An enhanced role for an energy storage system in a microgrid with converter-interfaced sources

Konstantinos O. Oureilidis, Charis S. Demoulias

Department of Electrical and Computer Engineering, Aristotle University, Thessaloniki, 54124, Greece
E-mail: chdimoul@auth.gr

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Abstract: An enhanced role for the energy storage system (ESS), strategically placed at the point of common coupling (PCC) of the microgrid with the utility grid, is proposed. During island operation, the ESS ensures that the frequency and magnitude of the voltage will remain within the limits specified by the Standard EN 50160. By implementing an adjustable droop control method, the distributed energy resources (DERs) adjust their active and reactive powers in order to fulfill the load demand. When the grid is recovered, the ESS detects its presence and achieves a seamless synchronisation of the microgrid with the main grid, without any kind of communication. In grid-connected mode, the DERs deliver their available active power, whereas their reactive power is determined by a zero-sequence voltage. This voltage is injected by the ESS and aims to the zeroing of the amount of reactive power at the PCC. In this way, a reduction of power losses in the distribution lines of the microgrid is achieved. The effectiveness of the proposed control method in all operation modes, without any physical communication means, is demonstrated through detailed simulation in a representative microgrid with DERs fed by photovoltaics.

1 Introduction

The increase of grid-connected renewable energy resources has contributed to the upcoming decentralised approach of the power grid, where clusters of microsources and loads form entities called microgrids. The microgrids should operate either connected with the upstream utility network or in island mode, in case of grid unavailability [1]. Each distributed energy resource (DER) is interfaced to the microgrid through DC/AC or AC/DC/AC converters. Consequently, the energy management of the microgrid can be carried out through proper control of the converters. In both grid-connected and island mode, the voltage within the microgrid should always comply with the limits imposed by the EN 50160 Standard [2].

When the island operation condition is identified [3, 4], several DERs share the produced power in order to fulfill the load demands. The power sharing among the DERs can be carried out either using signals via physical communication means [1, 5] or using local voltage measurements as communication parameters [6, 7]. The latter method is also referred to as ‘wireless’ method.

In grid-connected mode, the control strategy of the DERs is adjusted to controllable current sources [8], in order to transfer the available active power to the common AC bus. Regarding the adjustment of the reactive power of the DERs, different methods have been proposed, depending on the existence or not of communication between the DERs. In the ‘wireless’ method, only compensation of the reactive power of local loads or local voltage regulation is performed [6]. On the other hand, in the communication-based method, the reactive power of the DERs can also be adjusted in terms of optimal power flow [9].

Apart from the DERs, the coordination of the microgrid with an energy storage system (ESS) is considered necessary for several reasons [10]. The most important include the reinforcement of the dynamic behaviour [11], the contribution to the seamless transition from grid-connected to island mode [12] and the improvement of the operation during faults or transient situations [13, 14].

In this paper, a converter-dominated microgrid with an ESS strategically placed at the point of common coupling (PCC) of the microgrid with the utility grid is investigated, as shown in Fig. 1. Additionally, it is assumed that there is no physical communication between the DERs and the ESS. The control of the ESS converter performs the following operations: (i) during the synchronisation process, the ESS adjuts the magnitude, phase and frequency of the common AC bus voltage by regulating the active and reactive powers of the microgrid. Contrary to the current practice [8, 15, 16], no communication between the grid and the DERs is necessary. (ii) During the islanded operation of the microgrid, the ESS absorbs the mismatches between the power consumption and production [17]. Furthermore, a variable virtual impedance is introduced in the control of the DERs, so that they always operate at power factor (PF) larger than 0.8, while at the same time the minimisation of the circulating reactive currents among the DERs is achieved. (iii) In grid-connected mode, the ESS regulates the sharing of the reactive power among the DERs in a novel way. Specifically, the ESS injects a 7th harmonic zero-sequence voltage into the microgrid, with a magnitude depending on the amount of the reactive power at the PCC. The aim is to zero the exchange of reactive power at this point. Thus, the reactive power load demand is covered by its own DERs, leading to the reduction of the circulating reactive current, and as a result a reduction of the power losses. Furthermore, if a DER and a load are connected at the same local bus, the priority is to cover the reactive power of the local load.

![Fig. 1 Microgrid simulation model](image-url)
The injection of a zero-sequence voltage was selected in conjunction with a Dy transformer at the PCC, since the infinite zero-sequence impedance of the delta winding will restrict this voltage only in the microgrid side. To avoid any false detection because of the presence of 50 Hz zero-sequence voltage components under unbalanced conditions, the 7th harmonic was finally selected. This harmonic, especially in zero-sequence form, naturally exists only in very small magnitudes, while it can also be easily detected by the DERs. The magnitude of the injected 7th harmonic voltage should comply with the restrictions imposed by [2].

2 Control strategy in island mode

In island operation mode, the active and reactive powers of each DER are produced by the frequency and the magnitude of the voltage of the common AC bus, emulating the synchronous machine operation philosophy. The droop control equations can be summarised as follows

\[
\begin{align*}
\frac{df}{dt} &= f^* - m \cdot P - m_a \frac{dP}{dt} \\
\frac{dV_a}{dt} &= V^* - n \cdot Q - n_d \frac{dQ}{dt}
\end{align*}
\]

where \(f^*, V^*\) are the frequency and magnitude of the output voltage at no load, \(m, n\) are the droop coefficients, \(P, Q\) are the average active and reactive powers and \(m_a, n_d\) are the derivative droop coefficients.

If a DER is a renewable one (e.g. photovoltaic (PV) system), the available active power may vary with the available primary energy source (e.g. solar irradiance). In this case, in order to ensure the system stability and the allocation of the active power of the DERs in proportion to the available power of the primary source, the droop coefficients \(m\) and \(n\) should be accordingly adapted

\[
\begin{align*}
m &= \frac{\Delta f_{\text{max}}}{P_{\text{pot}}} \\
n &= \frac{\Delta V_{\text{max}}}{P_{\text{pot}}}
\end{align*}
\]

where \(\Delta f_{\text{max}}, \Delta V_{\text{max}}\) are the maximum deviations of the frequency and the voltage magnitude according to [2], respectively. The power \(P_{\text{pot}}\) corresponds to the maximum power point (MPP) of the renewable source. When the primary source is a conventional one, \(P_{\text{pot}}\) is equal to the apparent power rating of the respective converter [17].

In the aforementioned droop control method, an adaptive virtual impedance [7, 18] is added, in order to minimise the effects of different apparent impedances at the terminals of each DER. The proposed virtual impedance ensures that each DER operates at PF larger than 0.8. This statement is based on the engineering judgement that the majority of the loads in a microgrid operates in this range of PF. The virtual impedance is determined by

\[
L_v = K_{pv}(0.8 - \text{PF}) + K_i \int (0.8 - \text{PF}) \, dt
\]

where \(L_v\) is the virtual impedance, PF is the measured power factor of the DER and \(K_{pv}, K_i\) are the proportional and integral parameters of the PI controller. The control strategy is illustrated in Fig. 2.

The ESS role in island operation mode is the compensation of the mismatches in the active and reactive between the loads and the DERs, as described in [17]. The state of charge (SoC) of the ESS is defined as

\[
\text{SoC} = \frac{Q_{o} - \int i_d \, dt}{Q_{\text{tot}}}
\]
where \( Q_{i} \) is the initial charge of the battery, \( Q_{tot} \) is the rated charge of the battery and \( I_{t} \) is the output active current of the battery converter. This paper uses a battery as ESS, taking into consideration the limits of the battery current and its rate of change. The ESS control strategy is shown in more detail in block 1 in Fig. 3.

3 Grid detection and synchronisation

The recovery of the main grid is detected by a phase locked loop (PLL) circuit incorporated into the control system of the ESS. This PLL circuit constantly monitors the voltage at the grid side (PLL) circuit incorporated into the control system of the ESS. The recovery of the main grid is detected by a phase locked loop (PLL) circuit incorporated into the control system of the ESS. The recovery of the main grid is detected by a phase locked loop (PLL) circuit incorporated into the control system of the ESS.

The main grid is synchronised with the microgrid voltage. For this reason, the ESS increases the microgrid voltage magnitude, \( V_{mgd} \), to ensure that the voltage waveform at the microgrid side of the switch \( SW \) is in phase with the voltage waveform at the grid side of the switch \( SW \). As the frequency difference between the grid and the microgrid is 0.5 Hz, the required time for synchronising the two voltage waveforms is 100 cycles. Therefore, the aggregated time for synchronisation \( t_{sync} \) is set to 150 cycles. The capacity of the battery \( Q_{sync} \) can be calculated as

\[
Q_{sync} = I_{dref_max} \cdot t_{sync}
\]

The maximum \( I_{dref_max} \) is determined by the maximum possible microgrid load. The reasoning is as follows: in the worst case, where the DERs feed the maximum microgrid load, the microgrid frequency is 49 Hz as determined by the respective droop curves. Then, the battery is discharged in order to increase the microgrid frequency to 51 Hz (assuming, in the worst case, the grid frequency to be 50.5 Hz). Following the droop curves, the DERs will supply zero active power at 51 Hz, while the whole load is covered by the battery converter.

After the synchronisation accomplishment, the DERs detect the utility grid, without using any physical communication. The grid detection method is based on indirectly measuring the microgrid impedance. When the grid is connected, the measured microgrid impedance suddenly reduces. The impedance measurement is based on slightly distorting the injected current of each DER by modifying its control angle \( \theta \), which is calculated by the frequency having any other critical influence on the system. Thus, it could be set to any other larger value.

To implement the synchronisation, the following two conditions should be satisfied

1. \( V_{gd} = V_{mgd} \)
2. \( \theta_{PLL} = \theta_{c} \), where \( \theta_{PLL} \) is extracted from the grid-side PLL and \( \theta_{c} \) is the angle of the microgrid voltage.

To calculate the required battery capacity for achieving the synchronisation, the worst-case scenario should be considered. According to this, the voltage waveform at the microgrid side of PCC is assumed to differ almost 2\( \pi \) rad, compared with the grid-side voltage waveform. As the frequency difference between the microgrid and the grid voltage is 0.5 Hz, the required time for synchronising the two voltage waveforms is 100 cycles. Therefore, the aggregated time for synchronisation \( t_{sync} \) is set to 150 cycles. The capacity of the battery \( Q_{sync} \) can be calculated as

\[
Q_{sync} = I_{dref_max} \cdot t_{sync}
\]

Fig. 3 ESS control strategy: (1) discharge, (2) charge, (3) synchronisation and (4) current control

3 Grid detection and synchronisation

The recovery of the main grid is detected by a phase locked loop (PLL) circuit incorporated into the control system of the ESS. This PLL circuit constantly monitors the voltage at the grid side of the switch \( SW \), shown in Figs. 1 and 3. To connect the microgrid with the utility grid with a seamless transient effect, the microgrid magnitude and frequency should reach the respective values of the grid voltage. For this reason, the ESS increases the microgrid frequency by 0.5 Hz higher than the grid frequency. The value of 0.5 Hz results from the difference in the frequency limits among the grid-connected and island operation mode. The active and reactive powers of the battery converter are adjusted by the direct and quadrature reference currents according to

\[
I_{dref} = K_{pd}(f_{g} + 0.5 - f_{m}) + K_{id}(f_{g} - f_{m}) \ dt
\]

\[
I_{qref} = K_{pq}(V_{gd} - V_{mgd}) + K_{iq}(V_{gd} - V_{mgd}) \ dt
\]

where \( I_{dref} \), \( I_{qref} \) are the direct and quadrature reference currents, \( f_{m} \) is the microgrid frequency, \( V_{gd} \) is the grid voltage magnitude, \( V_{mgd} \) is the microgrid voltage magnitude, \( K_{pd} \), \( K_{id} \) are the proportional and integral parameters of the PI controller, as described in block 3 in Fig. 3. The proportional and integral parameters of the PI controller are designed for the worst case, where the grid frequency has its maximum value of 50.5 Hz and the DERs serve the maximum load in island operation mode with 49 Hz frequency. In this extreme case, it is assumed that the time response of the PI controller does not exceed 1 s (50 cycles). This response time affects the stress imposed on the battery discharge without
The optimum battery charging current is defined by

$$I_{bch} = \frac{P_{pot}}{V_{mgd}}$$

where $P_{pot}$ is the power consumed by the ESS, $V_{mgd}$ is the direct axis voltage component, as shown in Fig. 2.

The price of the ESS is determined by

$$V_{0_rms} = \frac{V_{mgd} \cdot K_{pot} \cdot V_{0_rms}}{2} + K_{ip} \int V_{0_rms} \, dt \quad (12)$$

where $I_{qref}$ is the reference reactive current, $V_{0_rms}$ is the dynamic component of the zero-sequence 7th harmonic voltage, $K_{pot}$, $K_{ip}$ are the proportional and integral parameters of the PI controller. The proportional parameter $K_{pot}$ should be determined in order to ensure that the reactive power of each DER is proportional to its rated apparent power. Therefore it can be calculated as

$$K_{pot} = c \cdot S_{nom} \quad (13)$$

where $c$ is a constant parameter set equal to 0.025 in this paper, while $S_{nom}$ is in kilovolt amperes (kVA). The integral parameter $K_{ip}$ is selected in combination with $K_{pot}$ in order to adjust the injected reactive power to the proper value within ~25 cycles.

The signal for zeroing the reactive power is selected to be zero-sequence of the 7th harmonic, because of numerous reasons. Firstly, it could not belong to a triple harmonic (3rd, 9th etc.), because these harmonics can be normally produced by non-linear loads and behave as zero-sequence. As a result, a possible signal at these frequencies would mix with the respective harmonics of the non-linear loads. Secondly, the selection of interharmonics or even harmonics is also rejected, since [2] permits only very restricted magnitudes of them. Furthermore, the signal cannot be of relatively high harmonic order (higher than the 25th), because of interference with the filters or possible resonance inside the microgrid. Additionally, as the harmonic grows in order, EN50160 Standard reduces its permissible magnitude, which may cause problems in its detection from the DERs. Therefore the available harmonic order can be the 5th, 7th and 11th harmonics, since any resonances at these frequencies seem very unlikely because of the absence of significant capacitances in low-voltage microgrids.

The selection among the available 5th, 7th and 11th harmonics is made under the criteria of their permissible values [2] and the attenuation through the connection lines inside the microgrid. Taking into account (i) the fact that the attenuation (in percent) of the injected voltage is almost the same for each frequency (as is shown in the simulation results), (ii) the permissible limits are 6, 5 and 3.5% of the nominal voltage for the 5th, 7th and 11th harmonics [2], (iii) the necessity to easily detect the injected voltage...
and (iv) the likelihood of the natural existence of a respective zero-sequence voltage [19] makes the selection of the 7th harmonic a reasonable trade-off.

Finally, the maximum magnitude of the injected 7th harmonic zero-sequence voltage is selected to be 4% instead of 5% of the nominal voltage, allowing another 1% to any non-linear asymmetrical loads within the microgrid.

Since each DER should provide the microgrid with reactive power, even under maximum active power conditions, \( P_{\text{nom}} \), the apparent power of each converter should be oversized. Therefore, the apparent power should be determined as

\[
S_{\text{nom}} = a \cdot P_{\text{pot}} \tag{14}
\]

with \( a \) being the oversize factor. Since it was assumed that the average PF of the total microgrid load equals to 0.8, the oversize factor \( a \) corresponds to 1.25.

Fig. 5 shows in flowchart form the control strategy of the reactive power of each DER in grid-connected mode. The rms value of the zero-sequence voltage is compared with its rms value after 200 ms. If there is no reduction, it means that there is a 7th harmonic zero-sequence component because of non-linear asymmetrical loads. In such a case, the DER stops injecting reactive power.

5 Simulation tests

The simulation model of the microgrid, implemented in the Powersim software (PSIM) platform, consists of four inverter-based DERs, a battery at the PCC and constant-power loads, as seen in Fig. 1. The primary sources of all DERs are PV panels, connected in series and parallel in order to produce the necessary DC power and voltage. Each string was modelled with its \( I-V \) characteristic by calculating the MPP for given solar irradiance \( G \). The MPP model was further modified in this paper so that it can drive the PV system in power levels other than the available maximum power, even under maximum active power conditions.

Table 1 Inverter parameters

| Items          | Inverter #1, 3 | Inverter #2 | Inverter #4 | Battery          |
|----------------|----------------|-------------|-------------|------------------|
| rated power, \( S \), kVA | 12.5           | 10          | 18.75       | -                |
| nominal DC-power | 10             | 8           | 15          | -                |
| \( P_{\text{nom}} \), kW | 2              | 2           | 2           | -                |
| filter inductance, \( L_f \), mH | 15.5           | 15.5        | 15.5        | -                |
| filter capacitance, \( C_f \), \( \mu \)F | 10^-3          | 10^-3       | 10^-3       | -                |
| \( \eta_d \) | 0.3            | 0.25        | 0.45        | -                |
| gain of PI \( K_{\text{ppg}} \) | 0.01           | 0.01        | 0.01        | -                |
| switch transition | 9.95           | 9.95        | 9.95        | 9.95             |
| frequency, \( f_0 \), kHz | -              | -           | -           | 250              |

one, a feature that is necessary in the island operation mode. Each of DER\(_1\), DER\(_2\), and DER\(_3\) has two PV strings, whereas DER\(_4\) has three PV strings connected. The aggregated nominal DC-power \( P_{\text{nom}} \) of DER\(_1\), DER\(_2\), DER\(_3\) and DER\(_4\) is 10, 8, 10 and 15 kW, respectively, under standard testing conditions (STCs). A boost DC/DC converter is used in order to raise the MPP voltage to 800 V. Table 1 depicts the parameters of the inverters. The distribution lines within the microgrid were assumed to be overhead aluminium conductor steel reinforced (ACSR) 16 mm\(^2\) with \( R = 1.268 \, \Omega \cdot \text{km} \) and \( X = 0.422 \, \Omega \cdot \text{km} \). A Dy5 20/0.4 kV power transformer of 100 kVA was selected at the PCC. The utility grid was simulated with its Thevenin equivalent, that is, a voltage source of 20 kV (line voltage) in series with a complex impedance of \( R = 0.333 \, \Omega \) and \( X = 1.35 \, \Omega \), corresponding to 250 MVA short-circuit apparent power.

The battery is modelled as a variable DC voltage source in series with a resistance, where the DC voltage is a function of the battery SoC [21]. The battery bank is assumed to consist of 400 series connected 2 V cells. The capacity for performing the synchronisation is calculated by (9) equal to 232.5 A s, considering the maximum current \( I_{\text{max}} = 77.5 \, \text{A} \) and \( t_{\text{sync}} = 3 \, \text{s} \). The total battery capacity was selected equal to \( Q_b = 1600 \, \text{Ah} \), which represents a simulation-scaled value. All the loads in the microgrid were simulated as constant-power loads (Table 2). The maximum available reactive power from the DERs, operating with nominal active power, is 32.25 kVAR. This value corresponds to the maximum reactive power of all microgrid loads, thus \( Q_{\text{nom}, \text{PCC}} = 32.25 \, \text{kVAR} \). The series transformers were assumed ideal, with turns ratio equal to 100/3. The equations for the PV and battery model and the transformer data are described in Appendix.

5.1 Islanded operation, grid detection and synchronisation

Initially, the microgrid operates in island mode with each load having active and reactive powers, as in Table 1. The solar irradiance is assumed to be 900 W/m\(^2\), instead of 1000 W/m\(^2\) under STC, which corresponds to \( P_{\text{pot}} \) equal to 9 kW for DER\(_1\) and DER\(_3\), 7.2 kW for DER\(_2\) and 13.5 kW for DER\(_4\). In this case, the aggregated available active power from the DERs is 38.7 kW, while the loads demand only 29 kW. The combination of all droop characteristics results in a common microgrid frequency of 49.48 Hz, which in turn determines the desired active power of

Table 2 Load active and reactive powers

| Items   | Load #1 | Load #2 | Load #3 | Load #4 |
|---------|---------|---------|---------|---------|
| active power, kW | 7       | 8       | 6       | 8       |
| reactive power, kVAR | 3       | 5       | 2       | 5       |
the respective DER. The signal of this active power is then used by the presented control algorithm of the PV systems, in order to adjust their voltage away from the MPP voltage. Fig. 6a shows (from \( t = 0.5 \) to 1 s) the active power of each DER of the microgrid, where it is evident that the active power of the total load is covered by the DERs in proportion to their available active power, \( P_{pot} \).

Through the combination of the respective droop characteristics, the reactive power of the loads is shared among the DERs, as shown in Fig. 6b, so that the microgrid voltage settles at all nodes within the limits imposed by [2]. With the additional constraint that PF > 0.8 in each DER (see Fig. 2), a large disproportion in the sharing of the reactive power among the DERs is avoided.

At \( t = 1 \) s, the grid is initially detected by the grid-side PLL of the ESS, which in simulation terms corresponds to the closing of switch \( gsw \). The ESS immediately initialises the synchronisation process, by adjusting the voltage magnitude and frequency of the microgrid. As shown in Figs. 6c and d, the ESS discharges in order to increase the microgrid frequency to 50.5 Hz. For this reason, the SoC decreases from 50 to 45.6%, resulting in a drop of the internal battery voltage. In a similar way, the reactive power of the ESS changes, so that the microgrid single-phase rms voltage at the PCC changes from 233.26 to 230.7 V. Fig. 7a shows the microgrid and grid voltages just before and after the synchronisation. At \( t = 2.72 \) s, the synchronisation conditions are satisfied, having as a result the closing of switch \( sw \). The DERs realise the grid presence by the decrease of the rms value of the 50 Hz component \( V_{mgq_{50_{rms}}} \), as shown in Fig. 7b, and change their control strategy from droop control to grid-connected, when \( V_{mgq_{50_{rms}}} \) drops below the threshold of 6 V. In this case, the synchronisation process took about 1.72 s.

5.2 Grid-connected operation mode

When the DERs detect the grid presence, they switch to grid-connected control mode and inject active power equal to \( P_{pot} \) (Fig. 6a), after \( \sim t = 3 \) s. After synchronisation, DER\(_1\) and DER\(_4\) provide the reactive power demanded by their local loads, Fig. 6b from \( t = 2.9 \) s to 3.72 s. For this reason, the reactive power absorbed by the grid is reduced as shown in Fig. 8a. At \( t = 3.72 \) s, the ESS starts injecting the zero-sequence voltage, whose maximum value is 2.36 V for 5.76 kVAr absorbed from the grid at the PCC, as it appears in Fig. 8b. Consequently, all DERs adjust their reactive power according to the detected zero-sequence voltage, which finally results in zeroing the reactive power exchange at \( t = 3.9 \) s. In this final condition, the power losses in the distribution lines within the microgrid are calculated to be 680 W. If the reactive

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**Fig. 6 Islanded operation, grid detection and synchronisation**

*Figures and captions.*

- **a** Active power [W] of the DERs and the battery, denoted as DER\(_{1}\)P, DER\(_{2}\)P, DER\(_{3}\)P and DER\(_{4}\)P, Bat.P, respectively.
- **b** Reactive power [VAr] of the DERs and the battery, denoted as DER\(_{1}\)Q, DER\(_{2}\)Q, DER\(_{3}\)Q and DER\(_{4}\)Q, Bat.Q.
- **c** SoC [%] of the battery.
- **d** Battery internal voltage \( V_{bat} \) [V].

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power of the loads were covered by the grid, that is, the DERs delivered no reactive power, the losses in the distribution lines within the microgrid would be 1485 W. Thus, apart from the zeroing of the reactive power at the PCC, a partial optimisation regarding the power losses is achieved with the proposed method. A full optimisation regarding the power losses would require a communication between the DERs, the ESS and the grid and an optimal power flow analysis. The battery starts charging with a constant current after the grid is connected, because its SoC was lower than 100%. As can be seen from Figs. 6c and d, the internal voltage starts increasing according to the SoC.

To compare the effectiveness of the 7th harmonic selection with respect to other harmonics, the simulation test is conducted for the 5th and the 11th harmonic and the results are presented in Table 3. The 7th harmonic presents less attenuation compared with other harmonics, reinforcing its selection.
Table 3: Attenuation of the rms value of the zero-sequence voltage

| Node   | 5th, V %ΔV/V, % | 7th, V %ΔV/V, % | 11th, V %ΔV/V, % |
|--------|----------------|----------------|------------------|
| PCC    | 11.50          | 9.20           | 5.75             |
| DER1   | –2.69          | –0.43          | –1.22            |
| DER2   | –4.09          | –1.41          | –5.53            |
| DER3   | –5.30          | –2.50          | –5.54            |
| DER4   | –6.43          | –4.57          | 5.30             |

6 Conclusion

A new wireless decentralised energy management method for a microgrid is proposed. It is implemented by strategically placing an ESS at the PCC with the utility grid. The ESS uses an additional PLL to detect the grid presence and guide the microgrid to synchronisation, without requiring any further communication among the grid and the DERs within the microgrid. During the islanding operation, a method for dynamically adjusting the droop characteristic of the DER, when fed by renewable energy sources, is also proposed. Additionally, a constraint imposed on the operating PF of each DER is shown to avoid any misallocation of reactive power among the DERs, regardless of the distribution line impedances and the number and location of the DERs.

A new control method of the reactive power within the microgrid in grid-connected mode is also proposed. The aim is to zero the exchange of reactive power at the PCC and give priority to cover the reactive power of loads locally. A fourth leg in the ESS converter is controlled so as to inject a 7th harmonic zero-sequence voltage at the PCC through series transformers. The DERs adjust their reactive power according to the magnitude of the detected zero-sequence voltage. A Dv 20/0.4 kV power transformer should be placed at the PCC, so that the zero-sequence voltage is confined within the microgrid. It was shown that apart from zeroing the reactive power at the PCC – thus reducing the relative financial charge – may lead to a reduction of the power losses in the distribution lines of the microgrid. This injected zero-sequence voltage could also be used by the microgrid in order to provide ancillary services, such as lagging or leading reactive power to the utility grid. In such a case, the magnitude of the zero-sequence voltage could be determined via an appropriate signal by the utility grid operator. The proposed control methods were verified by detailed simulation.

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8 Appendix

Electrical data of the oil 0.4/20 kV transformer:

| S = 100 kVA, PFe = 320 W, Pcu = 1750 W, u0 = 4%, no-load current | I0 A referred to 0.4 kV. |
|------------------------------------------------------------------|-----------------------|
| I0 = β · G, V0c = γ · G + δ, Ismp = λ · G, Vmp = k/ξ − σ · G   | where G [W/m²] is the input irradiance, I0 [A] is the short-circuit current, V0c [V] is the open-circuit voltage, λsmp [A] and Vmp [V] are the current and voltage of the MPP, respectively. The parameters β, γ, δ, λ, ξ, and σ are given in Table 4. |

The DC voltage of each 2 V battery is described as

Vdc = 1.958 × 1.155 × 10⁻³ · x + 2.946 × 10⁻⁵ · x²

– 2.112 × 10⁻⁷ · x³

where x is the SoC of the battery.

Table 4: PV model parameters

| kWp | B | r | δ | λ | ξ | σ | 10⁻³ |
|-----|---|---|---|---|---|---|------|
| 8   | 17.2 | 37 | 537 | 15.48 | 94584.72 | 190.7 | 7.74 |
| 10  | 17.6 | 73.4 | 650.9 | 15.84 | 700703.2 | 1127.8 | 7.92 |
| 15  | 26.4 | 73.4 | 650.9 | 23.76 | 700703.2 | 1127.8 | 7.92 |

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