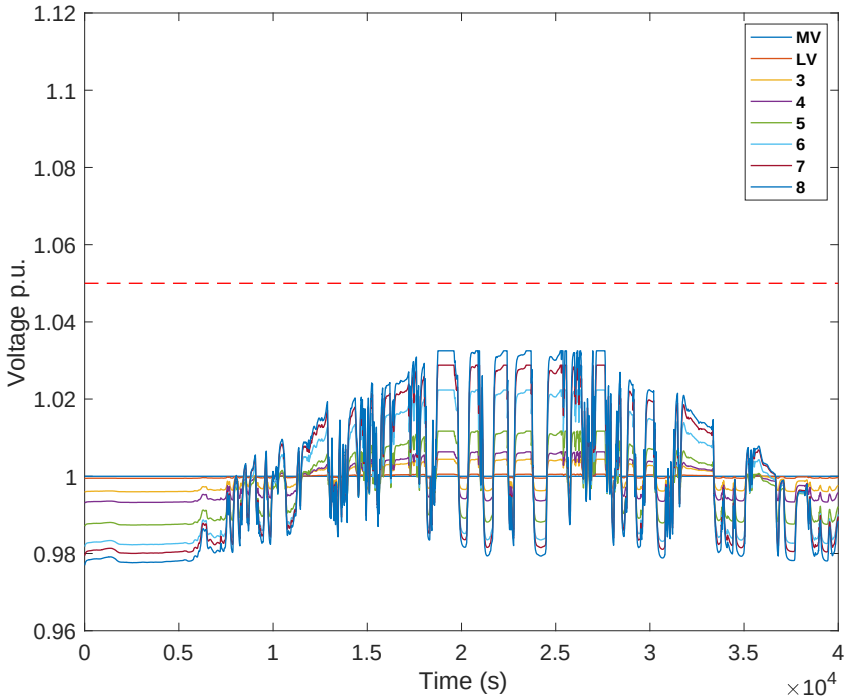

Figure 10 Main bus voltages without reactive power local control with PV systems.

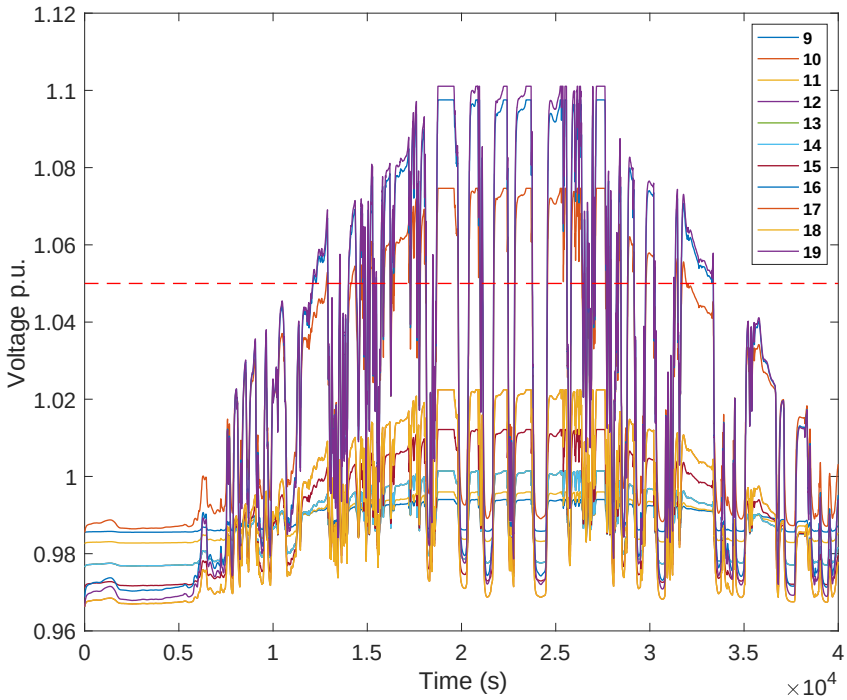

Figure 11 Each branch bus voltage without reactive power local control with PV systems.

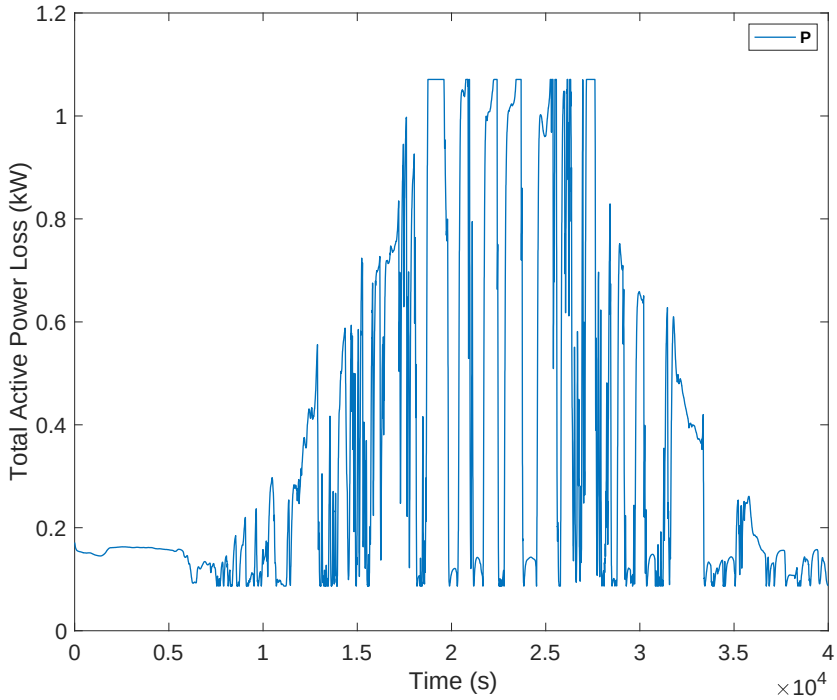

Figure 12 Total active power loss without reactive power local control.

3.3.1.2 *Q(V) Mode*

In this case, the PV systems inject the active powers to the grid, as shown in Figure 9. It can be seen that reactive power control Q(V) decreases the voltages to within 1.1 pu at the bus 19, as shown in Figure 14.

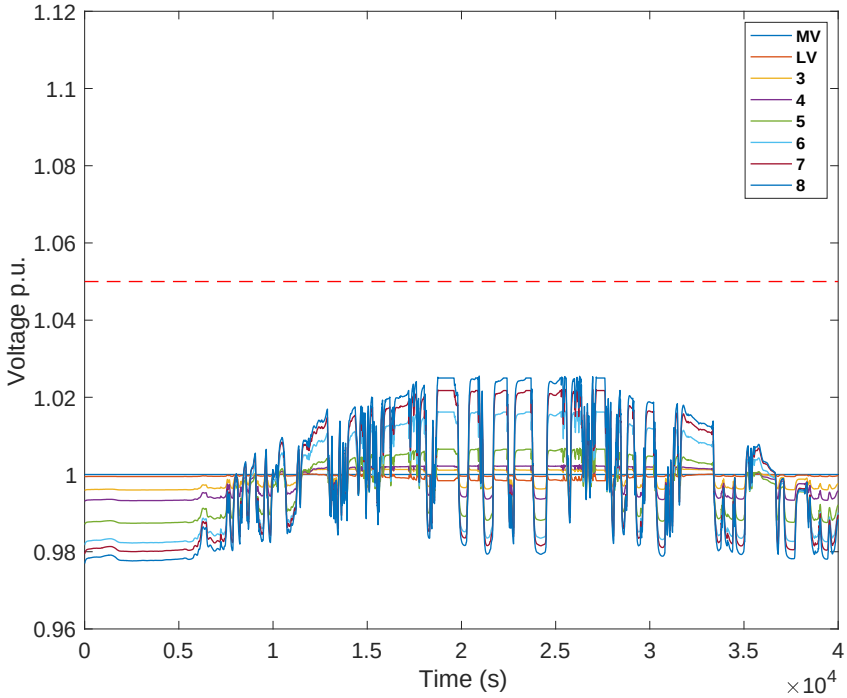

Figure 13 Main bus voltages with the reactive power local control (Q(V)) with PV system.

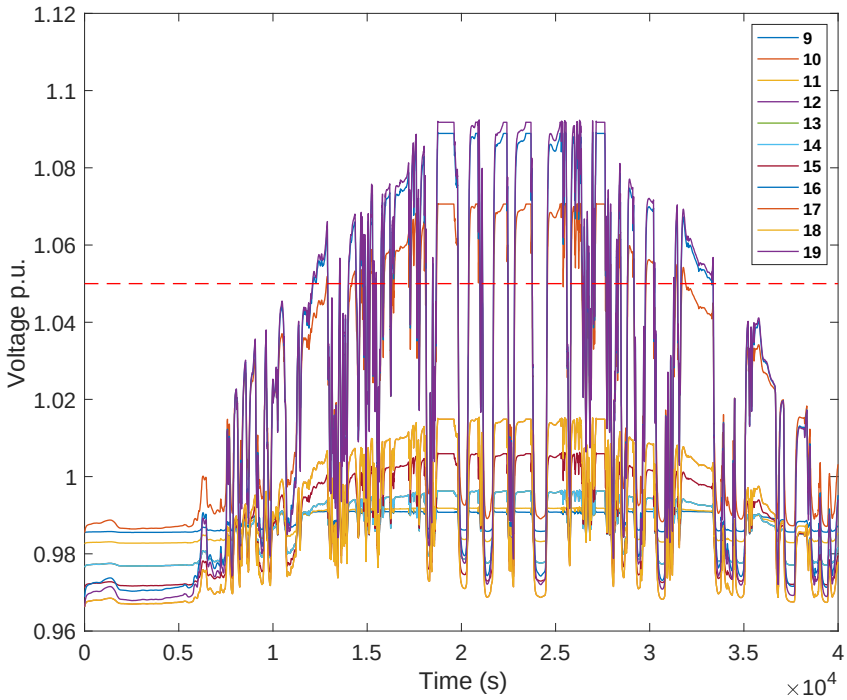

Figure 14 Each branch bus voltage with the reactive power local control (Q(V)) with PV system.

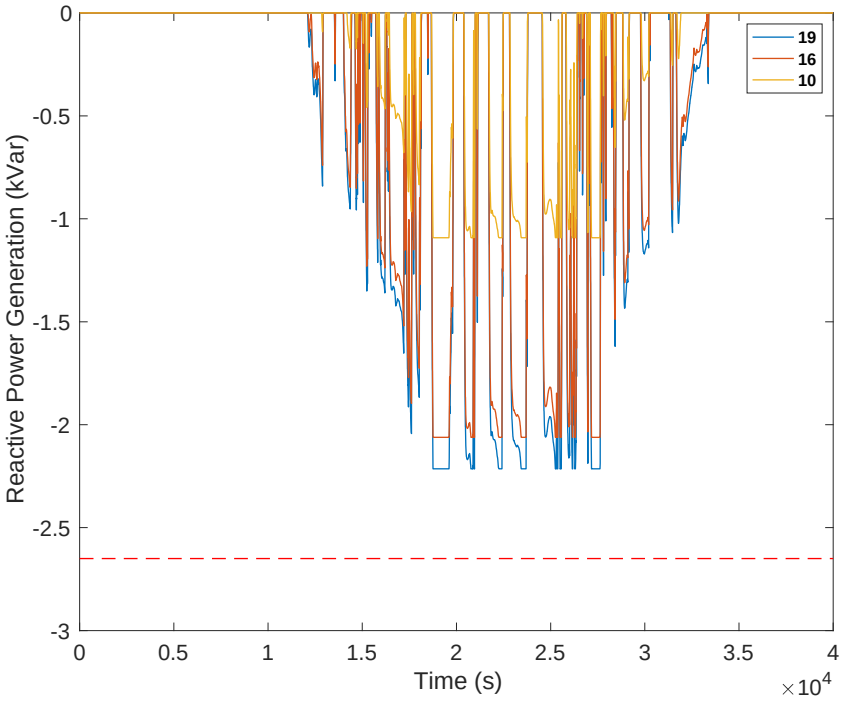

Figure 15 Amount of reactive power at PV systems with (Q(V)) control.

Figure 16 shows the active power losses in the main lines when the PV systems at bus 16 and 19 support reactive power control, respectively. Moreover, the active power losses comparison between two cases are given in Figure 17.

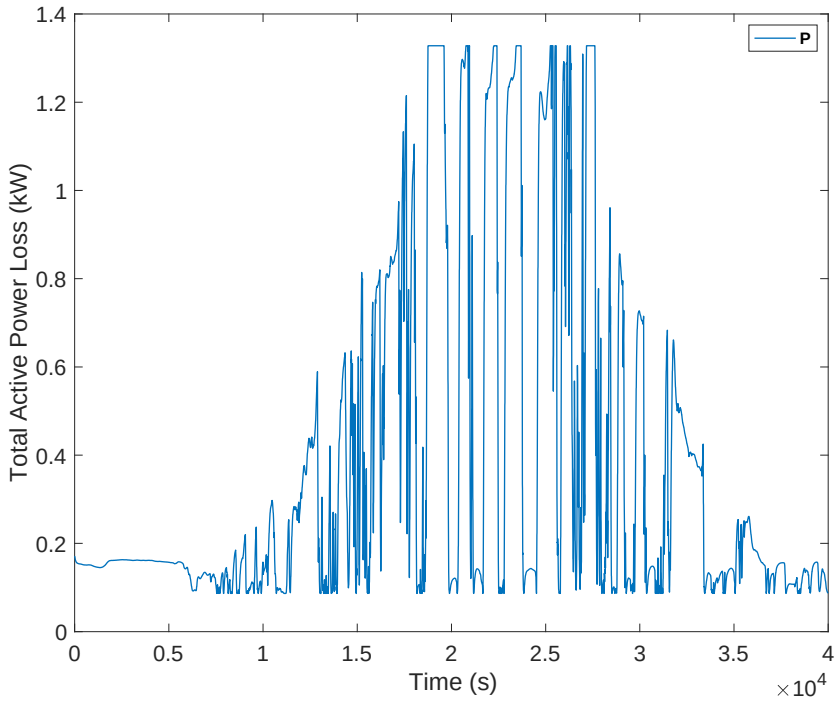

Figure 16 Amount of active power loss with (Q(V)) control at main lines.

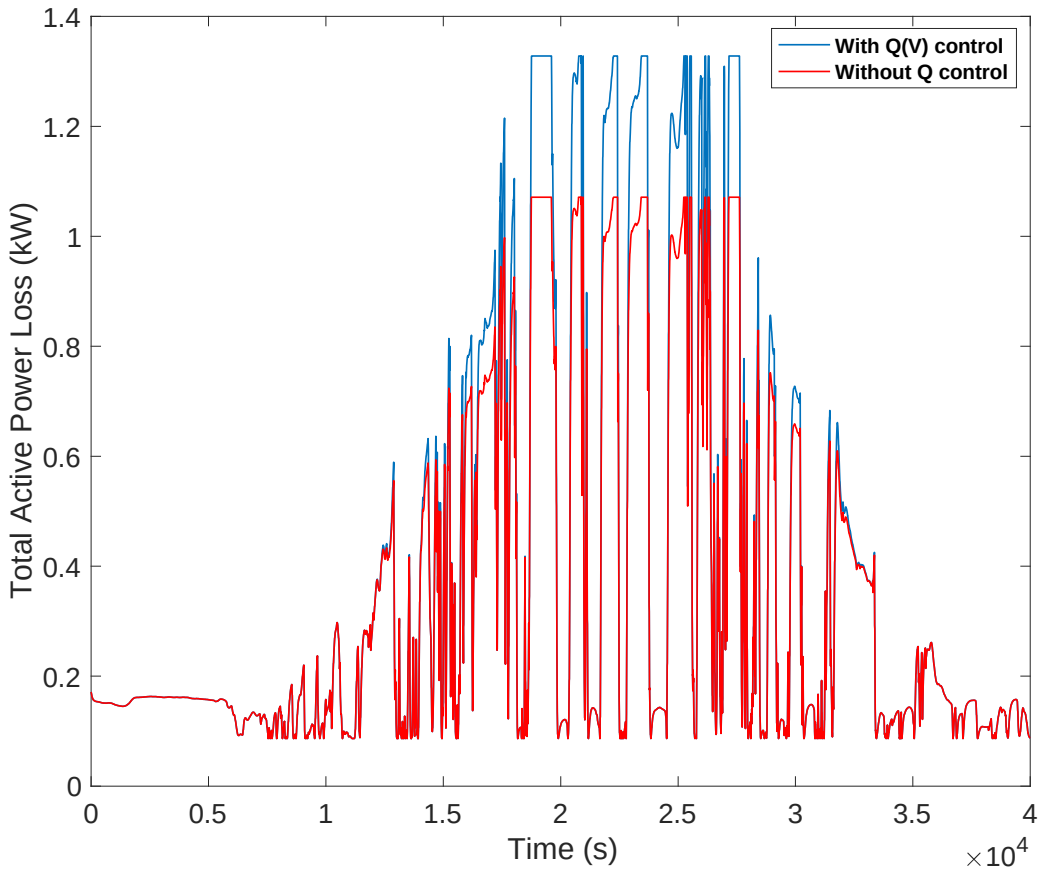

Figure 17 Comparison of active power loss with two methods.

4 Data Flow and Actuation

As described earlier, the coordination control takes place in the Automated Voltage Regulation (AVR) app. This chapter describes how the AVR app fits within the larger Net2DG framework, as well as what actuation capabilities can potentially be exploited to achieve better voltage quality.

4.1 Interaction with Observability Grid Model

The AVR app is located in the Application layer of the Net2DG architecture, as shown in Figure 18. It communicates primarily with the Observability Grid Model (OGM) to obtain detailed grid information, as well as with the field equipment via the ICT Gateway Service layer in order to obtain close-to-real-time measurements and transmit set-points to inverters.

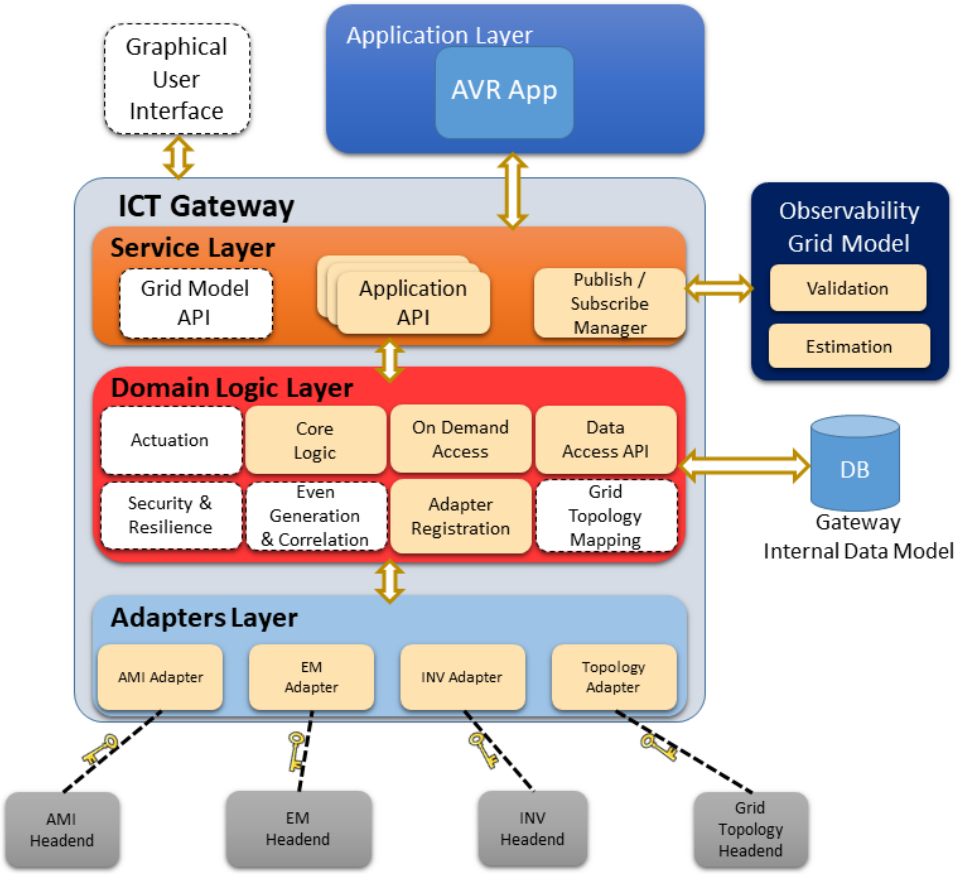

Figure 18 AVR application's location in the Net2DG architecture

4.2 Data flow and aggregation of measurements

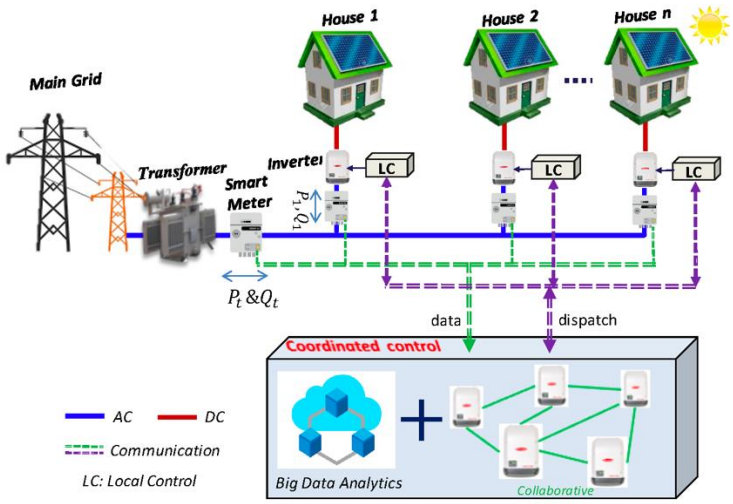

Figure 19 Coordinated control in low voltage distribution grid.

Figure 19 shows the basic data flow in the coordination control scenario. Local smart meters (AMI) measure busbar voltages, averaging over suitable intervals – e.g., 15 minutes – and submit these to the ICT Gateway. The data is aggregated and reflected in the Gateway Internal Data Model. The overvoltage situation is detected and the AVR app is notified. It requests detailed grid parameters from the Observability Grid Model (OGM) as well as the most recent voltage and power measurements (V_i, P_i, Q_i) from the inverters along the feeder. The AVR app computes a feasible solution to the coordination control problem (see the following chapter) and dispatches correction signals to the inverters along the feeder. The input and output signals of the coordination control is summarised in the Table 4.1.

Table 4.1 Input and output signals of the coordination control

Input signal	Name	Unit	Frequency	Source
Sensitivity matrix	S_i	V/VAr	10 min	OGM
Reactive power of PV	Q_i	VAr	10 min	Inverter
Voltage of PV	V_i	V	10 min	Inverter

Output signal	Name	Unit	Frequency	Destination
Voltage setpoint set for each PV	$[V_1, V_2, V_3, V_4]_i$	pu	10 min	Inverter
Reactive power setpoint set for each PV	$[Q_1, Q_2, Q_3, Q_4]_i$	pu	10 min	Inverter

4.3 Actuation capabilities

PV inverters offer various actuation capabilities that may or may not be exploited by a given coordination control scheme. The most important ones are listed in the following.

4.3.1 Common reactive power control methods

In order to reduce the grid voltage, one might decrease the active power by reducing the overall energy generated by the PV system; however, doing so incurs a loss to the asset operator. An alternative approach is to control the reactive power of the inverter. The downside of this is that the total current fed into the grid will increase, leading to higher losses.

In general, reactive power control methods focusing on 10-min average voltage variations can be divided into following main categories, as follows:

- *Constant* cos *φ mode*: Constant specification of cos *φ*. An example of this is illustrated in Figure 20.
- *Voltage-dependent reactive power mode Q(V)*: Specification of relative reactive power depending on grid voltage. An example of this is illustrated in Figure 21.
- *Active power-dependent reactive power mode Q(P)*: Specification of relative reactive power depending on active power generation; see Figure 22.
- *Constant reactive power mode*: Constant specification to relative reactive power in % relative to the nominal apparent power of the inverter; see Figure 23.
- *Active power-dependent* cos *φ*: Specification of cos *φ* depending on effective power

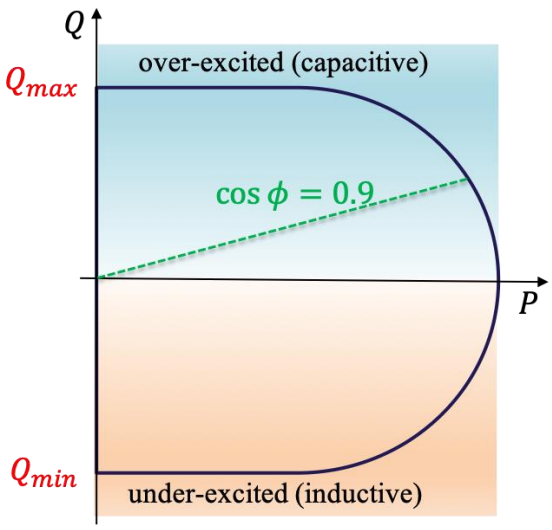

Figure 20 Constant cos *φ* mode

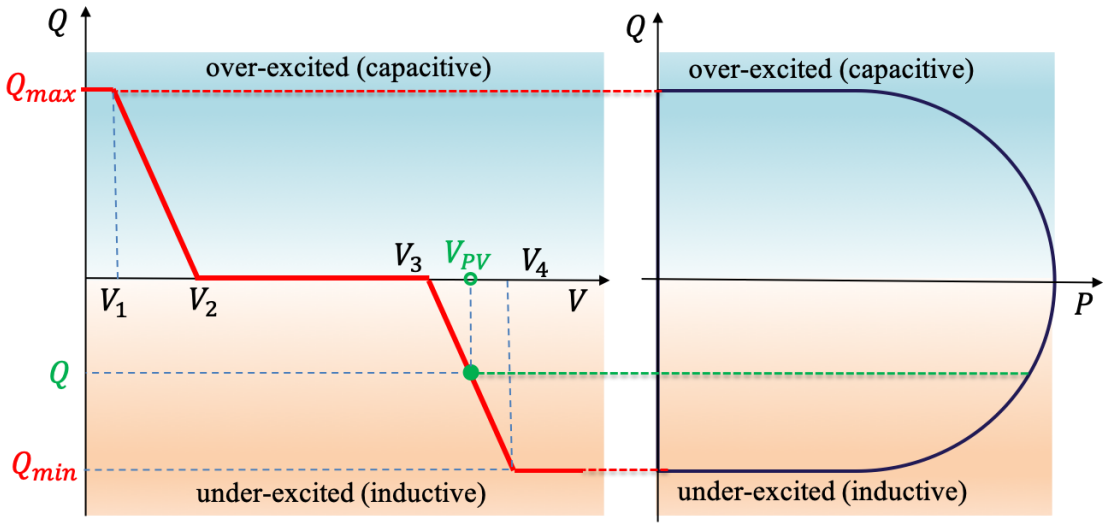

Figure 21 Voltage-reactive power mode *Q(V)*

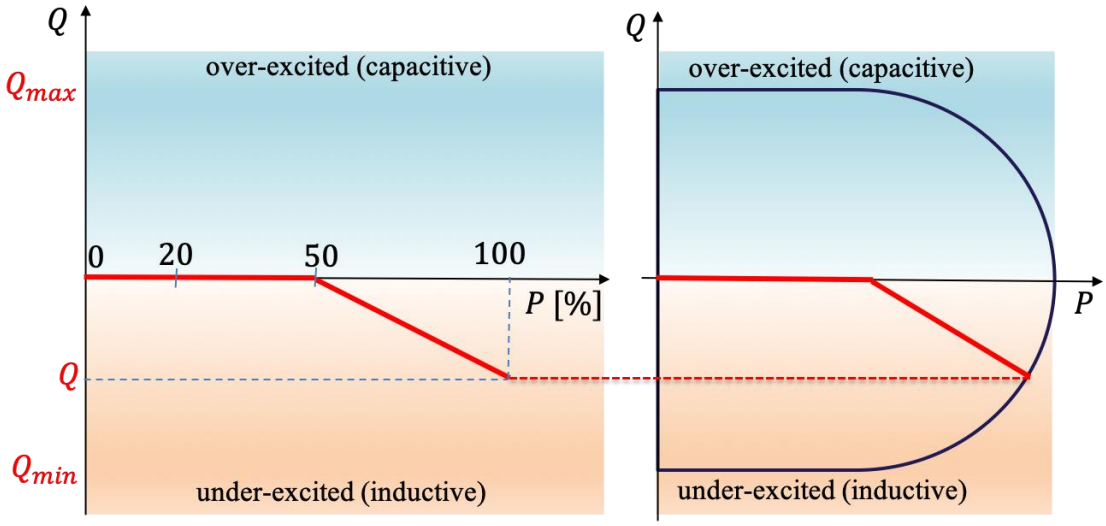

Figure 22 Active power-reactive power mode *Q(P)*

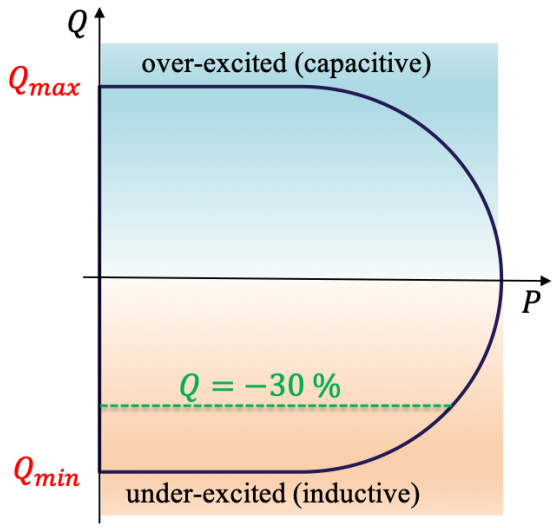

Figure 23 Constant reactive power mode

4.3.2 Reactive power control capabilities of state of the art inverter

The following options for switching reactive power modes and for controlling the inverter are available [7]:

- *Const.* cos *φ*: Constant specification of cos ϕ
- *Const. Q Rel*: Constant specification for relative reactive power in % relative to the nominal apparent power of the inverter
- *Const. Q Abs*: Constant specification of absolute reactive power in VAR
- cos *φ*(*P*): Specification of the cos ϕ depending on effective power P
- *Q* (*V*): Specification of relative reactive power depending on grid voltage
- *Q* (*P*): Specification of relative reactive power depending on effective power

4.3.3 Voltage-depending active power curtailment

Although the voltage-active power mode control is more effective in terms of voltage support than reactive power injection in the low voltage distribution grid, the revenue of each PV asset operator is decreased. If enabled, the voltage-depending active power reduction *P(V)* shall remain active while any of the voltage-reactive power modes described above are enabled. As shown in Figure 24, the voltage is still smaller than V_1 (e.g., 1.1 pu), then the PV inverter generates its maximum active power. However, when the voltage is larger than V_1, the PV inverter is forced to gradually decrease its active power generation. Once the voltage increases to V_2 (e.g., 1.13 pu), the PV inverter operates at zero active power.

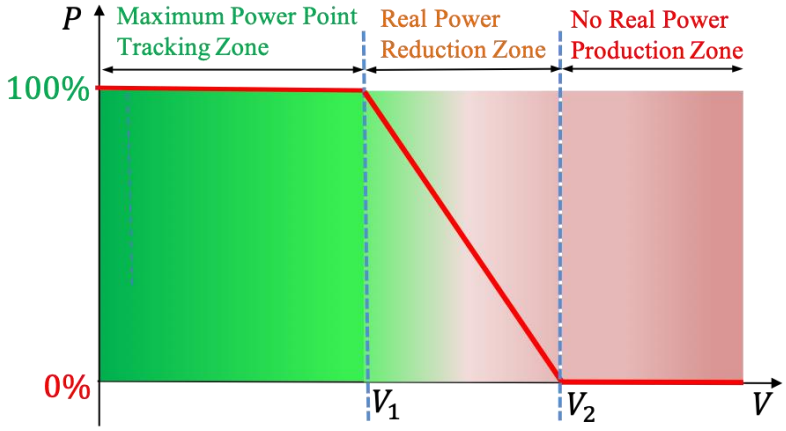

Figure 24 Voltage-active power control curve in the local control of real power

5 Coordination control design

With the grid simulation framework and local control in place, this chapter describes the coordination control design. As outlined above, the goal of the coordination control scheme is to compute reconfiguration of the local control parameters of PV inverters to bring the voltage within bounds in case of an overvoltage situation. That is, in the case of an overvoltage situation, a correction Q_{cor} calculated from the centralized controller is sent to each local PV inverter to shift the $Q(V)$ droop in the local controller, which then reacts accordingly.

5.1 Basic coordination control

The coordination control calculates the optimal set points to each local controller at each sampling instance (i.e., at sampling time *kT*), based on measurements obtained from the field (see Figure 25). For example, since the voltage is averaged every 10 minutes, the coordination control loop will also be executed and signals sent to each PV system every 10 minutes. The local control will receive a correction to the reactive power and calculate its new $Q(V)$ control.

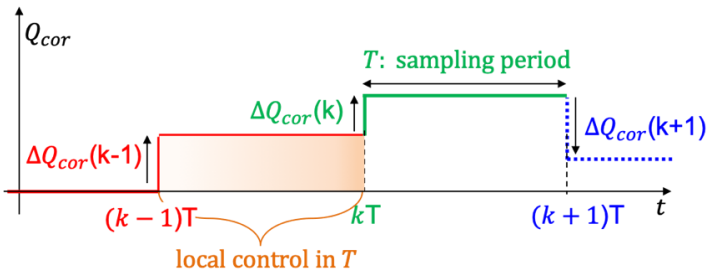

Figure 25: Reactive power corrections received from the coordination controller.

To solve the coordination control problem, the following inputs are required at each sampling instance:

- Sensitivity matrix of each PV, which relates tp how much the bus voltages change after a small change ΔQ
- Averaged voltages on each busbar with PV connected
- Measured reactive power generation of each PV
- Previous calculated optimal results

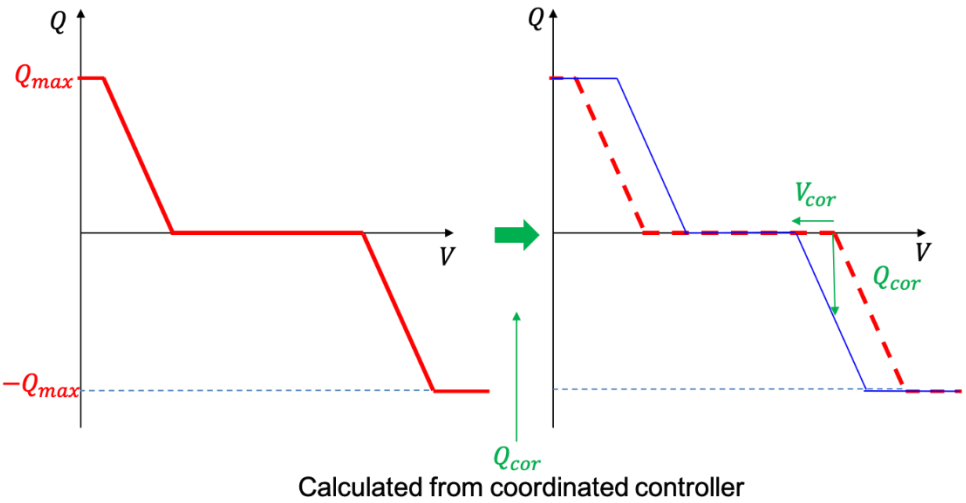

Figure 26 $\boldsymbol{Q(V)}$ shifting by $\boldsymbol{Q_{cor}}$ sent from coordination control.

Based on the aforementioned inputs, the coordination control computes a set of corrections ΔQ_{cor} to be issued to each of the relevant inverters, where the original $Q(V)$ is corrected by adjusting the voltage deadband, as shown in Figure 26.

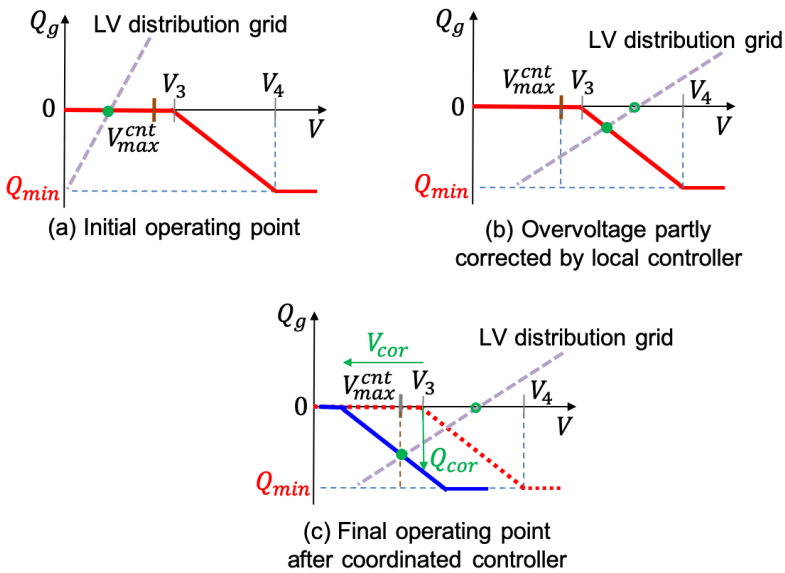

Figure 27 Example of over-voltage correction by local and centralized controls (only high voltage part of the characteristic is shown). The smaller slope of the VQ curve in sub-figures 3(a) and 3(b) compared to 3(c) corresponds to a larger Thevenin impedance seen by the PV inverters. **[8]**

Figure 27 shows an over-voltage situation and the subsequent actions at both levels to remove the violation. The initial operating point of the PV inverter, shown with a green dot, is at the intersection of the PV inverter and LV distribution grid Q(V) characteristics. In the example of Figure 27(a), the voltage lies in the dead-band; therefore, initially, the inverter operates at unity power factor. Under

the effect of a disturbance, the LV distribution grid characteristic changes and the inverter terminal voltage exceeds the upper limit $\mathrm{V}_{\mathrm{max1}}^{\mathrm{loc}}$. The green circle in Figure 27(b) shows the situation with no control. Although the violation is partly corrected by a first and fast reaction of the local controller (green dot in Figure 27Figure 26(b)), the voltage is still above the upper voltage limit $\mathrm{V}_{\mathrm{max}}^{\mathrm{cnt}}$ monitored by the coordinated controller. The latter computes a sequence of corrections $\Delta\mathrm{Q}_{\mathrm{cor}}$ and sends them to the local controller. Then, it will shift $\mathrm{Q}(\mathrm{V})$ characteristic as shown in Figure 27(c). [8]

Assuming operation on the same sloping part of the $Q(V)$ profile, the voltage shift V_{cor} corresponding to a given value of Q_{cor} is:

$$V_{cor} = \frac{Q_{cor}}{\ell} \tag{1}$$

where ℓ is the local droop of $Q(V)$.

The equation of the solid black line is:

$$Q - Q_{cor} = -\ell(V - V_{max}^{loc}) \tag{2}$$

involving the already defined droop ℓ. Considering small deviations denoted with Δ, Eq. (2) may be rewritten as

$$\Delta Q - \Delta Q_{cor} = -\ell\, \Delta V \tag{3}$$

The variations of bus voltages as a function of the inverter reactive powers are given by:

$$\Delta V = S_{VQ} \Delta Q \tag{4}$$

where S_{VQ} can be obtained from the transposed inverse of the power flow Jacobian matrix.

At sample number k, an *objective function* is formulated to minimize the deviations of the inverter reactive powers, $Q(k+i)$, from their measured values, $Q_m(k)$ over the next N_c steps:

$$\min_{Q,V,\varepsilon,\Delta Q,\Delta Q_{cor}} \sum_{i=0}^{N_c-1} \|\Delta Q(k+i)\|_{W_Q}^2 + \|\varepsilon\|_S^2 \tag{5}$$

The following *inequality constraints* are imposed:

$$\varepsilon = [\varepsilon_1, \varepsilon_2]^T \geq 0 \tag{6}$$

For i= $1, \cdots, N_p$:

$$\left(-\varepsilon_1 + V_{min}^{cut}\right)\mathbf{1} \leq \boldsymbol{V}(k+i) \leq \left(V_{max}^{cut} + \varepsilon_2\right)\mathbf{1} \tag{7}$$

$$I(k+i) \leq I_{max} \tag{8}$$

For $i = 0, \cdots, N_c - 1$:

$$Q_{min}(k) \leq Q(k+i) \leq Q_{max}(k) \tag{9}$$

$$\Delta Q_{min}(k) \leq Q(k+i) - Q(k+i-1) \leq \Delta Q_{max}(k) \tag{10}$$

where $\mathbf{1}$ denotes a vector of unit entries, Q_{min}, Q_{max}, ΔQ_{min} and ΔQ_{max} are the lower and upper limits on inverter reactive powers and on their rates of change. In (10), $Q(k+i-1)$ is set to $Q_m(k)$. In (5), the difference reactive power can be defined as follows:

$$\Delta Q(k+i) = Q(k+i) - Q_m(k) \tag{11}$$

And W_Q is a diagonal matrix allowing to give different weights to different inverters. The second term in (5) involves the slack variables ε aimed at relaxing the inequality constraints in the case of infeasibility. Matrix S is also diagonal with large diagonal elements to force the constraints. The quadratic (L_2) norm in (5) tends to spread the whole control effort over a larger number of inverters among those that can help correcting the voltage problem.
The minimization is subject to the approximated linearized relation between ΔQ and the control variables, ΔQ_{cor}, $(i = 0, \cdots, N_c - 1)$:

$$\Delta Q(k+i) = S_{QQ} \Delta Q_{cor}(k+i) \tag{12}$$

where S_{QQ} is the coefficient related to the sensitivity matrix, and it will be discussed later. The linearized predicted evolution of voltages over the future N_p steps $(i = 1, \cdots, N_p)$:

$$V(k+i) = V_m(k) + S_{VQ} \Delta Q(k+i-1) \tag{13}$$

$$I(k+i) = I_m(k) + S_{IQ} \Delta Q(k+i-1) \tag{14}$$

where $V(k+i)$ and $I(k+i)$ are the vector of predicted bus voltages and branch currents at time $k+1$, respectively. The prediction is initialized with the last gathered measurements $V_m(k)$ and $I_m(k)$. S_{VQ} is sensitivity matrix, and S_{IQ} relates the branch current variation to inverter reactive power changes. The use of the static transition model (13) and (14) is justified by the fast response of the power electronics compared to the MPC sampling time. [8]

Alternatively, each column of the matrix can be computed by running a power flow calculation with one inverter reactive power slightly modified, and dividing the bus voltage variations by the reactive power variation considered. Substituting (4) in (3) results in

$$\Delta Q = \left(1 + \ell S_{VQ}\right)^{-1} \Delta Q_{cor} \tag{15}$$

The sought matrix is thus given by:

$$S_{QQ} = \left(1 + \ell S_{VQ}\right)^{-1} \tag{16}$$

The above calculation is made under the assumption that all PV inverters operate on the sloping portion of their $Q(V)$ characteristics.

It should be noted that different voltage limits are set in the local and coordinated controls. The local control aims at mitigating the voltage excursion in the very first seconds after a disturbance.
The coordinated control activates only if the terminal voltage exceeds the limit $\mathrm{V}_{\max}^{\mathrm{cnt}}$. This is the case if $\mathrm{V}_{\max}^{\mathrm{cnt}} < \mathrm{V}_{\max 1}^{\mathrm{loc}}$. [8]

5.2 Weighted coordination control

The above calculation is made under the implicit assumption that all PV inverters operate on the sloping portion of their $Q(V)$ characteristics. At sample number k, the objective function is re-formulated to minimize the deviations of the n-th inverters reactive powers, $Q(k+i)$, from their last measured values, $Q_m(k)$ over the next N_c steps:

$$\min_{Q,V,\varepsilon,\Delta Q,\Delta Q_{cor}} \sum_{j=1}^{n} \sum_{i=0}^{N_c-1} \left\|\Delta Q_j(k+i)\right\|_{W_Q}^2 + \|\varepsilon\|_S^2 \tag{17}$$

where $\left\|\Delta Q_j(k+i)\right\|_{W_Q}^2 = \Delta Q_j(k+i)^T\, W_Q \Delta Q_j(k+i)$ and

$$W_Q = \begin{bmatrix} \sum_{j=1}^{n} S_{VQ,1-j} & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & \sum_{j=1}^{n} S_{VQ,n-j} \end{bmatrix} \tag{18}$$

as well as the approximated linearized predicted evolution of voltages over the future N_p steps ($i = 1, \cdots, N_p$):

$$V_l(k+i) = V_{m,l}(k) + \sum_{j=1}^{n} S_{VQ,l-j}\, \Delta Q_j(k+i-1) \text{ for } \forall l = 1, \dots, n, \tag{19}$$

For the constraints, we added more slack variables for each inverter.

$$\varepsilon = [\varepsilon_1, \dots, \varepsilon_n]^T \geq 0 \tag{20}$$

For $i = 1, \cdots, N_p$

$$-\varepsilon_j + V_{min}^{cut} \leq \boldsymbol{V_j}(k+i) \leq V_{max}^{cut} + \varepsilon_j, \text{ for } \forall j = 1, \dots, n, \tag{21}$$

Notice that the weighting factors of ε should be larger compared with $\Delta Q_j(k+i)$.
A block diagram showing how the coordination control is connected to the simulation model discussed in the previous section can be seen in Figure 28. The optimization problem described above is implemented in the system block labelled “Coordinated Control” and solved by calling

MATLAB's **Quadprog** solver (found in the **Optimization** toolbox). See Section 7.1 for a more detailed description of the overall implementation.

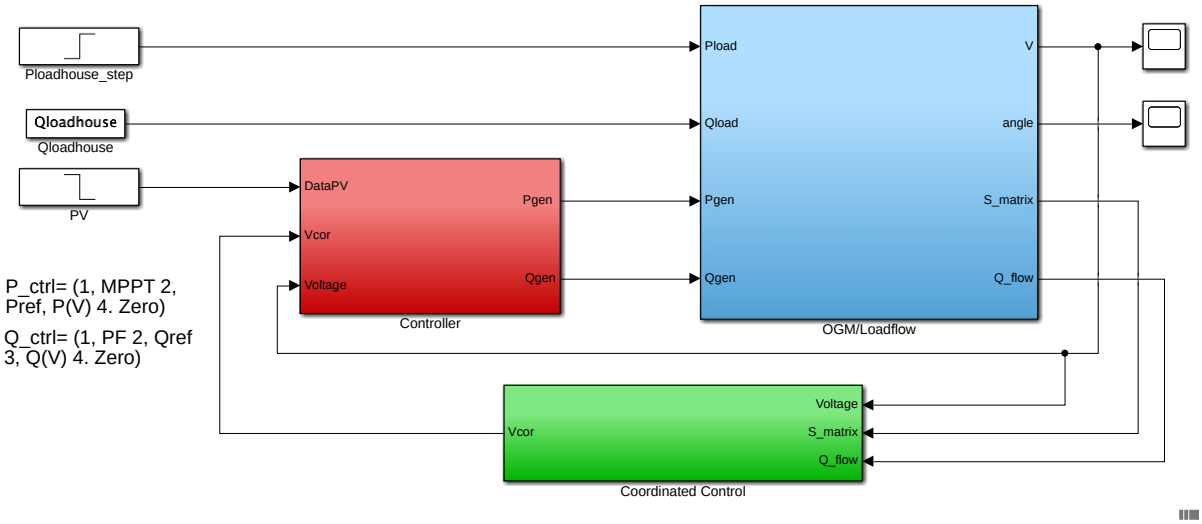

Figure 28 Simulation model implemented in MATLAB/Simulink.

5.3 Simulation studies

A benchmark test scenario is applied to account for the operational points of PV systems at their MPP as 5 kW. For the sake of the simplicity, it is assumed that the sampling time of the coordination control is 20 s. That is, it is assumed that the active power is constant throughout each 20-second interval, and that correction signals of the form $V_{cor} = Q_{cor}/\ell$ are issued every 20 seconds.

The local $Q(V)$ control parameters of the PV inverter are set as follows:
$V_1 = 0.9$ pu, $V_2 = 0.95$ pu, $V_3 = 1.05$ pu, and $V_4 = 1.1$ pu.
Furthermore, $Q_{max} = 0.53$ pu and $V_{max}^{cnt} = 1.045$ pu.

Conditions:

Ploadhouse	0.550 kW	Load (active power) of each house
Qloadhouse	0 Var	Load (reactive power) of each house
Rated of PgenPV	5 kW	Rated generation of PV system
Reactive power control	$Q(V)$	Function of V
Ctrl_act	20 s	Coordinated control active time

5.3.1 Basic coordination control

Figure 29 shows the voltages on each bus as a function of simulation time.

In this case, the PV systems inject the rated active powers to the grid with their local *Q*(*V*) method for the first 40 s. At first, the PV inverters at branch bus 16 and 19 provide reactive power support to the grid since their voltages are above the 1.05 pu, which activates the local *Q*(*V*) control of the PVs at branch bus 16 and 19.

After 40 s, the coordinated control is activated and starts sending corrections to each of the PV inverters. Since the voltages at branch bus 16 and 19 are above 1.045 pu, the centralized controller calculates their corrections to the corresponding inverters. However, the voltage at branch bus 10 is below 1.035 pu the whole time as shown in Figure 30, which means that it no reactive power is generated by the inverter at branch bus 10, as shown in Figure 31, in this case.

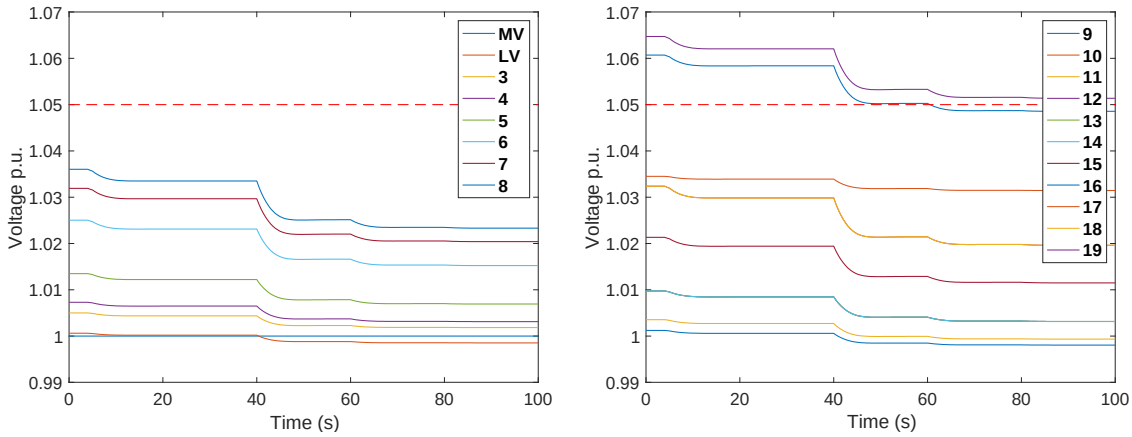

Figure 29 Main bus voltages (left) and each branch bus voltages (right) with basic coordination control.

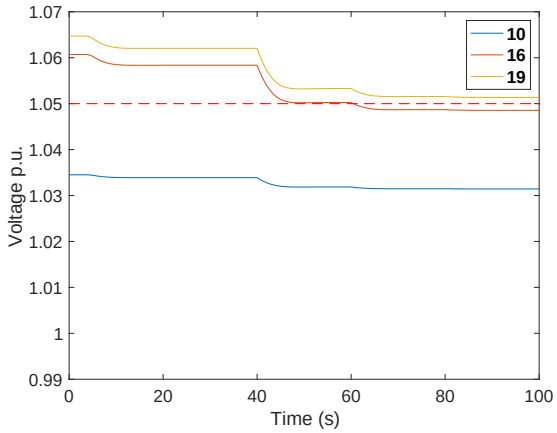

Figure 30 Bus 10, 16, and 19 voltages with basic coordination control.

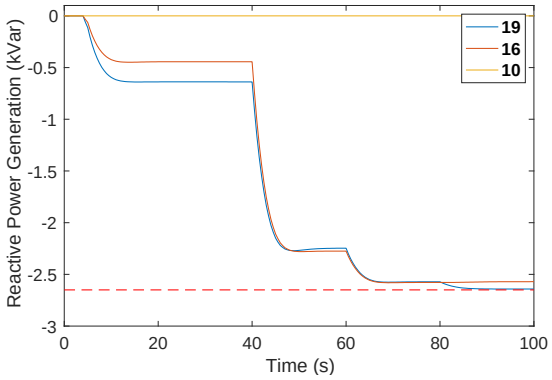

Figure 31 Amount of reactive power generated by PV systems with basic coordination control.

5.3.2 Weighted coordination control

In the previous case, the PV system at the bus 10 did not support reactive power since the local voltage was remaining within the limits. However, the PV system at bus 10 also contributes to the voltage violation effect on the voltage at bus 19, which is still above 1.05 pu. The weighted coordination control is able to cope with this, as may be seen from the simulation shown in from Figure 32 to Figure 34.

After 40 s, the inverter at bus 10 continues to support the voltage by injecting reactive power until voltage on bus 19 decreases below 1.05 pu. Of course, the total reactive power generation is increased.

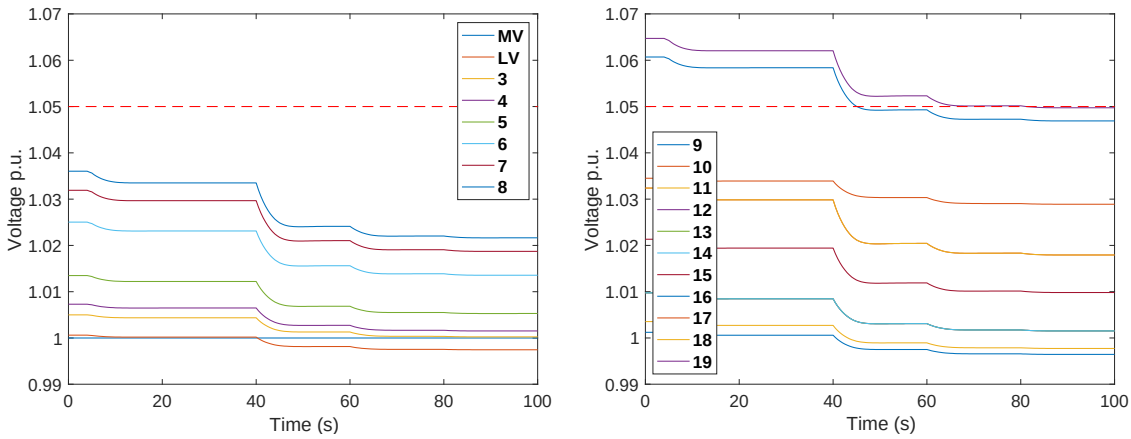

Figure 32 Main bus voltages (top) and each branch bus voltages (bottom) with the weighted coordination control scheme.

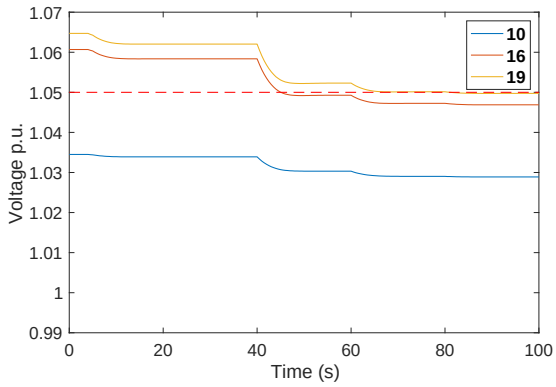

Figure 33 Bus 10, 16, and 19 voltages with the weighted coordination control scheme.

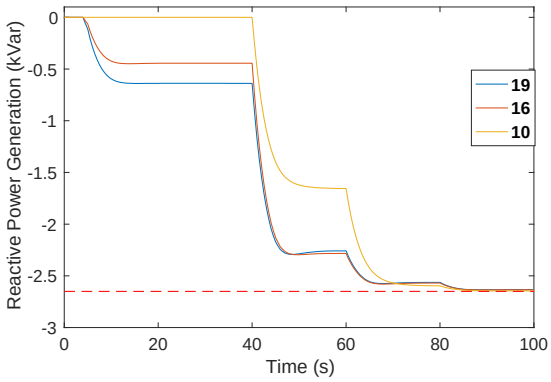

Figure 34 Amount of reactive power injected by PV systems with the weighted coordination control scheme.

6 Guidelines for Implementation in Net2DG architecture

6.1 *Implementation in MATLAB/Simulink*

The initial implementation of the simulation model was made in MATLAB/Simulink at AAU. A brief overview is given here.

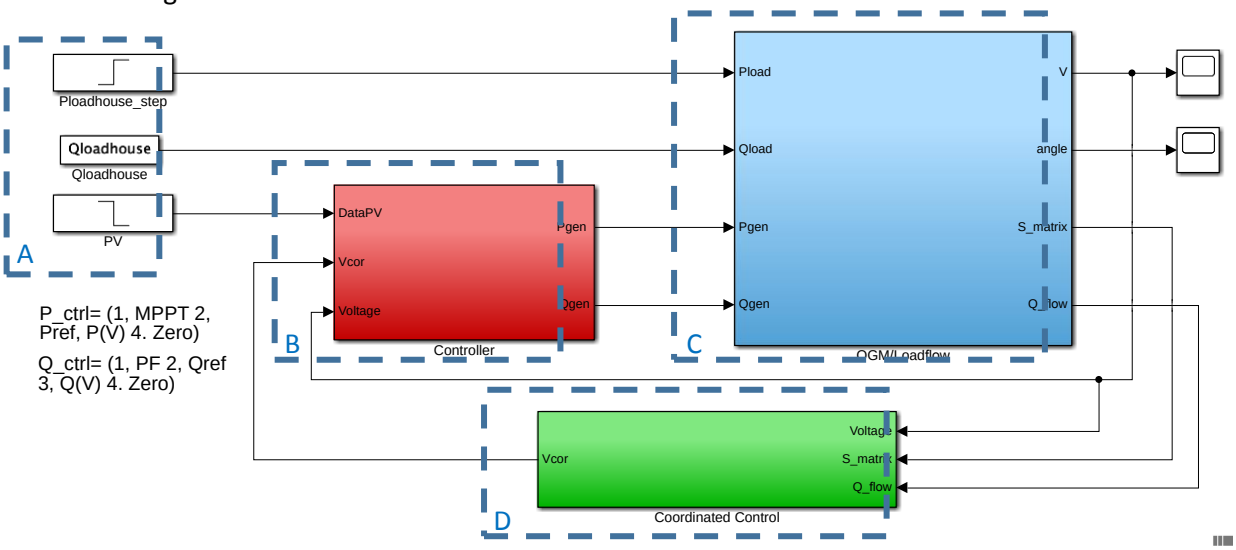

Figure 35 Simulation model implemented in MATLAB/Simulink.

Description:

A	References/Conditions	**Output**: 1. Active power (P) references of each house 2. Reactive power (Q) references of each house 3. Irradiance data of PV
B	local controllers	**Input**: 1. Irradiance data of PV, 2. Voltages at each bus, 3. Correction of voltage from coordinated control **Output**: 1. Active power (P) generations of each PV 2. Reactive power (Q) generations of each PV
C	OGM/Load flow	**Input**: 1. Active power (P) references of each house 2. Reactive power (Q) references of each house 3. Active power (P) generations of each PV 4. Reactive power (Q) generations of each PV **Output**: 1. Voltages at each bus 2. Power angles at each bus

		3. Sensitivity matrix 4. Reactive power flow
D	Coordinated controller	**Input**: 1. Voltages at each PV 2. Reactive power (Q) generation of each PV 3. Sensitivity matrix 4. Reactive power flow at each PV **Output**: **1.** Voltage corrections for each PV

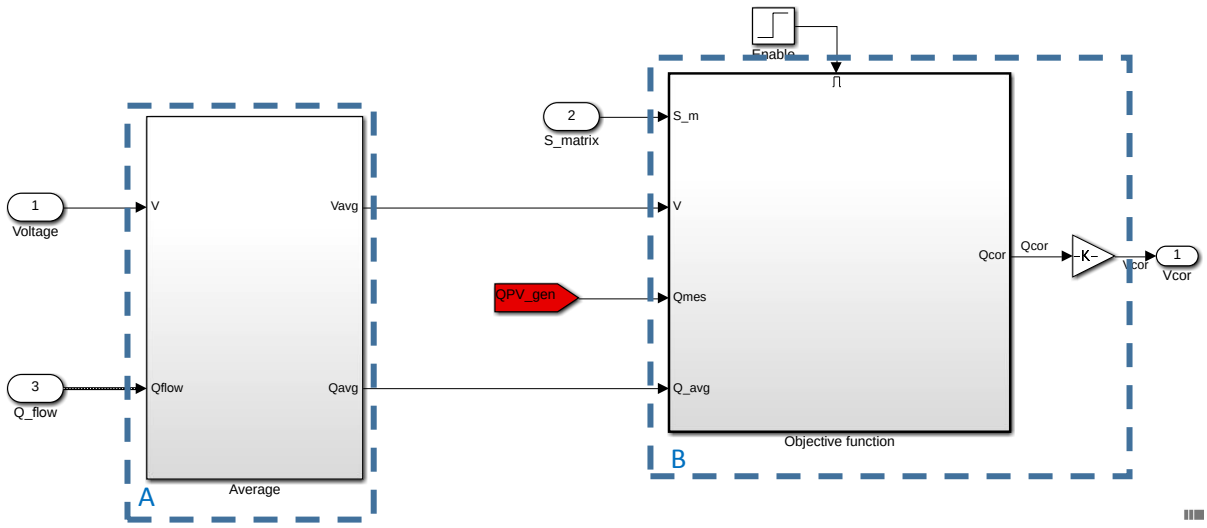

Figure 36 Controller block diagram

Description:

A	Calculate averaged values of voltages and reactive powers for a certain time Tavg.	**Input**: 1. Voltages at each PV 2. Reactive power flow at each PV **Output**: 1. Averaged voltages at each PV 2. Averaged reactive power flows at each PV
B	Objective function to solve the optimal operating point for each PV	**Input**: 1. Sensitivity matrix 2. Averaged voltages at each PV 3. Measured reactive power generation of each PV 4. Averaged reactive power flows at each PV **Output**: 1. Voltage corrections for each PV obtained from reactive power corrections as follows:

		$V_{cor} = \frac{Q_{cor}}{\ell}$

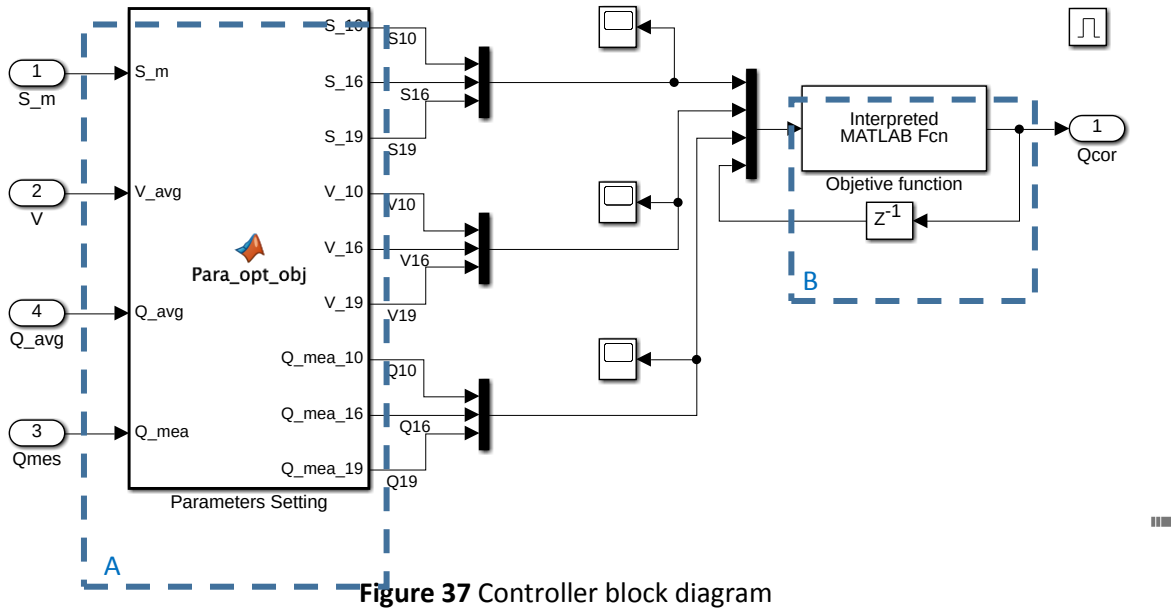

Figure 37 Controller block diagram

Description:

A	Parameters setting for the objective function	**Input**: 1. Sensitivity matrix 2. Averaged voltages at each PV 3. Averaged reactive power flows at each PV 4. Measured reactive power generation of each PV **Output**: 1. Selected sensitivity matrix related to each PV: 2. Selected averaged voltages at each PV 3. Selected measured reactive power generation of each PV
B	Objective function to solve the optimal operating points for each PV	**Input**: 1. Selected sensitivity matrix related to each PV: 2. Selected averaged voltages at each PV 3. Selected measured reactive power generation of each PV 4. Previous output **Output**: **1.** Optimal correction of reactive powers for each PV

6.2 Implementation in Net2DG app

The Simulink block diagram shown in of Figure 37 was re-implemented in Java to serve as Release 1 of the AVR app. To this end, classes with the responsibility of computing the grid sensitivity matrix S and solving the coordination control problem (17) have been implemented. MATLAB code for computing the grid sensitivity matrix can be seen in the code repository. To solve the coordination control problem, a simple Quadratic Program Solver class was implemented using off-the-shelf techniques. It basically adheres to MATLAB's 'quadprog' function interface and yields similar results.

7 Fault scenarios

This chapter briefly considers some potential system faults that might interrupt or otherwise affect the coordination control flow, if they occur.

7.1 Communication failure

Various communication failures may occur, and not all of them are possible to deal with. In order to initiate the coordination control procedure, for example, it is necessary for the field equipment to be able to communicate that an overvoltage situation is present.

Instead we consider a situation where one of the local controllers (PV inverters) cannot receive the correction command from the coordinated control, i.e., that PV system only works with the standard local control. Specifically, it is assumed that the PV system at bus 10 cannot receive the correction signal from the coordination control. It can be observed from the voltage traces in Figure 38 that this lack of communication results in voltage profiles similar to the ones in the basic coordinated control, as shown in Figure 30 and Figure 31. In both cases, the PV system at bus 10 does not support reactive power to the grid, since the voltage at bus 10 is in the limit. If the PV system at bus 19 instead cannot receive the signal from the coordinated control, then both voltages at bus 16 and 19 are larger than 1.05 pu, as shown in Figure 39.

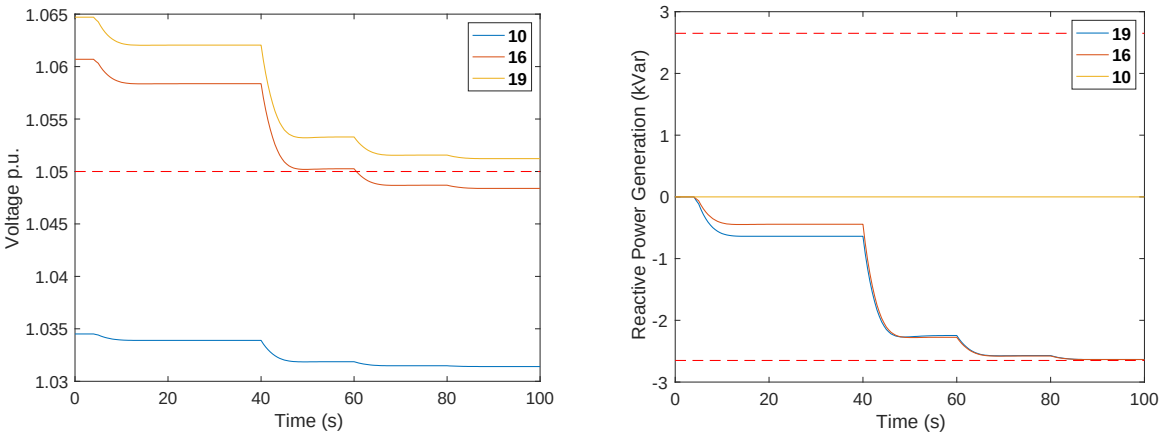

Figure 38 Bus 10, 16, and 19 voltages (left) and amount of reactive power at PV systems (right) with the proposed reactive power control with PV system when the PV at 10 bus receives no signal from coordinated control.

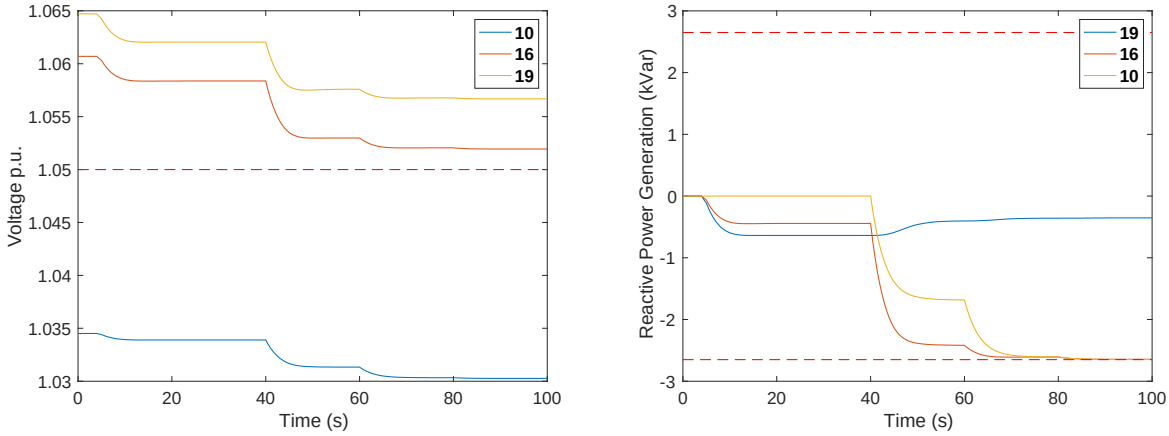

Figure 39 Bus 10, 16, and 19 voltages (left) and amount of reactive power at PV systems (right) with the proposed reactive power control with PV system when the PV at 19 bus receives no signal from coordinated control.

In the case of loss of communication from the Net2DG Gateway server to the local PV systems, the inverter control automatically falls back to a safe default set of setpoints. In addition, if Q(V) control coordination fails and there is a fall-back to a safe default Q(V), there is two additional failsafe levels: 1. P(V) control cuts into active power if the voltage is getting close to the voltage trip limit; 2. The autonomous interface protection disconnects the inverter from the grid if the upper voltage limit is about to be violated. Reconnection after a defined monitoring time.

7.2 Other failures

The coordination control problem is a convex optimization problem, so it is always possible to find a solution as long as the constraints permit a non-empty feasible set. Nonetheless, numerical issues may cause the problem to be difficult to solve in practice. In such cases, the optimization fails, and the coordination control is unable to find suitable correction signals. The introduction of so-called slack variables in the problem ($\mathcal{E}$ in Equation (17)) should mitigate this issue, but if it persists, the AVR app fails and an alarm shall be raised to the operator in this case.

8 Findings and Recommendations

This chapter provides a brief summary of the findings and recommendations for future work at the stage of completion of Deliverable 4.1.

8.1 Findings

The following main tasks were completed:

- A low voltage grid radial from the TME field study is selected as a representative test case. A grid model of this radial developed in Work Package 2 was adopted and modified for the present study to highlight a potential over-voltage situation.
- An optimization-based coordination control scheme was formulated, and it was demonstrated that the problem could be solved and correction signals to the local controllers could be generated to cause the voltage along the radial to converge to within the permitted bounds.
- The initial MATLAB/Simulink simulations were followed up by a Java app to be included in the Net2DG framework.
- A few potential fault scenarios were discussed. In particular, a communication failure between the Net2DG gateway server and one of the PV systems in the field was simulated. It was found that the coordination could be failed by such a failure.

The main goals set for Release 1 were thus achieved.

8.2 Recommendations

Only simplified coordination control is achieved in this release. Future work involves:

- Considering different correction signals. Modern inverters possess control modes other than simply adjusting the voltage deadband, which may yield better coordination control performance. It may furthermore be relevant to consider active power control as well, i.e., $P(V)$.
- Considering scenarios 2 and 3. The scenario considered in the present document is simpler than the other two, but more relevant to the present-day situation in most real-life low voltage distribution grids. The inclusion of storage and considering power flow across the local MV/LV transformer would be of interest to DSOs who are planning future installations of energy storage systems on the LV distribution grid.
- Studying problem complexity and scalability. The radial considered in this report is very simple; it would be interesting to investigate radials with PV distributed several branches. Furthermore, the associated optimization problem is easy to solve due to a low number of PV installations. However, it is known that increasing the number of decision variables causes the optimization problem to become much harder to solve; the rate at which the complexity of the involved algorithms grow, should be investigated.

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