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A Co-simulation Framework for the Provision of Support Services by Smart Residential Users in LV Distribution Systems

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***Abstract*—In this paper, a co-simulation framework is presented to assess the impact on the distribution network of provision of support services (i.e. voltage support) by smart residential users. Such users are capable of providing flexibility by increasing/decreasing generation/consumption controlling the operation of an available set of flexible assets. The control of assets such as PV systems, electrical vehicles (EVs), heat storage and micro combined heat and power (mCHP) units is done by a Customer Energy Manager (CEM) after receiving flexibility requests as a result of an Aggregator-Distribution System Operator (DSO) interaction. In the presented framework, the distribution system is modeled in OpenDSS while the aggregator-flexible asset interaction, including the market-clearing procedure, is modeled using the Energy System Simulator (ESSIM). Results from several simulated scenarios are presented. According to the presented results, in summer, where over-voltage issues are expected due to the high PV penetration, a solution rate of 90% is estimated. For winter, in which under-voltage issues are more predominant, the solution rate is found to be around 70%.**

***Index Terms*—Demand response, flexibility, LV distribution networks, voltage support**

I. Introduction

The European energy system is under an ongoing transformation towards a carbon-free system [1]. Currently, there is a clear rise in the adoption of more environmentally friendly energy sources e.g. wind and solar [2], as well as the so-called low-carbon energy technologies e.g., electrical vehicles (EVs), electric heat pumps, micro combined heat and power (mCHP) units, etc by residential users [3]. The introduction of these low-carbon energy technologies aims to help to decarbonize other sectors such as transport, heating, and cooling [4], reducing their dependence from fossil fuel. Nevertheless, as most residential users are connected to low voltage (LV) distribution networks, Distribution Systems Operators (DSOs) expect an increase of operational issues (e.g. over- and under-voltage problems, congestion problems, overloading of assets, etc.) due to the large penetration of such technologies.

Several studies have investigated the impact of large penetration of different low-carbon energy technologies in distribution systems. For instance, in [5], the total annual expected number of overvoltage issues in residential networks due to the large penetration of PV systems was investigated. Results showed that an additional control (curtailment) strategy is required to maintain the voltage level across the system within the required limits. Similar results and conclusions were presented in [6]. In [7], an impact evaluation was performed in LV networks with high penetration of distributed CHPs. Results showed that in case of large penetrations, network reinforcement will be required, especially due to the expected overloaded operation of the distribution transformers. Similar operational challenges are expected in distribution networks with a high number of EVs charging simultaneously, especially if this occurs around peak time [8].

Although the clear challenge that represents the operation of a distribution system with a large penetration of technologies such as PV systems, EVs, mCHP, among others; if properly coordinated, these resources can provide support services to the DSOs [9]. Services such as congestion management, voltage support, balancing services, etc, can be provided by residential users enabled by an aggregator [10]. Nevertheless, before the provision of such services occurs, it is necessary to study its impact on a large scale setting and validate their operational effectiveness. To do this, a co-simulation framework for the provision of support services (i.e., voltage support) by smart residential users is presented in this paper. The developed framework is used to assess the impact of the provision of such services on the operation of the distribution network. Different modeling blocks have been considered for the aggregator, the DSOs, and the flexible assets within the smart residential users.

II. Developed Co-Simulation Framework

The developed co-simulation framework is presented in Fig. 1. This framework is composed of an Aggregator logic module, a DSO logic module, and the residential users' modules. Two types of residential users are considered: Smart residential users, capable of providing flexibility by increasing/decreasing generation/consumption controlling the operation of an available set of flexible assets, and regular residential users. Flexible assets at the smart residential users are controlled via a Customer Energy Manager (CEM) interface,

Table I
OPERATIONAL DATA OF THE MCHP

PowerCode	100	90	75	65	20
Turbine speed [10^3 RPM]	240	230	215	205	190
Electric Power [kW]	3.2	3.08	2.53	2.07	1.38
Thermal Power [kW]	16.4	15.24	12.83	11.32	9.24
Fuel Input [l]	20.4	19.22	16.29	14.09	11.31

which has direct communication with the Aggregator. As can be seen in Fig. 1, the Aggregator can exchange control signals and flexibility information for each of the smart residential users via the CEM, in charge of controlling the operation of the mCHP, PV system, EV charger, and the heat storage unit. An additional gas heater unit is considered in case the mCHP is not able to supply all the heat demand. Regular residential users cannot provide flexibility, thus, are modeled as inflexible constant power injections.

A more detailed description of the flexible assets modeling and the aggregator-DSO interaction loop is presented next.

A. Flexible Assets Modeling

As previously discussed, power generation/consumption flexibility (aiming to provide voltage support services) can come by controlling different flexible assets (mCHP, EV, PV system, heat storage) available at each of the smart residential users.

mCHP: mCHPs are usually located near to users where both types of energy (electricity and heat) are demanded. Commonly, in small-scale CHP, heat demand drives the operation of the mCHP system, while the electric power becomes a by-product. The mCHP considered here corresponds to a single phase unit with a maximum output power of 3.2 kW operating with a nominal voltage of 230 V. The lowest and highest setting (PowerCode, see Table I) that this mCHP can operate corresponds to a turbine speed of 190 and 240 10^3 RPM, respectively. The thermal power and electric power relation of the micro CHP can be seen in Table I. Finally, as the start-up time is lower than the time-step considered for the simulations (i.e. 1 h), this can be disregarded.

Heat Storage: A domestic hot water buffer of 50 l capacity operating between $40°$C and $90°$C is considered. The heat storage offers flexibility by buffering excess heat produced by the mCHP which will be used to satisfy the residential heating demand at a later time instead of depending on the gas heater. For the sake of simplicity, the storage is modeled without leakage or the ability to charge from the gas heater.

PV System: Residential PV systems are modeled as constant active power injection. For this, real PV systems generation measurements are used. In the Netherlands, the typical nominal capacity of residential PV systems is within the range of 3 and 6 kWp [5]. Flexibility can be provided by the PV systems in case it is required by curtailing active power exported to the distribution system.

EV Charger: The EV charger station is a single-phase system with a maximum input/output power of 1x16 A and a nominal voltage of 240 V. The EV charger cannot dispatch reactive power, and thus, it operates at unity power factor. Negative charge i.e., bi-directional charging or V2G services, have not been considered. Flexibility can be provided by the EV charger if required by increasing or reducing the amount of active power consumed by the EV in charging mode. EV charging station behaviour is simulated by randomising three factors: (i) fuel economy (14-27 kWh/100km) [12] [13] per user, (ii) the plug in (16:00-19:00) and plug out (06:00-08:00) times and (iii) kilometres driven during the day (μ=60.0 km, σ=24.0 km).

B. Aggregator-DSO Interaction Loop

The aggregator and DSO logics are modeled as different agents for separation of concerns - the aggregator is unaware of the distribution network topology or its constraints and the DSO is unaware of portfolio management or flexibility of affiliated smart residential users. Such abstraction and distributed manner of solving problems also help prevent competition-sensitive information (from multiple aggregators) being exchanged between competing agents and a third party. In this case, a single aggregator is considered to whom all residential users are affiliated to. The aggregator, assets, and their flexibility are modeled as in [14]. In a similar real-time approach to solving voltage problems, this algorithm operates in six steps, as described in Fig. 2 and explained as follows:

Step 1 - Flexibility Aggregation: In this step, all participating assets $x_k \in X = \{x_1, x_2, \ldots, x_N\}$ send their instantaneous flexibilities to the aggregator in the form of a demand function, $d_k(p)$, stating the agent's demand against resource price p. The demand function is measure of both the flexibility of the asset and its willingness to deviate from its desired energy state (determined by a marginal cost price, p_{mc}).

Step 2 - Market Clearance: Once the aggregator has assimilated all the demand functions, it balances the market, i.e. it finds an allocation of electrical power over all agents that balances demand and supply. When ignoring network constraints, the allocation problem is solved by finding the general equilibrium price p^* such that:

$$\sum_{k=1}^{N} d_k(p^*) = 0 \tag{1}$$

For this price, market clearance is established, i.e. total demand equals total supply for all agents.

Step 3 - Grid Impact Measurement: Subsequently, a load-flow analysis on the distribution network is performed, taking into account the powers in the above demand-supply solution as the instantaneous active powers in the various leaf nodes of the network. Solution to the load-flow problem gives a list of voltages $V = \{v_1, v_2, \ldots, v_N\}$ that can be used to assess the effect of this energy mix on the nodal voltages in the distribution grid.

Step 4 - DSO Observation: The DSO sets voltage thresholds, v_{min} and v_{max} for each node in the grid. Using this information and V, the agent sends a voltage status map

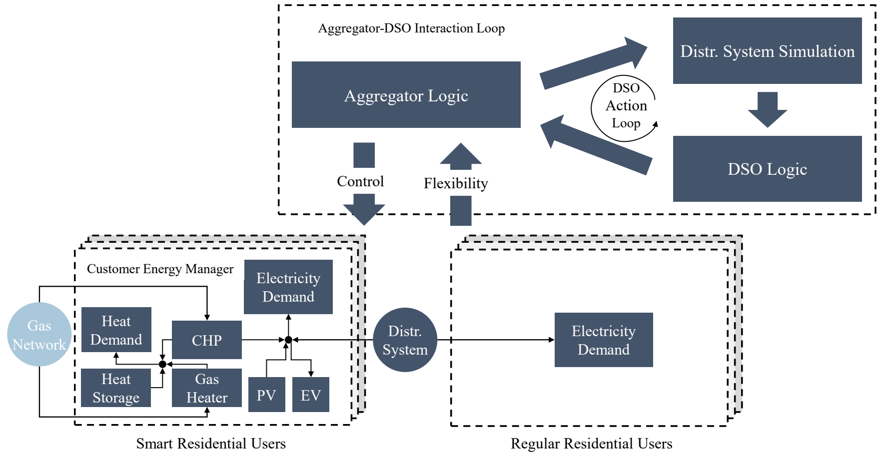

Figure 1. Co-simulation framework developed. Flexibility assets (mCHP, PVs, EVs, heat storage, etc), the aggregator logic and the smart and regular residential users has been simulated using ESSIM [11], while the electrical distribution system has been modeled and simulated using OpenDSS.

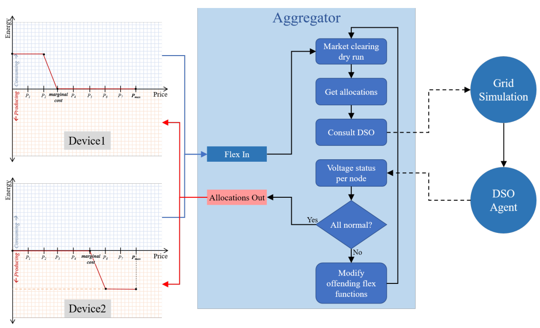

Figure 2. Aggregator-DSO interaction loop composed of several steps: Flexibility aggregation, market clearing, grid impact measurement (Consult DSO), voltage problem correction and asset allocation.

$f : X \to V_s$ where $V_s = \begin{cases} \text{"over-voltage"}, & v_k > v_{\max} \\ \text{"under-voltage"}, & v_k < v_{\min} \end{cases}$ to the aggregator informing it of any voltage issues in each leaf node, x_k of the network.

Step 5 - Voltage Problem Correction: The aggregator attempts to solve an over-voltage problem by incentivizing consumption or disincentivizing production at that particular node. This can be achieved by shifting the demand function to the right by a pre-determined price, Δp_k for the offending nodes. This makes consumers less likely to reduce energy consumption and producers less likely to increase energy production. The aggregator tries to solve an under-voltage problem by performing the vice-versa. These can be seen in Fig. 3.

Modifying demand functions calls for a new round of market clearance and subsequent Steps 3, 4 and 5 of the loop to be performed. This is done until all voltage problems are resolved or a threshold for maximum number of attempts is exhausted.

By modifying demand functions, the aggregator *simulates* a higher/lower price market condition for the consumer whose flexibility was exploited to fix a nodal voltage problem. This results in different nodal prices p_k^* for different consumers in the grid. In essence, the cost of fortifying the grid saved as a result of improved power quality was passed from the network operator to the customer. So it is worthwhile to investigate in future research, a remuneration for the flexibility provided by the customer and also to calculate if this makes a viable business case for investment in flexible assets.

Step 6 - Asset Allocation: Once an appropriate demand-supply balance is determined with minimal impact to the grid, the balancing price p^* is propagated down to assets. At each asset, p^* is modified by offsetting it by the shift (Δp_k) that was performed in Step 5, resulting in the nodal price p_k^*. The energy allocation for an asset x_k with demand function d_k is then $d_k(p_k^*)$. The steps in this algorithm are repeated for each time step of a pre-determined fixed interval.

III. Case of Study

To model electricity and heat consumption of all the residential users, real profiles are used and scaled appropriately to recreate potential voltage problems. These profiles are obtained from smart meter and gas consumption measurements, provided by a Dutch DSO. The electrical distribution system used corresponds to one of the types identified networks in The Netherlands [15]. This distribution system is characterized by having a total of 87 residential consumers (in total, 17 are considered smart residential users, while the remaining are regular users) located in more than eight feeders. This topology and asset configurations, using information provided by one Dutch DSO, have been modeled in ESDL [16], which serves as an input for the aggregator simulation (ESSIM) and the distribution system simulation (OpenDSS [17]). Cable information (features and length) from the distribution network until the point of connection of each residential user has been also included in the simulation model. This LV distribution system is supplied by a single distribution transformer with nominal rating power of 400 kVA and voltage ratings of 11 kV/400 V. The voltage at the swing-bus is considered to be 1.03 p.u. Actions to mitigate over-voltage and under-voltage issues are requested if the voltage magnitude of the point of connections of the smart residential users surpass 1.10 p.u. or if it is below 0.90 p.u., respectively. The results presented below corresponds to simulations for 7 days during

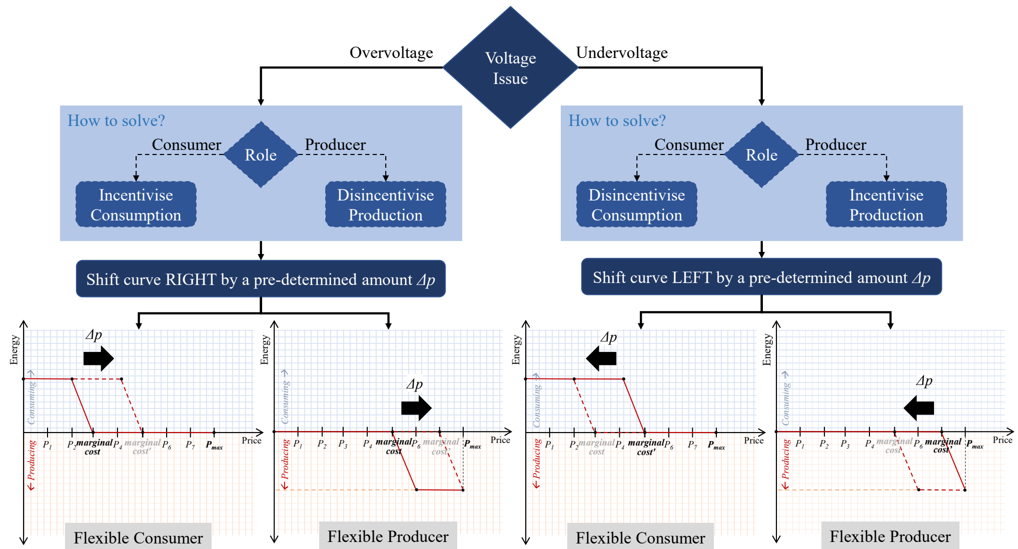

Figure 3. Aggregator decision tree implemented. Flexibility requested by the Aggregator to the smart residential users via the CEM depending of the voltage issue expected by the DSO: Overvoltage and undervoltage. Flexible assets (producer or consumer) will shift their generation/consumption a Δp depending on their marginal cost.

summer (when PV penetration is high) and in winter. Results are presented for a smart residential user at node 55 who is located closer to the end of one of the feeders. For each period of simulation, two strategies are explored - one where local generation (using mCHP) is favored over importing from the grid and one where the opposite holds true. This is done by setting a cheaper marginal cost for one producer compared to the other. The aggregator simulation chooses cheaper producers over more expensive ones.

A. Scenario Analysis

Scenario I: Summer week simulation (Import from grid favored)

In summer, due to the high irradiation levels and the high PV penetration, over-voltage issues are experienced by the user 55 during day time, as can be seen in Fig. 4. To correct this problem at nodes where voltages magnitude surpass the maximum voltage threshold (1.10 p.u), and a smart residential user is located, the aggregator requests flexibility in the form of increasing consumption and reducing production. The response from the smart residential user 55 after such request is also shown in Fig. 4, in which can be seen that, since importing from the grid is favored over local generation, the PV system is curtailed and the mCHP is mostly switched off or produces too little to help solve the voltage problem. Regarding the EV, they are unable to provide flexibility during the day, as the car is away and not plugged to the network for charging. Notice that after the user provides the requested flexibility the frequency of the over-voltage issues is significantly reduced, as shown in Fig. 4. A similar operational strategy is followed by other smart residential users that experience any over-voltage issue.

Scenario II: Winter week simulation (Import from grid favored)

In winter, due to the low PV generation and higher electricity

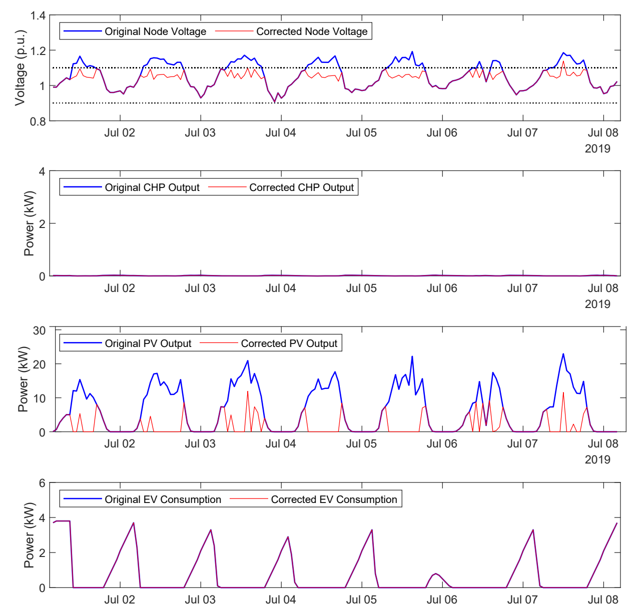

Figure 4. Summer time simulations for User 55. In this scenario, importing from the grid is favored over turning on the mCHPs to meet the electricity demand. The EV is programmed to plug in at 17:00 and plug out at 08:00 the following day.

and heating demand, the prominent problem in the distribution network is under-voltage issues. This can be seen on multiple occasions during the week in Fig. 5. To solve these problems, the aggregator request flexibility from smart residential users in the form of increasing production and reducing consumption. Results after the users provided the requested flexibility can be seen also in Fig. 5. Following the aggregator's requests, increased production of the mCHPs and curtailment in the consumption of the EV can be seen. Notice from Fig. 6 that not in all moments when them CHP is encouraged to produce, the residential heating demand is high enough to benefit from the unexpected co-generation. Hence, the heating

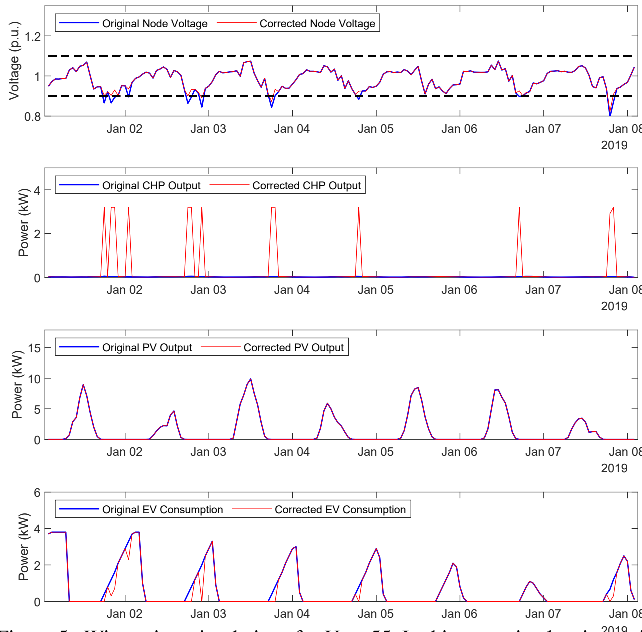

Figure 5. Winter time simulations for User 55. In this scenario also, importing from the grid is favored over turning on the mCHPs to meet the electricity demand.

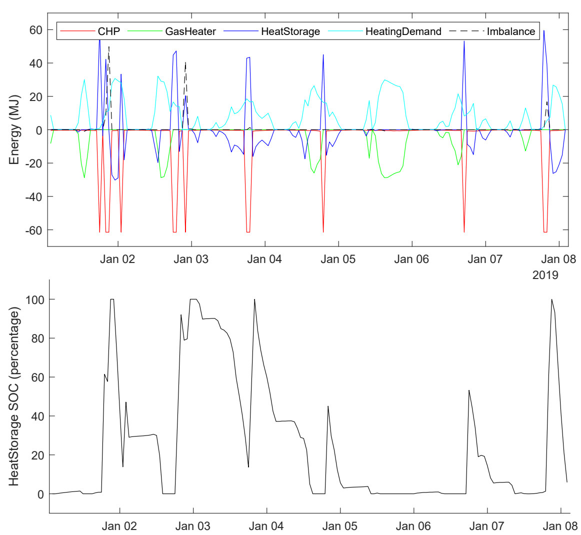

Figure 6. Heating installation of User 55 for the Scenario II (Winter simulation favouring the grid importing). mCHP peaks are absorbed by the heating buffer. In the case that the heating buffer is full, instances of excess production are visible as imbalances in the heating network.

buffer absorbs this excess production and replaces the gas heater at a later time. In the case that the buffer is full, the excess heat production results in an imbalance in the heating installation.

Scenario III: Summer week simulation (Local generation with mCHP favored)

Again in this scenario, over-voltage is the pressing issue. The notable difference here is in the schedule of the mCHPs which are turned on every night when the abundant PV generation is absent. During the day, it can be noted from Fig. 7 that curtailment of the PV systems helps in solving the nodal over-voltage issue. In the shoulder hours of the day, mCHPs turn off and on occasion, the EV increases charging to help bring the voltage level down. It can also be seen that PV curtailment drives the system to import from the grid as opposed to turn on the local mCHPs as this may only further increase the nodal voltage.

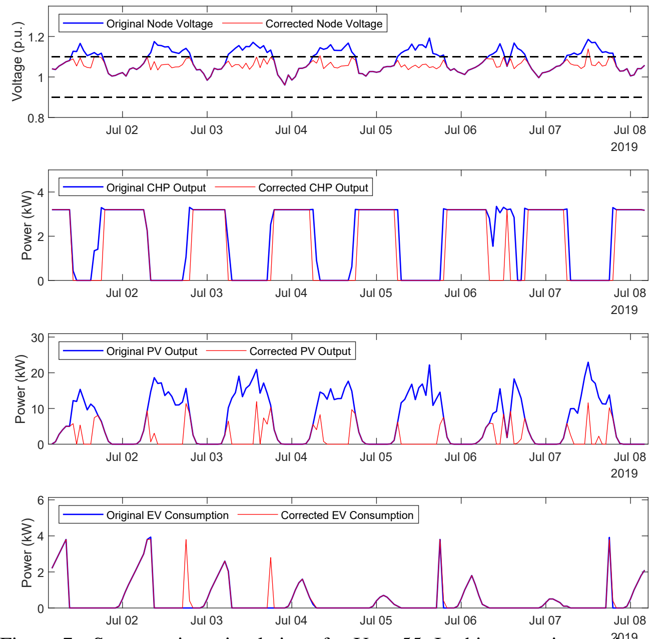

Figure 7. Summer time simulations for User 55. In this scenario, turning on the mCHPs is preferred importing from external grid. PVs are curtailed to solve over-voltage during the day. In the shoulder hours, mCHP is curtailed and occasionally, the plugged in EV helps.

Scenario IV: Winter week simulation (Local generation with mCHP favored)

The under-voltage effect of low PV and high electricity and heat demand as in Scenario II is offset in this case by increased mCHP generation. This results in occasional over-voltage issues when there is simultaneous PV generation as can be seen in Fig. 8. This problem is however handled by curtailing the mCHP generation. Notice that at the end of the week, an over-voltage issue was not solved even after the smart user provided flexibility, this is due to the fact that due to the low voltage magnitude level of the feeder.

B. Voltage Problem Solution Rate

The solution rate in each of the above-presented scenarios is defined as the percentage of times a voltage issue (over- and under-voltage) was successfully solved by the negotiations between the aggregator (requesting flexibility from the smart residential users) and the DSO across the entire network. As can be seen in Table II, the better performance of the aggregator-DSO negotiations are in summers, attributed to the availability of more flexible assets to contribute to solving the more prevalent problem (over-voltage). In order to increase the solution rate in winters, a higher capacity mCHP is required (coupled with a higher capacity buffer). However, over sizing such system might have a significantly financial impact on the residential users and thus might not be considered a feasible option.

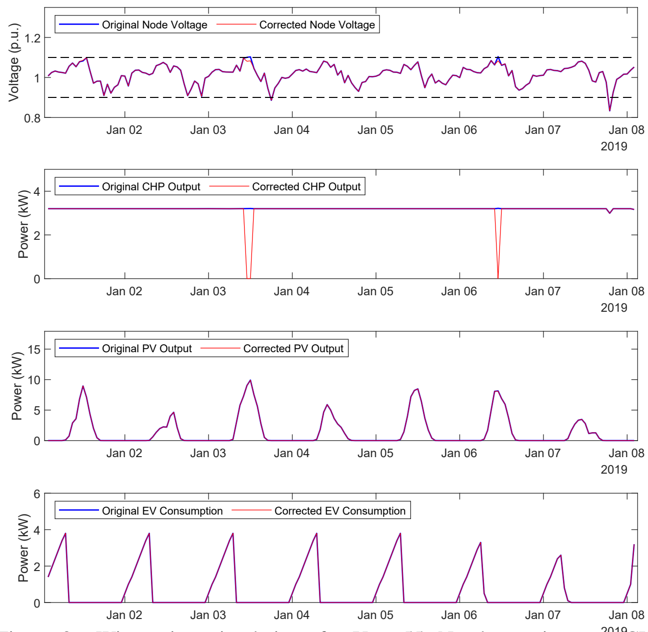

Figure 8. Winter time simulations for User 55. Nearly continuous mCHP generation compensates for voltage magnitude drops caused by low PV generation and high electricity and heat demand. Notice that the under-voltage issue at the end of the week goes unsolved as flexible devices are not in a state to help solve the issue.

Table II
SOLUTION RATE AND UNSOLVED PROBLEMS

Scenario	Solution Rate	Under-voltage Issues	Over-voltage Issues
Scenario I (Summer)	91.12%	14	60
Scenario II (Winter)	68.05%	194	0
Scenario III (Summer)	91.72%	10	68
Scenario IV (Winter)	75.15%	118	0

IV. CONCLUSION

In this paper, a co-simulation framework was presented. To maintain operational independence, the aggregator and the DSO are modeled as separate agents. Following a six-step algorithm, the DSO observe the state of the distribution network and request to the aggregator the provision of support services (i.e., voltage support). The aggregator can provide flexibility by requesting a set of smart (flexible) residential users to increase/decrease generation and/or consumption. Several simulated scenarios were presented and discussed, including results for winter and summer. According to the presented results, in summer, where over-voltage issues are expected due to the high PV penetration, a solution rate of 90% was estimated. For winter, in which under-voltage issues are more predominant, the solution rate was found to be around 70%. To increase the solution rate during winter, a higher nominal capacity for the mCHP or a higher capacity heat storage unit is required. Nevertheless, over-sizing such systems might have a financial impact that users and the aggregator must have to consider. These results validated the provision of voltage support services by smart residential users in a real (simulated) setting. Currently, real implementation of the CEM logic is in the development stage within the SEM Project. Results related to this final stage will be reported later. In future work the settlement between DSO, aggregator and consumers should be reviewed in context of the Dutch Energy regulation.

ACKNOWLEDGMENT

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