TIME-SERIES SIMULATIONS AND ASSESSMENT OF SMART GRID PLANNING OPTIONS OF DISTRIBUTION GRIDS

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ABSTRACT

We present a grid planning study for a part of the distribution grid of EKZ, the electric utility of the Canton of Zurich, Switzerland. Time-series simulations of a medium-voltage (MV) feeder comprising a low-voltage (LV) network are performed and an assessment of innovative versus conventional grid planning options is accomplished using the novel simulation platform DPG.sim (Distributed Prosumer and Grid Simulation). The impact of adding a large photovoltaic (PV) installation is being investigated. Several grid reinforcement options using conventional means or SmartGrid elements, such as curtailment, energy storage, and reactive power control, are simulated and evaluated with respect to their technical performance.

INTRODUCTION

Traditional distribution grid planning is usually based on a static load flow computation (snapshot) that takes into account the maximum coincident load to determine the grid infrastructure dimensioning. In the presence of Distributed Generation (DG), the maximum generation snapshot must also be considered and thus may impose stronger requirements than the load demand. If large amounts of wind and solar generation are present in the grid, this *worst case*-oriented dimensioning of lines and transformers leads to a highly over-dimensioned infrastructure and rare utilization of the full grid capacity. In the recent years, numerous *SmartGrid* approaches have been proposed that are able to actively influence electric load and generation profiles in order to improve grid operation. Several studies show that innovative operational measures, such as selective renewable energy curtailments, Demand Response, distributed storage, and reactive power control, can potentially make the transition to high shares of renewable energies more cost-effective by reducing grid upgrade costs [1], [2]. In order to reduce grid infrastructure costs by using innovative measures, such measures have to be considered explicitly at the grid planning stage. However, several investigations show that existing grid planning tools do not feature a realistic simulation of grid operation including *SmartGrid* elements which is required for cost-effective grid planning [3], [4].

In order to overcome this limitation, the simulation platform *DPG.sim* is developed and commercialized by the ETH Zurich spin-off Adaptricity [5]. The simulations constitute a valuable basis for the development of active network management operation strategies and the integration of active distribution network elements into grid planning decisions. *DPG.sim*'s unique feature in this respect is its versatile Prosumer modeling approach which allows to capture all relevant modeling details and operational constraints of controllable loads, distributed generation, and storage as well as SmartMeter communication infrastructure (see Figure 1).
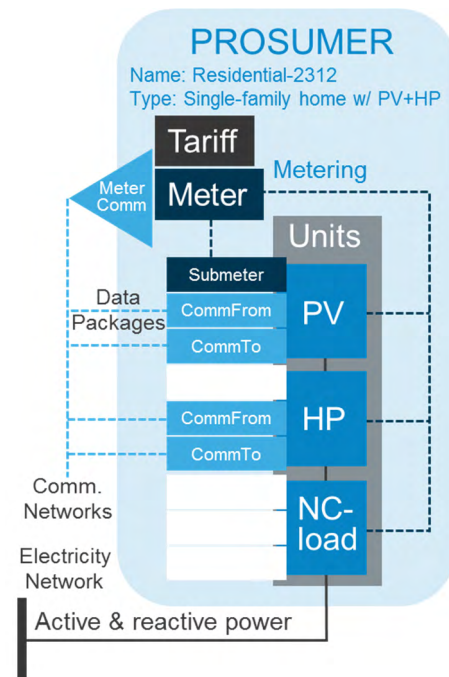

Figure 1: Prosumer modeling approach.

The main advantage of the simulation platform is its possibility to realistically simulate the operation of active distribution grids as well as the temporal evolution of generation, load, storage states, and operational control algorithms. Highly customizable views and data recording options provide deep simulation-based insights into a given distribution system. This helps decision makers to evaluate consequences and outcomes of integrating novel elements into their electricity grid.

In this paper, the capabilities of *DPG.sim* are illustrated for a realistic case study of a sub-urban distribution grid zone owned and operated by EKZ, the electric utility of the Canton of Zurich, Switzerland [7]. The grid zone includes an MV grid topology and several transformer station connections to LV grids. Real operational data estimations have been incorporated into the simulation setup. Based on this data, different scenario cases are simulated and assessed, including scenarios in which a large (PV) unit is deployed in the distribution grid zone. Conventional distribution grid planning options, i.e., the upgrade of electricity lines, are evaluated against alternatives such as a battery storage unit as well as an On-Load Tap Changer (OLTC) and reactive power control.

STUDIED GRID AND METHODOLOGY

The considered grid zone includes an MV grid (16 kV) topology comprising the sub-station connection to the overlay high-voltage (HV) grid (110 kV) and several transformer station connections to LV grids (0.4 kV) as well as one full LV grid topology for which yearly smart metering measurement data is available. Real operational data, i.e., fine-grained load measurements for some parts of the benchmark grid as well as coarser load measurements and estimations for other parts, and auxiliary structural information of larger load units are incorporated into the simulation setup.

The distribution grid section under investigation is composed of the MV feeder (Dietikon East) emanating from EKZ's substation Schlieren. Directly connected to the feeder are a large data center drawing an active power of 2–3 MW and three low-voltage transformer stations. The LV grid behind the transformer station Luberzen (rated with 430 kVA) is modeled in detail while the other two transformer stations (rated with 430 kVA and 1000 kVA) are represented by lumped load time series. A map of the distribution grid from the substation Schlieren to the transformer station Luberzen is shown in Figure 2.
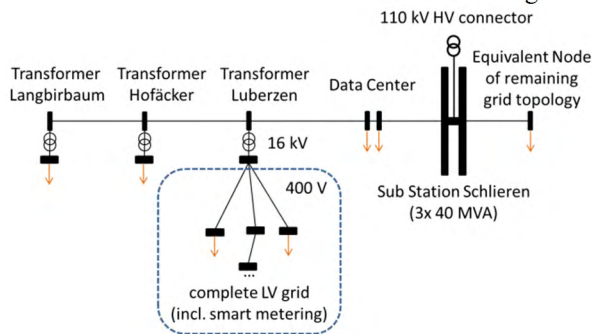

Figure 2: Benchmark distribution grid topology (EKZ).

A full-year simulation was not feasible due to lack of available data. Thus, we constructed a simulation base case for the time period of Jan.–Sept. 2013 (9 months).

Utilized Data

We use the following data for base case parameterization:

Item	Measured Data
Substation Schlieren	Voltage V, apparent power S, power factor $\cos(\varphi)$, 10-min sampling (2013)
Feeder *Dietikon East*	Feeder current I, 15-min sampling (2013)
Data center	Active energy E_P, 15-min sampling (2013)
TS Luberzen	SmartMeter customers: Active energy E_P, 15-min sampling (Jan–Sept 2013) Non-SmartMeter customers: Yearly active energy E_P consumed (separated in high/low tariff time slots), 2011–13
Other TS	No measurement data available

Data Reconstruction Approach

The following data was not available and had to be reconstructed by a number of methods:

Active/reactive power of considered MV feeder

From a current measurement at the feeder and the voltage measurement at the substation, we calculated the apparent power. We assumed the aggregate power factor of the substation to be equal to the power factor on the feeder and thus could calculate the active and reactive power.

Active power load on the transformer Luberzen

We used one available week of active power measurements $P_{Luberzen}$ at the transformer and the active power of the MV feeder P_{Feeder} to calculate the ratio $(P_{Luberzen} - P_{Datacenter})/P_{Feeder}$. We then used a linear regression to calculate $P_{Luberzen}$ for the full 9 months.

Customers without a SmartMeter

For the customers without a SmartMeter, we used a stochastic sampling approach in which individual consumption values were drawn from an exponential distribution, scaled with the yearly consumption of the respective customer and fitted against the aggregate active power curve at the transformer Luberzen. Figure 3 depicts an exemplary time series in 15-minute resolution. Future work will involve more detailed load consumption models such as [8].
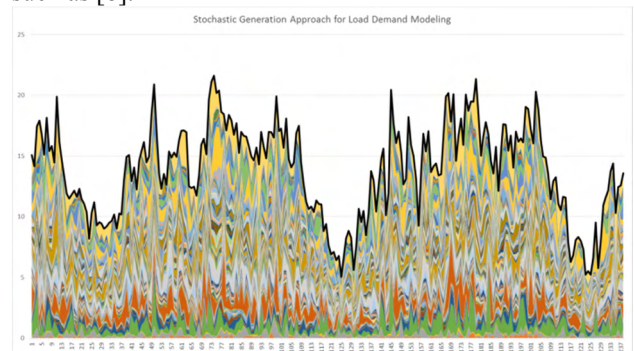

Figure 3: Stochastic sampling of customer load profiles.

BASE CASE SIMULATION

Time-series simulations in *DPG.sim* for the above described distribution grid section under investigation, i.e., the MV feeder Dietikon East emanating from the substation Schlieren, are performed for the full 9-month time-period. We evaluate the voltage quality according to the $\pm 10\%$ criterion stipulated in EN 50160 [6].

Based on the measured, reconstructed, and estimated grid data time-series, the following grid situation arises for a representative week in June (see Figure 4). While the steady load demand profile of the data center makes up the largest share of overall load demand, the load profiles of the three transformer stations serving the mixed commercial and residential area exhibit a typical daily load pattern with pronounced evening hour peaks.
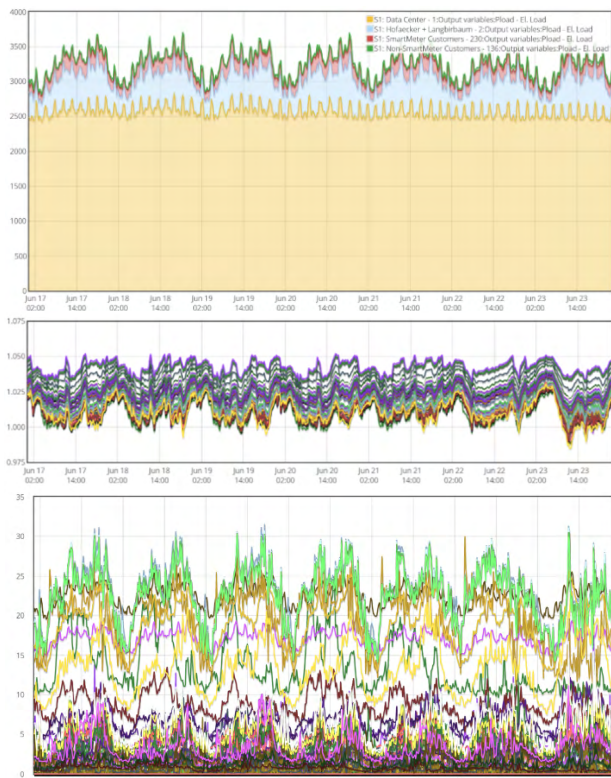
Figure 4: Base case simulation (June 2013). Top: aggregated load demand curve [kW], middle: voltages at MV/LV buses [pu], bottom: MV/LV line loadings [%].
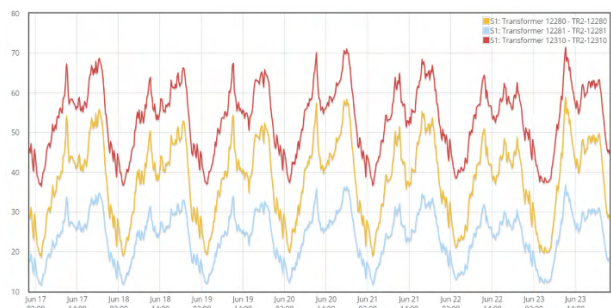

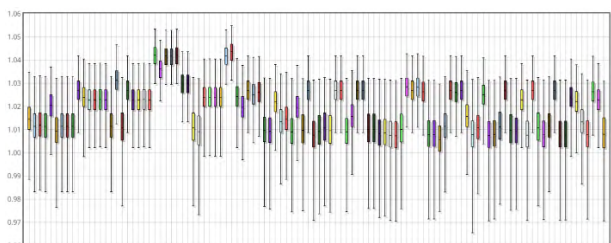*Figure 5: Transformer loading [%] (June 2013).*

Figure 6: Voltage level box plots [pu] (Jan.–Sept. 2013).

The loading level of the transformer Luberzen (see Figure 5, top curve, plotted in red) stays below 75% during the entire week. In winter, when the load is generally higher, they approach 100%.

The voltage levels of the MV and LV buses exhibit significant deviations over the course of the 9-month simulation period as shown by a box plot (see Figure 6; boxes denote quartiles, whiskers the minimum and maximum for each bus).

LARGE PV INSTALLATION IMPACTS AND MITIGATION OPTIONS

In order to evaluate the impacts of integrating additional PV capacities, we add to the base case scenario a 280 kW PV unit into the low voltage grid below the station Luberzen (distance of 300 m from PV unit to transformer).

Base Case with PV Installation

This relatively sizeable PV unit, compared to the peak load demand of the transformer station Luberzen (less than 400 kW), has significant impacts on the LV grid. Significant voltage level rise (above 1.10 pu) and line loading peaks (close to 70 – 80%) are induced by the PV in-feed on sunny days as shown for a representative summer week in Figure 7. This leads to a violation of the permissible voltage corridor of ± 10%. The loading level of the Luberzen transformer is decreased on average but subjected to more fluctuations due to the PV in-feed.
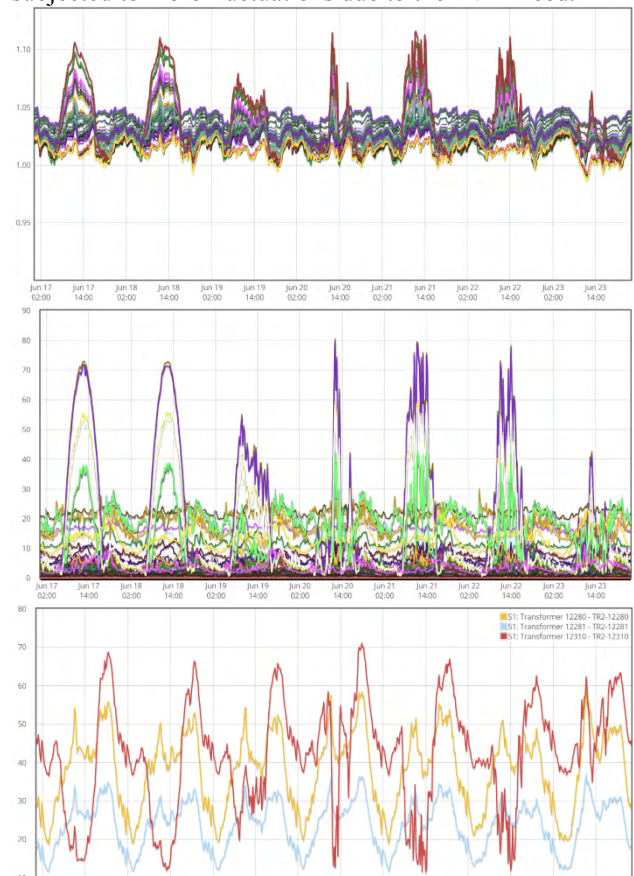

Figure 7: PV case time simulation (June 2013). Top: voltages at MV/LV buses [pu], middle: MV/LV line loadings [%], bottom: MV/LV line loadings [%].

Conventional Grid Upgrade

The conventional grid reinforcement would in this case be to replace all lines from the PV in-feed point to the transformer by underground cables with larger radius (change from 3x95 to 3x150). In comparison to the base case, the voltage rise is contained below the threshold of 1.10 pu (see Figure 8).
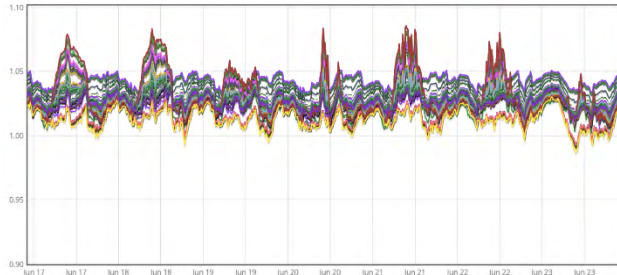

Figure 8: Voltages at MV/LV buses [pu] (June 2013).

PV Power In-Feed Curtailment

An effective alternative to line reinforcement is the controlled curtailment of available PV power in-feed. In many countries this has become the state-of-the-art option for coping with PV in-feed overflow in case all other available means fail. Here, PV in-feed is curtailed to 60% of $P_{installed}$ when the bus voltage is above 1.10 pu. The PV curtailment pattern for a representative summer week is shown in Figure 9. Over the course of the 9-month simulation period altogether 9.9 MWh of the available PV production (242.1 MWh) would need to be curtailed, which corresponds to 4.1% of the PV production. Extrapolating this to the full year by counting the first three months twice, one obtains 10.6 MWh curtailed of 270.1 MWh available (3.8%).
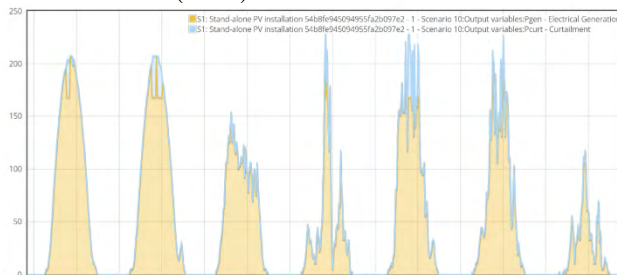

Figure 9: PV in-feed curtailment [kW] (June 2013).

Again, the voltage rise does not exceed the maximum acceptable voltage level of 1.10 pu (see Figure 10).
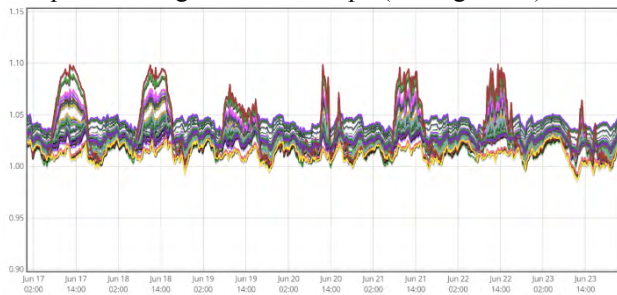

Figure 10: Voltages at MV/LV buses [pu] (June 2013).

Battery Storage Utilization

Absorbing surplus PV power in-feed by a battery energy storage system (BESS) is another effective means for grid integration. Here, a BESS system with a power rating of 100 kW, an energy rating of 600 kWh, and charging and discharging efficiencies of η = 0.9 are employed. The battery control is a simple hysteresis, i.e., charging whenever the bus voltage level rises above 1.09 pu and discharging when the bus voltage falls below 1.04 pu.

As can be seen in Figure 11, the BESS system effectively limits the voltage levels in the LV grid within allowable ranges. The BESS charging/discharging patterns are shown in Figure 12. Altogether, 32.4 MWh are cycled in the battery system, causing battery losses of 6.2 MWh in the 9-month period. This is equal to 2.5% of the available PV in-feed and roughly 62% of the energetic losses incurred by the curtailment strategy.

These values can also be approximately extrapolated to the full year by counting the first three months of the year twice. This yields a cycled energy of 34.7 MWh and a loss of 6.6 MWh, amounting to 2.4% of the available PV energy. As in the case of in-feed curtailment, this slightly lower value is caused by lower PV peaks in winter time.
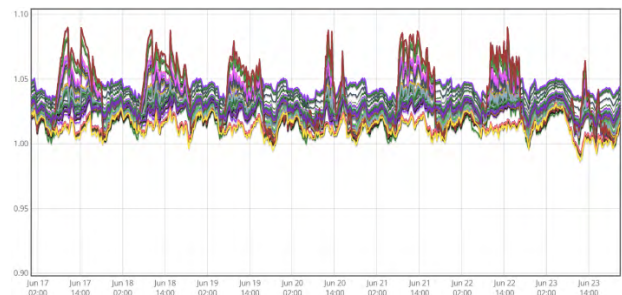

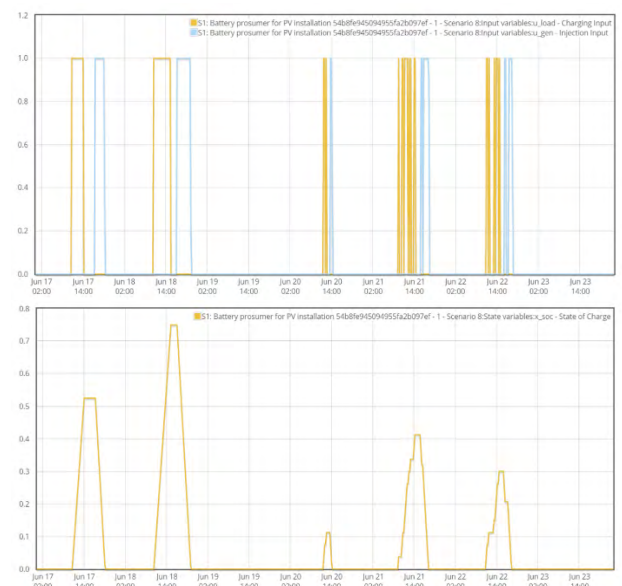*Figure 11: Voltages at MV/LV buses [pu] (June 2013).*

Figure 12: BESS operation patterns (June 2013). Top: charging/discharging phases [0, 1], bottom: State-of-Charge evolution [pu] of BESS unit).

Low-Voltage On-Load Tap Changer (OLTC)

We also consider a LV transformer station that can dynamically adjust voltage levels via on-load tap changes (OLTC). The voltage measurement takes place at the location of the PV installation with a dead-band of 1.6 pu and a tap size of 1.5 pu. As a result, voltage levels are kept below 1.06 pu. However, tap change actions can, at times, also lead to severe under-voltages at other buses, close to the formally acceptable minimum of 0.90 pu (see Figure 13). Considering the significant under-voltages as such, as well as the rapid voltage changes during the day, an OLTC alone does not appear to be a favorable means to mitigate the voltage problems caused by the PV installation.
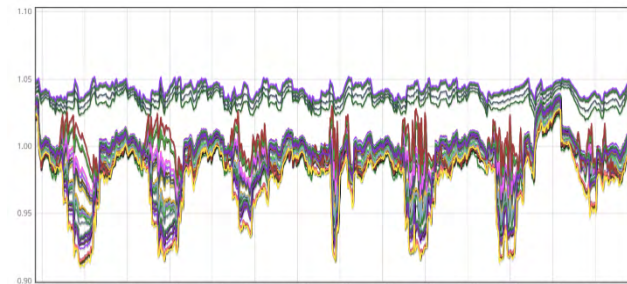

Figure 13: Voltages at MV/LV buses [pu] (June 2013).

Reactive Power Control

As a last measure reactive power control, using a fixed ratio of $\cos(\varphi) = 0.90$ is evaluated. Again, voltage levels can be kept at bay (see Figure 14). However, an unintended side effect is the noticeable rise in line loading as is illustrated in Figure 15 (increase of the maximum by over 10 percent-points). This leads to overproportionally higher losses, and a slightly larger PV installation could thus overload the installed LV cable.
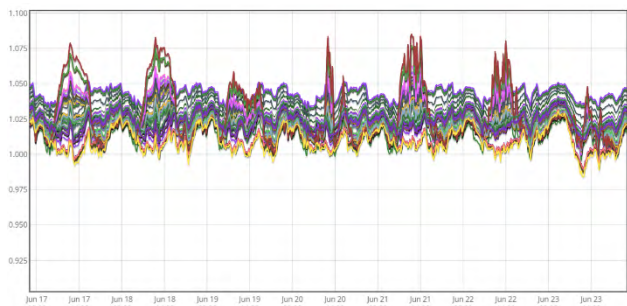

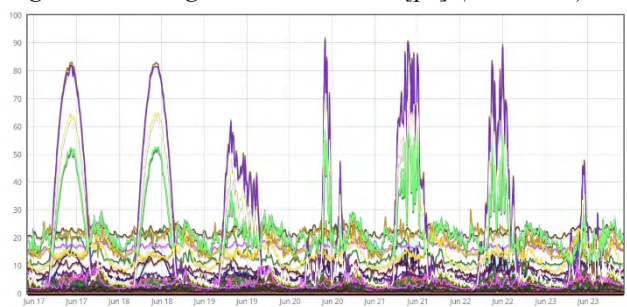*Figure 14: Voltages at MV/LV buses [pu] (June 2013).*

Figure 15: MV/LV line loadings [%] (June 2013).

CONCLUSION AND OUTLOOK

The presented study shows the nowadays much larger and more complex solution space for distribution grid planning strategies for accommodating large PV shares. It also showcases the unintended side-effects that the mitigation of over-voltage events can have, namely under-voltage events at other buses due to OLTCs and increased line loading due to reactive power control.

This underpins the need for novel grid simulation and planning tools that allow the evaluation of advantages and disadvantages of conventional and, in particular, novel *SmartGrid* reinforcement strategies.

In this respect, *DPG.sim* overcomes today's lack of industry-grade simulation, analysis, and optimization software for *active distribution grids*. Forthcoming publications will focus on other upcoming challenges of distribution grid operation such as electric vehicles (EVs) as well as the incorporation of SmartMeter data into grid simulations and with it the larger topic of SmartMeter data analytics.

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