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A Co-simulation Procedure for Optimal Reactive Power Control in Active Distribution Networks

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***Abstract*—Distribution grids are subject to a drastic evolution in their operating conditions due to the high integration of renewable energy resources (RES) and their ability to regulate voltage. To cope with this issue, modern solar photovoltaic (PV) systems are equipped with smart inverters enabled with communication capabilities that allow the coordinated operation to offer services such as controlling voltage by appropriately setting the reactive power production. This paper proposes a co-simulation framework for smart converter reactive power control in active distribution grids. The proposed framework is used to appropriately control smart inverters installed in PV systems to inject/withdrew reactive power ensuring voltage control at the time that minimises active power losses of the active distribution grid (ADG). The proposed approach has been tested in a modified version of the Kumamoto distribution system. The suitability of the proposed framework has been demonstrated.**

Keywords—Co-simulation, differential evolution, hosting capacity, reactive power control, smart inverters.

I. INTRODUCTION

With the rise in the integration of variable renewable energy sources (RESs) in the distribution grid, the operation of the distribution system is becoming more and more complicated, even the steady-sate performance [1]. Inverters, which are commonly adopted to feed AC motors [2], can play an important role to address the new challenges of the distribution system. In particular, the modern concept of smart inverters allows the power converter to communicate and collaborate with voltage regulation. However, this enhanced feature adds more computational burdens for implementing optimal control techniques in the active distribution grid (ADGs) [3]. Co-simulation-based optimisation can be one option to consider to incorporate the optimal control technique in such ADG, [4]. However, a detailed description of co-simulation-based optimisation problem formulation and solving an optimisation problem is still a big challenge. Hence, this paper provides a detailed description of the co-simulation-based optimisation problem formulation and solves the proposed methodology for obtaining the optimal reactive power control from smart inverter in DSN.

There are various approaches for controlling reactive power in the scientific literature [5], [6], [7], [8]. In the case of a distribution network, OPF created using conventional power-flow techniques like Gauss-Seidel, and Newton-Raphson and fast decoupled load flow may not converge [9]. So, the distribution network is modelled using the LinDistflow equations or sensitivity-based modelling in most works on optimal reactive power control. However, convergence in such cases requires more time, depending on the complexity of the network under consideration. Also, due to the increased fluctuations in the operating condition of the distribution system network (DSN), the optimisation problem is required to be completed on short time. Co-simulation-based optimisation is one of the options to perform faster optimisation. Also, the sizing of the RES is also an important aspect to consider before implementing the optimal reactive power control in the network. The capacity of the smart inverter affects the allowable reactive power support from the RES. Also, the nature (inductive or capacitive) of the reactive power support has a huge impact on the total network loss in the network. To operate the network optimally with minimum network loss, optimal reactive power support is to be considered. Optimal reactive power control in power system network is studied in [10]–[13]. However, these papers do not consider the sitting and sizing of renewable energy sources (RES) prior to considering the optimisation problem. Hence, in this paper, hosting capacity (HC) analysis is done prior to implementing the optimisation problem for reactive power control. Further insights on smart converter reactive power control are provided in the review paper [14].

The focus of this work is to propose a precise method to perform co-simulation optimal reactive power regulation in DSN to minimise total active power losses. The co-simulation framework has been created between a power system specialised software (PSSS) and a programming language environment. The co-simulation-based optimisation problem has been constructed using the load flow equation of the PSSS and defining a non-explicit objective function in the programming language environment. Specifically, the PSSS and the programming language exploited in this paper are DIgSILENT PowerFactory and Python, respectively. This method has been applied to the Kumamoto distribution network. The summary of the contribution made in this paper are listed below:

1. A voltage control approach based on co-simulation framework in order to optimise the reactive power of the

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smart converters and minimise the active power losses of the DSN (see Section II).

2. Implementation of a modified version of the Kumamoto test system, including daily load profiles and the siting and sizing of PV systems by HC analysis (see Section III.A).

The following sections make up the remainder of the paper. Sections II describes the proposed co-simulation-based optimiation problem. Section III starts presenting the development of a modified version of the Kumamoto test system and demonstrates the use of the proposed framework. Finally, the last section highlights the analyses' main contributions of this paper.

II. PROPOSED CO-SIMULATION BASED OPTIMISATION PROBLEM

In this section, the proposed framework to solve the co-simulation-based optimisation problem is presented. The section starts by presenting the reactive power control as an optimisation problem; the objective function is to minimise the total system active power losses at the time that carefully controls the voltages to keep them inside the predefined voltages boundaries. In this paper, the voltage boundaries are formulated as a penalty function inside the objective function. The second section shows the co-simulation framework used for solving the optimisation problem by a combination of Python programming language and DIgSILENT PowerFactory via an API (application programming interface).

A. Reactive power optimisation formulation

In this paper, the authors are looking into taking the maximum advantages of the PV smart converters installed in an ADG. The proposed control looks into controlling the voltage at the time of minimising the total active power losses. It is done by optimally defining the reactive power production of each smart inverter.

The proposed control is based on the solution of an optimisation problem formulated in the most general way as minimising an objective function $f(\boldsymbol{Q_{PV}})$:

$$\min_{\boldsymbol{Q_{PV}}}[f(\boldsymbol{Q_{PV}})] \tag{1}$$

where the vector $\boldsymbol{Q_{PV}}$ includes the decision variables represented by the reactive power setpoint of each solar PV smart inverter ($Q_{PV,i}\ \ \forall\ i = 1, 2, \dots N_{PV}$):

$$\boldsymbol{Q_{PV}} = [Q_{PV,1} \quad Q_{PV,2} \quad \cdots \quad Q_{PV,N_{PV}}] \tag{2}$$

The objective function is to minimise the active power losses of the ADG at the time to ensure that the operating voltage is inside the desired boundaries. Therefore, a composed objective function is created by a weighted linear combination of the active power loaded P_{loss} and the system voltage penalty function f_V:

$$f(\boldsymbol{Q_{PV}}) = \alpha_1\, P_{loss}(\boldsymbol{Q_{PV}}) + \alpha_2\, f_V(\boldsymbol{Q_{PV}}) \tag{3}$$

where α_1 and α_2 are the weight factors. The system active losses P_{loss} are calculated as sum of the losses on each branch defined as follows:

$$P_{loss} = \sum_{l=1}^{N_L} Re\left\{\frac{\left|\beta_{l,b}\, V_b - \beta_{l,c}\, V_c\right|^2}{Y_{bc}^*}\right\} \tag{4}$$

where $\beta_{l,b}$ and $\beta_{l,c}$ are binary parameters and they indicate if the b-th (c-th) bus is connected (1) or not (0) to the l-th branch and V_b (V_c) is the respective nodal voltage, N_L is the number of lines, Y_{bc}^* is the mutual-admittance between the two interconnected nodes and * indicates the complex conjugate.

Additionally, the penalty function presented in (3) as f_V is defined as an expression of a number of buses exceeding the predefined quality boundaries expressed as the minimum (V_{min}) and the maximum (V_{max}) voltage limits. Fig. 1 shows the rule implemented in the programming language environment, where $\boldsymbol{V}$ is the vector of the nodal voltages, N_{bus} represents the total number of buses in the ADG, and pen is the penalty value. The function f_V is the square of the outbound index number to force the optimisation to avoid undesired operating conditions.

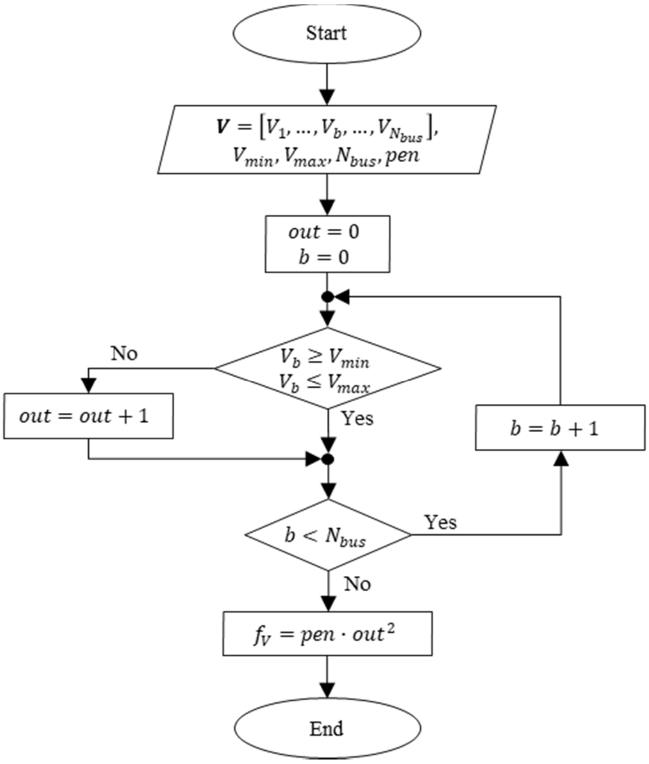

Fig. 1. Flowchart illustrating the penalty rule used in the voltage penalty function f_V.

In this paper, the authors are interested in taking advantage of the PV smart inverter ability to deliver the voltage control aiming to minimising the active losses by optimising the reactive power. Therefore, the reactive power production of the i-th smart converter must fulfil the following boundary constraint:

$$Q_{PV,i} \leq \pm\sqrt{\left|S_{PV,i}\right|^2 - {P_{PV,i}}^2} \qquad \forall\ i = 1,2,\dots,N_{PV} \tag{5}$$

where $\left|S_{PV,i}\right|$ is the rated apparent power of the i-th smart PV converter, whereas $P_{PV,i}$ is the PV active power production, considered as a known value according to maximum power point tracking, desumed from weather forecast. Furthermore, according to the IEEE 1547-2018 standard, the smart inverter reactive power is limited to the 45 % of the rated power, therefore an additional constraint is embedded in the optimisation problem, defined in the following:

$$-k \cdot |S_{PV,i}| \leq Q_{PV,i} \leq k \cdot |S_{PV,i}| \qquad \forall\, i = 1,2, \ldots, N_{PV} \qquad (6)$$

in which $k = 0.45$.

B. Co-simulation Framework

The proposed framework takes advantage of the co-simulation paradigm, where different subsystems of a coupled optimisation problem are solved in a distributed manner. In this specific case, the coupled problem is the mathematical optimisation situation that requires the evaluation of the steady-state performance of the ADG. The framework formulates in a very clever problem the objective function by defining non-explicit objective function and constraints by using the numerical results coming from the solution of the steady-state network. Further details on co-simulation properties are provided in [13].

Fig.2 shows a high-level description of the proposed framework for the co-simulation-based optimisation problem for reactive power control in the distribution network. Additional details on the co-simulation methodology are described below.

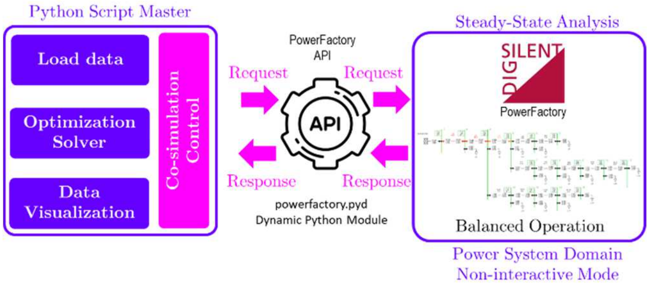

Fig. 2. General schematic of the proposed co-simulation framework-based optimisation problem for reactive power control in the distribution network.

The electrical model of the ADG is implemented using DIgSILENT PowerFactory. Also, DIgSILENT PowerFactory is used as an engine to calculate the steady-state conditions of the electrical network by means of AC load flow routine.

The proposed framework takes advantage of the Python application programming interface (API) provided by PowerFactory to control and automatise power system calculations. The API is an object oriented programming library to set the parameters and control the simulation in engine mode by means of Python. In this contest, a Python script contains the primary process required to solve the optimisation problem where the objective function is evaluated from the numerical simulation results using DIgSILENT. Hence, this procedure avoids the definition of the non-linear AC load flow equations, exploiting the ones embedded in the PSSS.

III. SIMULATIONS AND RESULTS

The proposed framework is demonstrated in this section. The authors decided to define a modified version of the well-known Kumamoto distribution system originally presented [15], in which the single-line diagram of the test system is shown in Fig. 3. In particular, the network is modified in order to define a suitable dataset to apply the reactive power optimisation problem defined in the previous section.

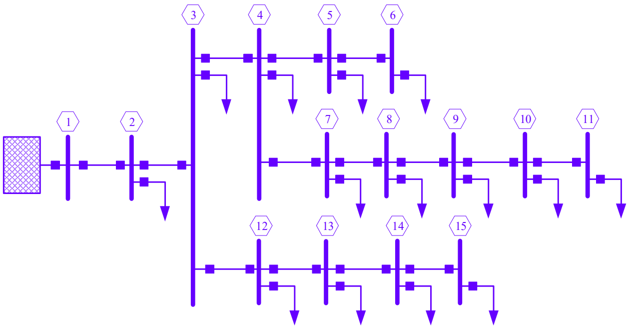

Fig. 3. Test System: Kumamoto distribution grid.

A. Modified version of the Test System

Preliminary analyses are carried out on the original version of the Kumamoto network of [15] to define line thermal ratings, load profiles and PV system size and location. In particular, load flow routines are performed considering the original network configuration with the orginal load demand of 18.9 MW and 1.34 MVAr as active and reactive power, respectively. In Table I is shown the currents yield by the simulation, the consequent chosen rated power, and the resulting loading on each line.

TABLE I. PROPOSED RATED CURRENTS OF THE MODIFIED KUMAMOTO NETWORK

Line	Obtained Current [kA]	Rated current [kA]	Loading [%]
Line 1-2	0.999	1.00	99.9
Line 10-11	0.347	0.50	69.3
Line 12-13	0.052	0.26	20.1
Line 13-14	0.048	0.26	18.3
Line 14-15	0.022	0.26	8.5
Line 2-3	0.966	1.00	96.6
Line 3-12	0.073	0.26	28.1
Line 3-4	0.816	1.00	81.6
Line 4-5	0.088	0.26	33.9
Line 4-7	0.577	1.00	57.8
Line 5-6	0.018	0.26	6.9
Line 7-8	0.477	1.00	47.7
Line 8-9	0.425	0.50	85.1
Line 9-10	0.391	0.50	78.3

Daily load profiles with 15 mins resolution are associated to the loads at the power factor provided by the original test data is kept constant for each node. The profiles follow typical commercial load, daylight working day commercial load and evening commercial load described in [16]. Fig. 4 shows the quarter-hour active and reactive power load profile, in which the active power ranges from 1.98 MW to 16.88 MW and the reactive power varies from 0.17 MVAr to 1.15 MVAr.

Finally, distributed energy resources (DER) are installed to the original Kumamoto test system to realise an ADG. The size and location of the PV systems are evaluated by means of hosting capacity (HC), which is a powerful method for determining the maximum capacity of new distributed generation that can be installed on each bus of the grid, without exceed network constraints. The HC analysis considers the PV smart inverter working unity power factor to evaluate the maximum installable capacity if the PV systems cannot regulate the reactive power. The HC analysis takes advantage of one of the power system specialised software

(PSSS) toolbox, and it is briefly described below; further details on PSSS tools for HC analyses are explained in [17].

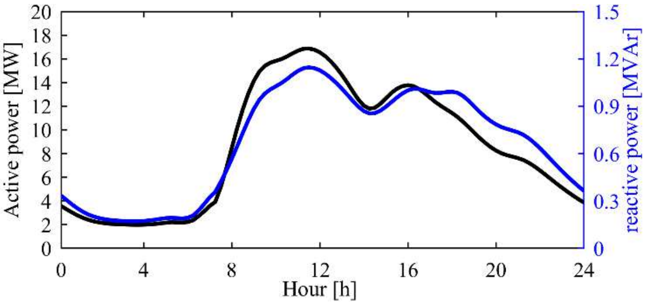

Fig. 4. Quarter-hour daily total load active and reactiveprofile.

Following the network modelling, the candidate buses for installing the PV system must be chosen. Power flow simulations are performed iteratively for each bus, with the PV capacity being adequately adjusted according to voltage and thermal limits at each iteration. The end of the iteration is reached when the first constraint limit is reached, providing the maximum power that can be injected from the analysed candidate bus without exceeding any constraint. The HC is applied in two extreme operating conditions to obtain a more reliable solution: the day's minimum and maximum load values. In this paper, DIgSILENT PowerFactory is the chosen PSSS for HC analysis, and the user manual contains additional information on this methodology [18]. The simulation are carried out setting the slack bus—the external grid—voltage of 1.02 pu, as in [15], with voltage limits of [0.95, 1.05] pu and maximum line loading of 100%. The obtained results are reported in Table II, in which Bus 1 is not considered in the analysis as that is the point of connection to the external grid.

TABLE II. RESULTS OF HC ANALYSIS: PEAK AND MINIMUM LOAD CONDITIONS

Bus	**Peak Load**				**Minimum load**			
	P [MW]	**L. [%]**	**V [pu]**	**Limiting element**	**P [MW]**	**L. [%]**	**V [pu]**	**Limiting element**
2	36.38	**99.8**	1.02	1-2	21.5	**99.9**	1.034	1-2
3	35.78	**99.9**	1.02	2-3	21.38	**99.9**	1.034	2-3
4	33.26	**99.8**	1.024	3-4	21.22	**99.8**	1.035	3-4
5	6.68	**99.8**	1.02	4-5	5.44	**99.9**	1.041	4-5
6	5.36	**99.9**	1.02	5-6	5.18	**99.9**	1.043	5-6
7	29.7	**99.9**	1.029	4-7	20.7	**100**	1.037	4-7
8	28.38	**99.9**	1.031	7-8	20.5	**100**	1.037	7-8
9	17.65	**100**	1.034	8-9	10.51	**99.9**	1.046	8-9
10	17.02	**99.9**	1.034	9-10	10.48	**99.9**	1.047	9-10
11	16.19	**99.9**	1.035	10-11	10.32	**99.9**	1.048	10-11
12	6.16	**99.9**	1.02	3-12	5.3	**99.9**	1.041	3-12
13	5.91	**99.8**	1.023	12-13	5.27	**99.9**	1.046	12-13
14	5.85	**99.9**	1.028	13-14	4.64	87.7	**1.05**	Bus 14
15	5.38	**99.9**	1.029	14-15	3.81	72.2	**1.05**	Bus 15

The maximum loading (L.) is the primary limiting bound in both cases. Specifically, during peak load, the minimum and maximum PV capacities at Bus 6 and Bus 2 are, respectively 5.36 MW and 36.38 MW. Furthermore, the installation of PV results in a slight increase in voltage on the examined buses, with the maximum occurring at Bus 11 with 1.036 pu. During the minimum load, the HC result has a lower PV capacity while the voltages are higher than in the previous case. Indeed, Bus 14 and Bus 15 reached the maximum voltage bound. The minimum and maximum capacity PV smart inverters are found on Bus 15 and Bus 2, with capacities of 3.18 MW and 21.50 MW, respectively.

The fourth step in modifying the original Kumamoto test system into an ADG is the integration of PV smart inverters. In relation to the HC results, the PV systems have been connected on Bus 2 (PV_2) with a capacity of 20 MVA and on Bus 11 (PV_{11}) with 10 MVA. The first is the bus with the highest generation that can be installed, whereas the second is the bus on which is connected the most significant load. The PV capacity choice criterion is based on obtaining central hours of the day with production more significant than the required load. The PV systems' daily production is set exploring a winter day profile provided in [16], and their quarter-hour production is depicted in Fig. 5.

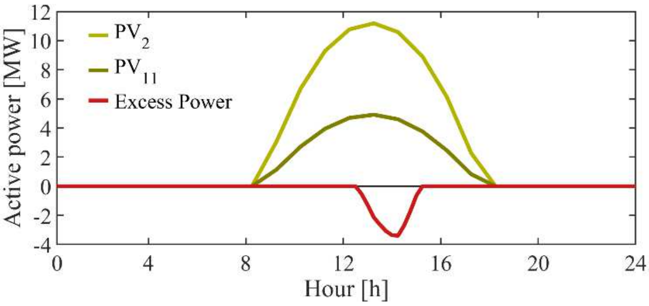

Fig. 5. Installed PV system active power production.

The PV smart inverters supply power to the network between 8:15 to 17:45. The peak production occurs at 13:00 with roughly 18.6 MW, and a total energy of approximately 113 MWh. Furthermore, from 12:30 to 14:45, the PV systems production exceeds the required load, exporting the difference to the external network (red bars). Finally, Fig. 6 depicts the maximum and average loading of the lines with and without the PV penetration. The PV penetration positively impacts the line loading; the higher the penetration, the more significant the loading reduction. During daylight hours, the maximum loading has a mean decrease of 19.1%, where the maximum loading moved from 88.6 % to 69.1 %. Analogously, the mean loading is subject to a mean reduction of 14.5 %. The modified Kumamoto test system will be publicly available at the following GitHub repository: https://github.com/fglongatt/Modified_Kumamoto.

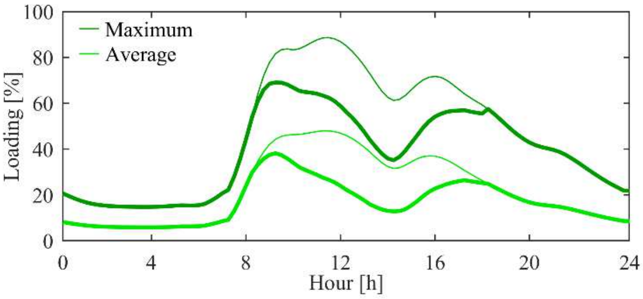

Fig. 6. Maximum and average line loading with (thicker) and without (thinner) PV production.

B. *Reactive power Optimisation*

The co-simulation framework was modelled using PowerFactory as the PSSS and Python as the programming language environment. Hourly load flow simulation, resulting from the averaging of the quarter-hour profiles, is configured in PowerFactory to exploit active and reactive power balance equations as non-explicit constraints, as well as the losses and the voltage penalty function, in the optimisation problem. In particular, the load flow routines are carried out keepng the slack bus voltage to 1.02 pu, and controlling the active and reactive power (PQ mode) of the PV systems. In particular, the active powers is provided from the hourly average of the trends in Fig. 4, whereas the reactive powers represent the control variable. In Python, the SciPy library [19] was used to model the optimisation problem using the Differential Evolution solver [20]. Considering the HC results from Table II, setting 1.02 pu as slack bus target voltage, the worst voltage condition is obtained in the minimum load scenario, therefore voltage boundaries for all buses have been set to V_{min} = 0.99 pu and V_{max} = 1.035 pu, to force the optimisation to re-dispatch the reactive power, whereas the penalty constant (pen) is 1000 to set an higher burdern to this term in (1) while putting 1 to the weighting factors. The simulations have been performed on a laptop with an 8 core i7-10870H processor running at 2.20 GHz and a RAM of 32 GB.

Fig. 7 depicts the base case losses as well as the optimal losses as result of the optimisation problem. During the day, the base case losses range from 4.7 kW to 132.6 kW, for a total energy loss of 862.5 kWh. On the contrary, the optimal solution has lower volatility, varying from 3.0 kW to 130.9 kW, with a total energy loss of 843.0 kWh, achieving a net daytime losses reduction of 19.5 kWh, equal to the 2.3 % of the original losses. This implies an increase of exported power during the peak PV production, and reduction of power import in the night-time. Furthermore, it can be observed that the main reductions are obtained in the periods of a low required load, as well as during the peak load, whereas in the medium load conditions the benefits are neglectable.

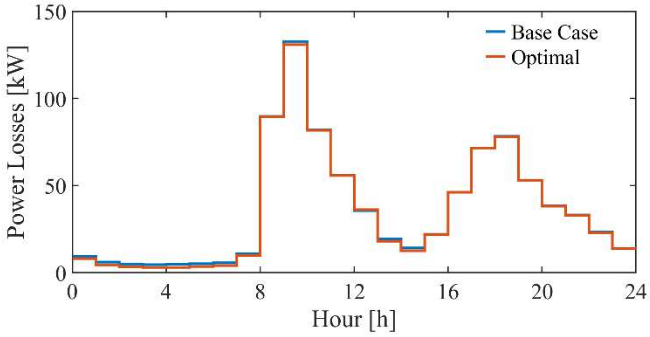

Fig. 7. Base case (blue) and optimal (red) system losses.

Fig. 8 and Fig. 9 depict the statistical information of the nodal voltages in the base case and the optimimal one, respectively. On the one hand, in the base case, the average nodal voltage is above to the upper bound of 1.035 pu until 07:00, owing to the low loading of the lines and for the low required load. Following that, the increase in load as well as the energy supply by PV systems, cause a sudden drop in average voltage, reaching a reduction up to 1.016 pu at 09:00. Throughout the day, the average voltage follows an increasing and decreasing trend with lower slopes. The optimal solution, on the other hand, meets the voltage constraints throughout each hour. Specifically, until 07:00, the average voltage is close to the slack bus's target voltage. Then it fluctuates between a maximum of 1.030 pu and a minimum of 1.020 pu.

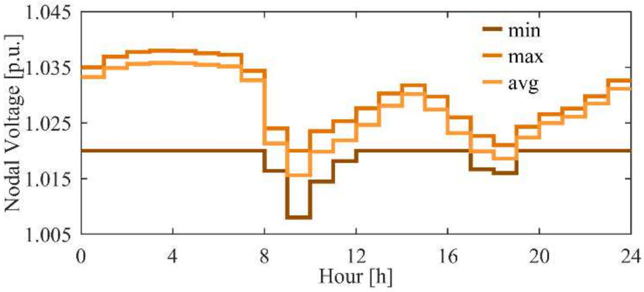

Fig. 8. Base case minimum, maximum and average hourly nodal voltage.

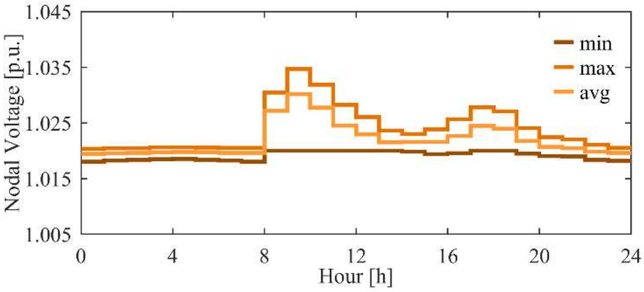

Fig. 9. Optimal minimum, maximum and average hourly nodal voltage.

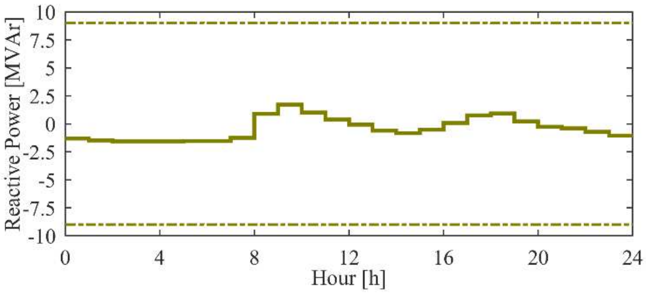

Fig. 10. Hourly optimal reactive power provided by the PV 2 converter.

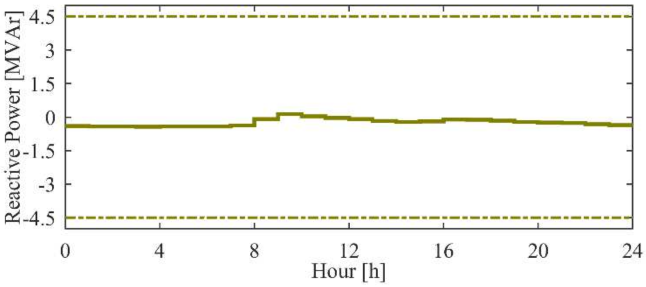

Fig. 11. Hourly optimal reactive power provided by the PV 11 converter.

Finally, Fig. 9 and Fig. 10 show, respectively, the optimal reactive power provided by PV 2 and 11 systems to the network and the respective maximuim and minimum boundaries (dashed-dotted lines). In particular, the boundaries of the two smart converters are always constrained by (6) because the active power produced during the day is lower than the 55% of the rated apparent power, as shown in Fig. 5. In addition, the voltage trend closely follows the dispatched reactive power of the PVs: when they produce inductive reactive power (negative sign), the optimal average voltage is lower than the base case ones; whereas when they withdraw inductive reactive power (positive sign), the optimal average voltage is higher than the base case ones.

IV. CONCLUSIONS

This paper proposes a co-simulation framework for smart converter reactive power control in active distribution grids. The framework considers the reactive power control as an optimisation problem, where the active power of the ADG is minimised at the time that the bus voltages are kept inside the desired boundaries. That is done by the sum of the total system active power losses and a rule-based penalty function applied to the bus voltages. The framework used a custom co-simulation framework, using DIgSILENT PowerFactory as an engine to calculate the steady-state performance of the ADG, and Python is used to coordinate the main modules, including the solver used to accomplish the solution of the optimisation problem. Following that, the DE algorithm was used to dispatch the reactive power of the PV converters in a co-simulation-based optimisation problem to minimise losses and limit nodal voltages. A modified version of the Kumamoto distribution test system has been created for this paper; it includes load and solar PV generation profiles, defined load rating for the power lines and, more importantly, the integration of the solar PV smart inverter is based in the calculation of the hosting capacity of the proposed test system. The size and location of the PV system has been developed by means of HC approach, supposing unitary power factors of the PV. Further works could take into account different network operating condition to effectively define the maximum DER penetration, or addressing the definition of reactive power costs to remunerate the service provided by the PV system owners.

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