Mitigating the impact of distributed PV in a low-voltage grid using electricity tariffs

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***Abstract*—A high share of distributed photovoltaic (PV) generation in low-voltage networks may lead to over-voltage, and line/transformer overloading. To mitigate these issues, we investigate how advanced electricity tariffs could ensure safe grid operation while enabling building owners to recover their investment in a PV and storage system. We show that dynamic volumetric electricity prices trigger economic opportunities for large investments in PV and battery capacity but lead to more stress on the grid while capacity and block rate tariffs mitigate over-voltage and decrease line loading issues. However, block rate tariffs significantly decrease the optimal PV installation size.**

***Index Terms*—Grid stability, Mixed-integer linear programming, Electricity tariff design, Cost optimization, Photovoltaic**

I. Introduction

Significant investments in photovoltaic (PV) systems are expected in the coming years due to increasing economic interest and to their contribution to clean energy generation. Reaching the full PV potential in urban environments could lead to a system in which a significant fraction of the energy should be curtailed in order to cope with the network operating constraints. Centralized control of PV curtailment by the distribution system operator (DSO) is a promising solution but could raise concerns about intrusiveness and discourage (potential) prosumers. An alternative approach is to propose novel electricity pricing mechanisms that help to mitigate the impact of distributed storage and PV systems on the grid while allowing building owners to make profitable investments. The purpose of this work is to evaluate which advanced electricity tariff creates the best trade-off between these two objectives.

The impact of the high penetration of distributed renewable energy sources was investigated in [1] where it is shown how the network topology and the way distributed PV is geographically located along the feeder have a strong impact on the voltage profile. Considering the deployment of net-zero-energy buildings, Arboleya et al. [2] studied the impact of various PV penetration levels on the voltage profile of a low-voltage grid. The authors of this study assumed that each building minimizes its energy bill, i.e. no coordination between building is present, and argued that the network will have to face such uncoordinated operation for years to come. Conversely, Hidalgo-Rodriguez et al. [3] studied two micro-grid coordinated control strategies and one uncoordinated control strategy to achieve network balancing. Further in this direction, Haschemipour et al. [4] proposed a control strategy for PV and battery systems to achieve voltage regulation, using a multi-objective optimization. In this work, however, the grid exchange cost, i.e. the profitability for the building owner, is not considered as an objective function. The opposite approach of Sani Hassan [5] is to optimize the sizing and operation of an energy system on typical days and to study the impact on the voltage profile under various technological scenarios. The latter apply only to a single multi-family building while the load of the other bus remains identical. The work of Wang et al. [6] proposes to integrate the revenue from frequency control ancillary services and reliability services into the objective function. The model quantifies the value of such services.
The previously mentioned literature does not consider the use of advanced tariff structures nor their impact on the system configurations. Schreiber et al. [7] proposed electricity tariffs and evaluate their impact on the grid requirements for two different buildings under two technological scenarios. Deetjen et al. [8] introduced an integrated convex formulation for equipment sizing and optimal control for a central utility plant in order to better integrate the surrounding rooftop PV. The authors considered time-of-use electricity pricing to be the best solution for providing flexibility services, absorbing the excess PV generation. More tariff scenarios are considered in the study of Ren [9], which specially focuses on the profitability of PV and battery system for owners. This analysis describes how capacity tariffs can lower the revenue of the owners because PV generation cannot efficiently reduce peak demand. The previously mentioned studies are missing a few considerations, such as accounting for more than a single building, allowing the PV and battery size to adapt to the scenarios, or integrating their assessment of building performance and network impact. There is thus a lack of literature considering the synergies between mitigating the network impact of PV systems and enabling profitable investment in PV-battery systems.

In this work, we investigate the effect of five different tariff scenarios, on network operation when optimizing both the design and operation of all buildings connected to that network,

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using a methodology developed in [10]. The scenarios consider pure volumetric electricity tariffs, a mix of volumetric and capacity-based tariffs, or a block rate tariff. The optimization is run for a set of buildings in a sub-network of Rolle (Switzerland). The buildings' characteristics are known from a geographical information system. The resulting loads and generations at each injection point allow for solving the power flow equations over a full year to extract the distribution of the voltage level and line loading. Finally, these distributions are compared with a reference case to assess the effect of the selected tariffs.

II. Methodology

The methodology to assess the impact of distributed PV on a low-voltage grid consists of a two steps process, which is sequentially repeated for each tariff scenario. First, the optimal design and operation of each building energy system are individually optimized using a mixed-integer linear programming (MILP) formulation under a particular tariff scenario. After each individual building optimization, the performance of the considered building is assessed. Once all building have been optimized, the load flow problem is solved for a distribution grid using the building-grid power exchanges resulting from the first step. Finally, the impact on the grid is assessed by evaluating dedicated grid performance metrics. The workflow of this process is illustrated in Fig. 1. It can be noted that the first scenario ($s = 1$) serves as reference scenario. The tariff parameters of the other scenarios are calibrated such that the revenue of the DSO stays as close as possible to the revenue of the reference case.

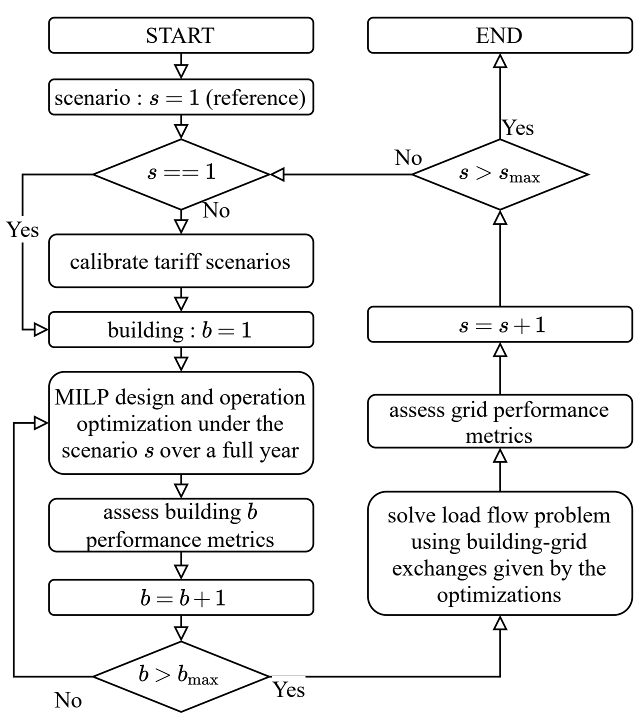


Fig. 1. Process workflow.

The following briefly summarizes the buildings' optimization problem, defines the performance metrics for the design and operation, and presents the performance metrics from the grid perspective.

A. PV-battery optimal sizing and operation

The PV and battery sizing and operation are optimized for each building to minimize the total cost of ownership, i.e. the sum of the annualized investment, maintenance and operational cost, as described in (1), subject to a power balance constraint (2). By definition, the optimization problem relies on the assumption that an exact forecast of both the PV generation and the electrical load is provided. The impact of forecast errors and energy managers' performance is outside the scope of this study. The optimization model's input and output is graphically summarized in Fig. 2. The formulation of the optimization is written as:

$$\text{minimize } \text{CAPEX}(P_{\text{CAP}}^{\text{PV}}, E_{\text{CAP}}^{\text{BAT}}) + \text{OPEX}(P_t^{\text{IMP}}, P_t^{\text{EXP}}) \quad (1)$$

$$\text{subject to } P_t^{\text{IMP}} - P_t^{\text{EXP}} - P_t^{\text{CHA}} + P_t^{\text{DIS}} - P_t^{\text{CUR}} + P_t^{\text{PV}} = P_t^{\text{LOAD}} \quad \forall t \in T \quad (2)$$

where CAPEX, the annualized investment and maintenance costs, are a function of the installed PV capacity $P_{\text{CAP}}^{\text{PV}}$ and the battery size $E_{\text{BAT}}^{\text{CAP}}$, OPEX are the operating costs and are a function of the grid exchange power $P_t^{\text{IMP,EXP}}$. $P_t^{\text{CHA,DIS}}$ are the battery charging and discharging power respectively, P_t^{CUR} is the power actively curtailed from the PV generation P_t^{PV}, and P_t^{LOAD} is the uncontrollable electric load of the building.

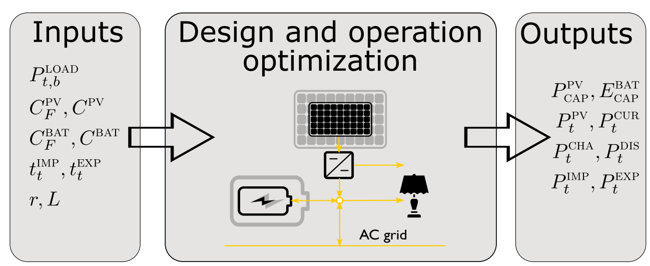


Fig. 2. Optimization inputs and outputs.

The operational costs are simply the cost of exchanging energy or power with the grid (3a). Three kinds of grid exchange costs are modeled: Volumetric (3b) in which costs are proportional to the exchanged energy, capacity-based (3c) in which the cost is proportional to the maximum monthly exchanged power, and a block rate (3d) in which the marginal cost of buying/selling energy depends on the power level at which it is exchanged. Mathematically, this can be written as:

$$\text{Op. cost} \qquad \text{OPEX} = \sum_{p \in \text{vol,cap,block}} \text{OX}_p \quad (3a)$$

$$\text{Volumetric} \qquad \text{OX}_{\text{vol}} = \sum_{t=1}^{T} [P_t^{\text{IMP}} \cdot t_t^{\text{IMP}} - P_t^{\text{EXP}} \cdot t_t^{\text{EXP}}] \cdot \text{TS}_t \quad (3b)$$

$$\text{Capacity} \quad \text{OX}_{\text{cap}} = \sum_{m=1}^{M} P_m^{\text{MAX}} \cdot t^{\text{MAX}} \tag{3c}$$

$$\text{Block rate} \quad \text{OX}_{\text{block}} = \sum_{t=1}^{T} \max_{k=1\ldots K} \left(P_t^{\text{IMP}} \cdot a_k^{\text{IMP}} \cdot \text{TS}_t + b_k^{\text{IMP}}\right)$$
$$- \sum_{t=1}^{T} \min_{k=1\ldots K} \left(P_t^{\text{EXP}} \cdot a_k^{\text{EXP}} \cdot \text{TS}_t + b_k^{\text{EXP}}\right) \tag{3d}$$

where $t_t^{\text{IMP}}, t_t^{\text{EXP}}$ are the volumetric import and export tariff respectively (in CHF/kWh), TS_t is the simulation time-step, the maximum power for month m, P_m^{MAX}, is calculated by requiring that both the import and the export power be smaller than this variable, the pairs of coefficients $a_k^{\text{IMP}}, b_k^{\text{IMP}}$ and $a_k^{\text{EXP}}, b_k^{\text{EXP}}$ are the component of the piece-wise linear cost functions of buying, respectively selling energy, a representing the slope, or marginal cost,b the corresponding intercept term and simply ensure the continuity of the cost function (see the buy cost and sell cost curve in Fig. 4). All these variables are parameters of the building optimization problems. Only $P_{\text{CAP}}^{\text{PV}}$, $E_{\text{CAP}}^{\text{BAT}}$, P_t^{IMP} and P_t^{EXP} are the optimization decision variables. Variables P_t^{CHA}, P_t^{DIS}, P_t^{CUR}, P_t^{PV} and P_m^{MAX} are intermediate decision variables constraint by the decision variables and parameters. The reader should refer to [10] for the modeling details of this optimization problem.

B. Performance metrics

These metrics aim to assess the system design's reaction, in terms of equipment size and operation, and the network's reaction, in terms of voltage profile and line loading, when changing the electricity pricing structure. From a building design perspective, the PV hosting ratio, PV host (4a), is the ratio between the installed PV capacity and the maximum PV potential capacity of the building. The PV penetration ratio, PV penetration (4b), compares the energy generated by the PV arrays with the annual energy demand. The battery autonomy ratio, BAT auto (4c), corresponds to the ratio between the battery capacity and the mean daily energy demand of the building. This metric can be understood as the fraction of a day that can be covered by the battery in the event of a blackout. From an operation perspective, the PV curtailement ratio, PV cur (4d), is the fraction of the energy that is curtailed from the PV generation. The self-sufficiency SS (4i) is the fraction of the energy demand that is self-covered by the PV-battery system. The definition of (4i) is derived from [11]. To assess how the buildings interact with the grid, we defined in [10] a grid usage ratio, GU IMP,EXP (4e), as the ratio between the maximum withdrawn/injected power and the maximum load. Finally, from an economic perspective, the discounted payback period, DPP (4g), (time to recover the investment) is of crucial interest to evaluate the profitability of the proposed economic framework. The levelized cost of energy demand (LCOE)(4h) can be compared with the import tariffs of each scenario and provide an indication of the price of one unit of energy that is consumed under the optimized system. These indicators are defined for each building as follows (the use of a subscript b has been omitted for better readability):

$$\text{PV host} = P_{\text{CAP}}^{\text{PV}} / P_{\text{CAP,max}}^{\text{PV}} \tag{4a}$$

$$\text{PV penetration} = \sum_t P_t^{\text{PV}} / \sum_t P_t^{\text{LOAD}} \tag{4b}$$

$$\text{BAT auto} = \frac{E_{\text{CAP}}^{\text{BAT}}}{\text{mean daily consumption}} \tag{4c}$$

$$\text{PV cur} = \sum_t P_t^{\text{CUR}} / \sum_t P_t^{\text{PV}} \tag{4d}$$

$$\text{GU IMP,EXP} = \max_t (P_t^{\text{IMP,EXP}}) / \max_t (P_t^{\text{LOAD}}) \tag{4e}$$

$$\text{NPV} = \sum_t \text{CF}_t / (1+r)^t \tag{4f}$$

$$\text{DPP} = T \text{ such as } \frac{\sum_{t=1}^{T} \text{CF}_t - \text{OPEX}_t^0}{(1+r)^t} = 0 \tag{4g}$$

$$\text{LCOE} = \frac{\text{NPV}}{\sum_i^L \frac{(\cdot \sum_t P_t^{\text{LOAD}} \cdot TS_t)}{(1+r)^i}} \tag{4h}$$

$$\text{SS} = \frac{\sum_t \min(P_t^{\text{LOAD}}, P_t^{\text{EXP}} + P_t^{\text{LOAD}} - P_t^{\text{IMP}})}{\sum_t P_t^{\text{LOAD}}} \tag{4i}$$

where CF_t is the net cash flow (investment + maintenance cost + operational cost, including battery replacement) at time t and OPEX_t^0 is the original operating cost without the investment in the PV and battery.

The resolution of the power-flow equations allows for extracting the voltage (in per unit, pu) at every node of the network and the current flowing through every line. Given the lines' properties, in particular the maximum allowable current, a representative metric for grid congestion is the line loading level. We consider separately the situation when the bus voltage at an injection point is above 1 pu and when it is below 1 pu, and use the 95$^{\text{th}}$ percentile of the bus voltage deviation. This allows us to distinguish when there is a local excess of energy from when there is a local deficit of energy. Finally, one of the key issues for the high penetration of distributed stochastic generators is the reverse-power flow occurring at the medium- to low-voltage transformer. For this reason, the load duration curve enables assessing the requirement in terms of power that has to flow into and out of the low-voltage grid.

III. CASE STUDY

The methodology is applied to a case study in Rolle (Switzerland) where a low-voltage distribution grid has been modeled (Fig. 3). The grid hosts 41 buildings. The properties of each building are known thanks to publicly available geographical information system[1]. The annual energy demand for each meter in the grid was provided, allowing us to match the meters with real smart-meter measurements (from similar buildings) and allocate smart-meter time-series to each meter. The roof's surface area, azimuth, and tilt are known for each building. With this information, the maximum potential PV hosting capacity of each roof and then of each building could be calculated. Fig. 3 shows this maximum PV capacity and the building's annual energy demand.

[1] https://www.asitvd.ch/

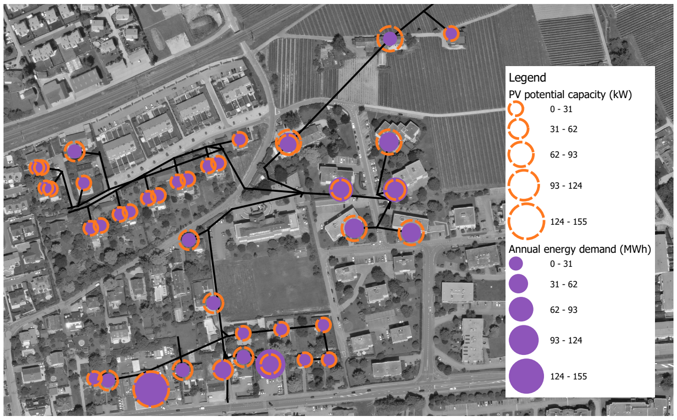


Fig. 3. A map of the considered low-voltage grid (black lines). The circle diameters are scaled according to the PV potential capacity (orange) and annual energy demand (violet). The relative circle diameter gives an indication on the potential PV penetration considering an annual irradiation of 1000 h.

Five tariff scenarios, and their corresponding coefficient from (3b), (3c), (3d), are defined in Table I. The first three scenarios consider volumetric tariffs in which the costs/revenues are proportional to the exchanged energy according to a given energy tariff. The first scenario is a reference tariff that is constant throughout the day. The second scenario, called "solar", promotes consumption when solar irradiance is higher by setting a low energy rate during the time period 11 h-15 h. The third scenario mirrors the spot market price (specifically the intraday continous price from the EPEX market data[2]). The fourth scenario is a mix of a volumetric and capacity-based tariffs, for which the cost is proportional to the monthly maximum power exchanged with the grid and the energy consumed from the grid, while the revenue is proportional to the energy injected into the grid. The fifth scenario considers a block rate tariff, in which the cost/revenue is proportional to the energy exchanged with the grid, but the energy cost depends on the power level at which the energy is exchanged. For each scenario, the coefficients of (3b), (3c) and (3d) that do not appear in Table I are equal to zero.

In order to not unintentionally incentive or penalize PV installation, or change the value of a unit of electric energy, the tariffs (except the reference one) have been calibrated before running the building optimization (reminding Fig. 1). The calibration aims here at keeping the DSO revenues (from selling energy minus cost of buying exported power) of the network remains as close as possible to the net profit of the reference scenario, under the hypothesis that all buildings will behave exactly the same way as under the reference scenario. With this in mind, the values of the coefficient in Table I have been found empirically.

The PV and battery price levels have been set according to the reference year 2025. The price projections have been extracted from the IRENA report [12] and calibrated for the Swiss price levels provided in a recent market study [13] using the empirical model presented in [10]. The resulting PV and battery cost function is decomposed into a fixed and a linear component, $C_F^{\mathrm{PV,BAT}}$ and $C^{\mathrm{PV,BAT}}$ respectively. These linear cost functions are annualized and used along with the PV yearly maintenance cost and and battery lifetime in 1. All parameters of the problem, except the tariffs' parameters, are provided in

[2]EPEX price for 2018 https://www.epexspot.com/en/market-data/intradaycontinuous/intraday-table/-/CH

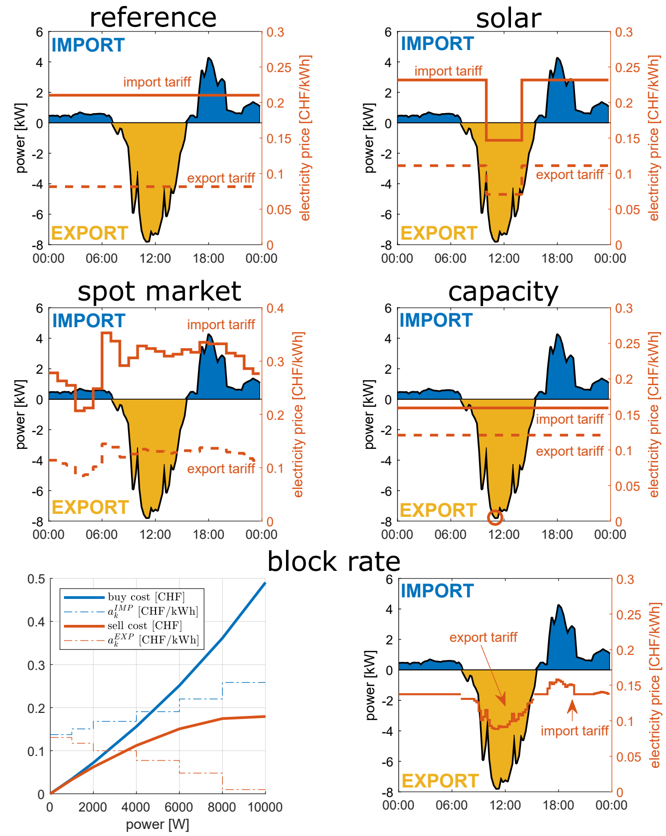


Fig. 4. Scenario preview for a typical day with PV generation.

TABLE I
TARIFF SCENARIOS

Scenario	Description	Tariff (CHF cts/kWh)	
reference	t_t^{IMP}:	21.02	
	t_t^{EXP}:	8.16	
solar	$t^{\mathrm{IMP}}_{t\in 11h:15h}$:	14.68	
	$t^{\mathrm{EXP}}_{t\in 11h:15h}$:	7.07	
	$t^{\mathrm{IMP}}_{t\notin 11h:15h}$:	23.17	
	$t^{\mathrm{EXP}}_{t\notin 11h:15h}$:	11.12	
spot market	t_t^{IMP}:	EPEX*3.9468	
	t_t^{EXP}:	EPEX*1.604	
capacity	t_t^{IMP}:	15.91	
	t_t^{EXP}:	12.09	
	t^{MAX}:	5.02 CHF/kW/month	
block rate	Power (kW)	a_k^{IMP}	a_k^{EXP}
	0 to 1	13.72	13.07
	1 to 2	15.06	11.73
	2 to 4	16.80	9.99
	4 to 6	19.07	7.73
	6 to 8	22.01	4.79
	8 to 10	25.83	0.96

Table II.

TABLE II
PARAMETERS

	Parameter	Value	Description
GENERAL	T	35040	number of time steps
	M	12	number of months
	TS	900 s	time steps
	L	25 years	system lifetime
	r	3%	discount rate
PV	$P^{PV}_{CAP,max,b}$	*	maximum building PV capacity
	C^{PV}_{F}	10049 CHF	PV fixed cost **
	C^{PV}	1.05 CHF/W	PV specific costs **
BAT	C^{BAT}	229 CHF/kWh	battery specific cost **
	C^{BAT}_{F}	0 CHF	battery fixed cost **

* data from the geographical information system
** same value for all buildings

IV. RESULTS AND DISCUSSION

The optimizations of the 41 buildings were performed on an Intel(R) Xeon(R) CPU E5-2630 v3 @ 2.40 GHz processor with 8 Cores and 32 GB of RAM using GUROBI [14] to solve the mixed-integer-linear problem. The load flow problems were then solved for each time step with a resolution of 15 min using PANDAPOWER [15]. The computation time for the building optimizations depends very much on the scenario as reported in Table III. In this table, the total column is the sum of the optimization across the 41 buildings' optimizations. The computation time required to solve the load flow problem is negligible compared to the total optimization time.

TABLE III
COMPUTATION TIME STATISTICS

Scenario	Building optimization min [min]	max [min]	median [min]	total [h]	Load flow [min]
reference	3.7	57.3	13.6	11.8	6.6
solar	2.4	41.6	11.3	8.8	6.6
spot market	2.4	43.6	13.1	10.2	6.8
capacity	31.8	147.2	90.4	60.6	6.6
block rate	43.5	321.2	103.9	81.2	6.6

A. Design and operation of the PV-battery energy systems

The resulting designs are pictured in Fig. 5. In all scenarios, except the block rate tariff, almost all the roofs are covered with PV leading to a PV hosting value close to one. The block rate scenario however limits the penetration of PV with a PV hosting of ca. 0.5. The reason is the nature of the block rate that favor smaller PV installation, because the marginal export revenue decreases with increasing exported power. Regarding battery size, investment in such technology is driven by economic opportunities, namely by variations in the electricity price (solar and spot market tariff scenarios) or by a strong incentive to limit the exchanged power (capacity tariff scenario). Although this last aspect is also present in the block rate scenario, the incentive is lower, leading to lower relative battery size. In terms of grid usage, only the capacity tariff and block rate tariff scenarios provide a clear stimulus to reduce the maximum power exchanged with the grid. The spot market and solar tariff scenarios, due to the volatility of electricity prices, tend to increase the power injected or withdrawn from the grid. On the economic side, the discounted payback periods are similar, ranging from 14 to 23 years for all scenarios. The median is, however, higher for the block rate tariff, 21 years against 19 years for the other scenarios.

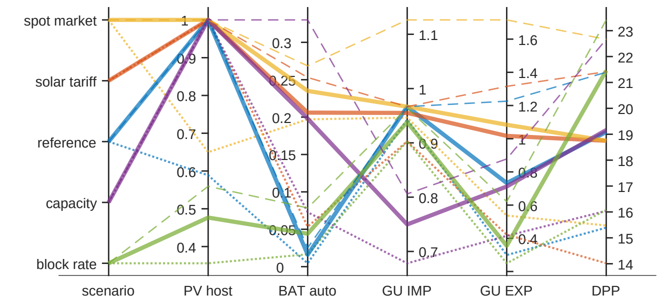


Fig. 5. PV hosting ratio, battery autonomy, grid usage ratio (import/export) and discounted pay back period for all scenarios. Metrics are defined in (4). Solid lines are the median, dashed lines are the 75th percentile, and dotted lines are the 25th percentile.

The relative size of the battery does not scale linearly with PV penetration, as depicted in Fig. 6a, except for the dynamic volumetric tariffs (spot market and solar). For the capacity and block rate tariffs, low PV penetration, underlying a small PV production, i.e. small PV capacity, compared to the energy demand, tends to increase the battery autonomy ratio in order to limit the imported power. Conversely, at high PV penetration, the battery autonomy tends to decrease for the capacity and block rate tariffs. For the first case, the role of the battery to cut injection peaks is replaced by the curtailment of the PV generation (Fig. 7). As curtailing is free (it is not imposed but it results from the optimization of the system operation), there is no need to invest in batteries for this purpose. For the block rate scenario, high injection is not penalized; the marginal revenue is just decreased. Thus, it limits the profitability of having a high PV capacity compared to its energy demand level, but it requires neither curtailment of the PV energy nor investing in storage technologies. The fraction of energy curtailed is zero for all scenarios except for the capacity and spot market tariffs. For the latter, the small fraction of curtailed energy is due to negative spot market prices as shown in the inset of Fig. 7. As a general trend, a larger battery size (relative to the building energy demand) increases the self-sufficiency ratio as shown in Fig. 6b. This trend is very pronounced for the spot market, solar and capacity tariffs, although a saturation appears for the latter for large battery autonomy.

In summary, compared to the reference scenario, dynamic volumetric tariffs (solar and spot market) promote investments in storage technologies since they provide economic opportunities to generate profit for the building owners. The capacity tariff promotes investment in storage which main action is to reduce consumption peaks. The block rate tariff promotes

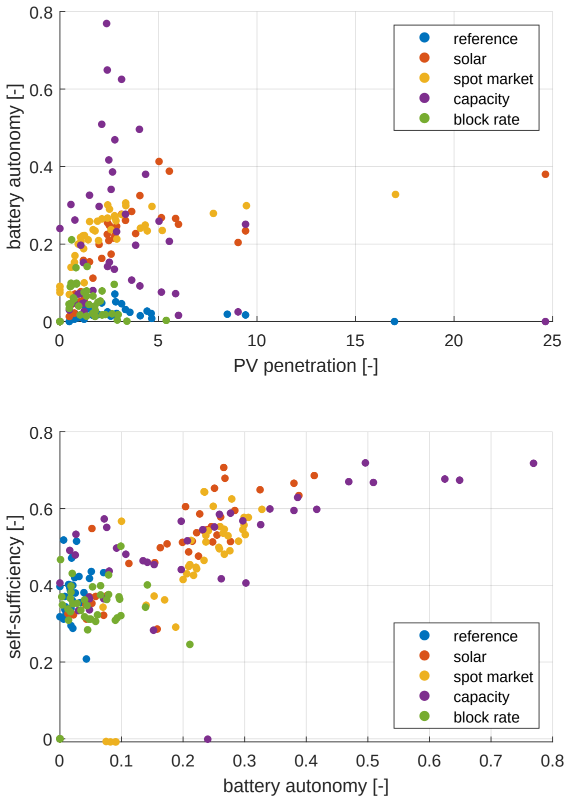


Fig. 6. Upper (a), battery autonomy versus PV penetration , lower (b) self-sufficiency level against the battery autonomy ratio.

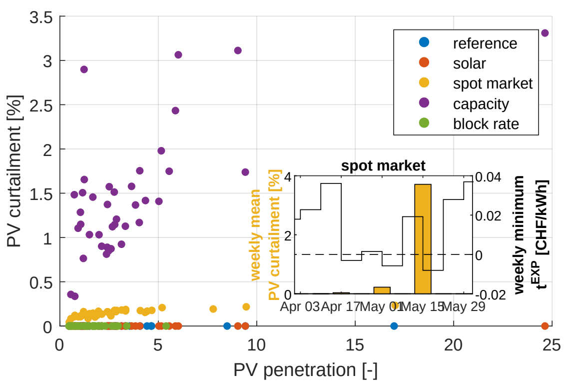


Fig. 7. Ratio of energy curtailed and PV penetration. In the inset, the bars are the weekly ratio of energy curtailed (left axis) and lines the weekly minimum t^{EXP} (right axis).

smaller PV penetration (thus, PV capacity) and battery capacity but achieves a self-sufficiency level similar to the reference case. As pictured in Fig. 5, these considerations have an impact on grid usage behavior. In particular, the grid usage ratios are higher (regardless when importing or exporting) for both the spot market and solar tariff. It is especially pronounced for the spot market case. Conversely, capacity tariffs significantly reduce the grid usage ratio for import, while the block rate tariff lowers both. Fig. 8 illustrates these observations. This figure allows us to distinguish between three types of grid user: the exporters (grid usage ratio for export above 1) and even reduce their import grid usage by covering their own consumption; the energy traders, who buy or sell energy to maximize their profit (import and export grid usage above 1); and the low grid users, who interact less with the network. Almost all buildings fall in this category for the block rate scenario. The following will show how these local design and operation adaptations affect the network operational metrics.

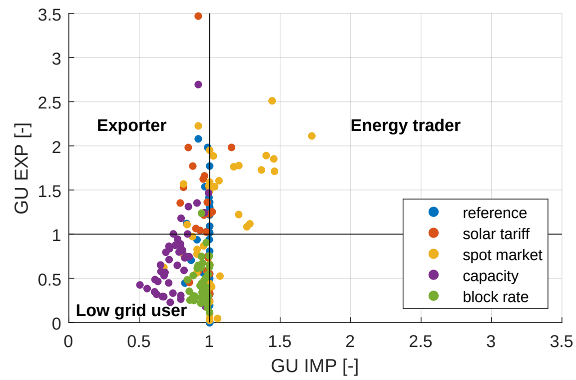


Fig. 8. Export power ratio vs import power ratio.

B. *Low-voltage grid impact*

In order to have a complete overview of the grid reaction to the different tariffs (with PV installations and batteries always present), two additional scenarios are added. The first one considers only the original load without any investment in PV or batteries; the second considers that all roofs are covered with PV (regardless of the profitability of such a decision) but with no investment in batteries. These two scenarios gives reference values for the grid impact metrics.

The load duration curve in Fig. 9 highlights the violation of the transformer power capacity for reverse power flow. All scenarios, except the load-only case, experience a maximum power flowing from the low-voltage side to the high-voltage side above 400 kW. The block rate tariff, with a significantly lower installed PV capacity, has the lowest maximum reverse power, but a significant number of hours are above 400 kW. The most-demanding scenario is the spot market scenario which exhibits the highest power demand and the highest injection power. The solar tariff also shows a significant increase in power demand compared to the other scenarios. This has direct consequences for the level of loading of the lines (ratio between current and the maximum nominal current of the line). Fig. 10 shows that line loading level is significantly higher for all scenarios including PV, with the most extreme values attained under the spot market and full PV scenarios. The block rate tariff helps to significantly reduce the loading level of the lines. In this case, even the most loaded lines are less congested than in the load-only scenario.

One of the main concerns of grid operators regarding high PV penetration is to keep voltage levels to a value as close as possible to 1 pu. As a matter of fact, all scenarios, except the

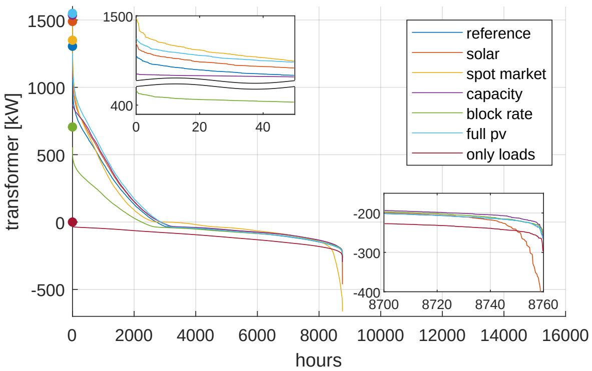


Fig. 9. Load duration curve at the transformer. Dots on the vertical axis indicate the total installed PV capacity per scenario. The nominal transformer capacity is 400 kW. Negative values indicate power flow from the high-voltage toward the low-voltage side.

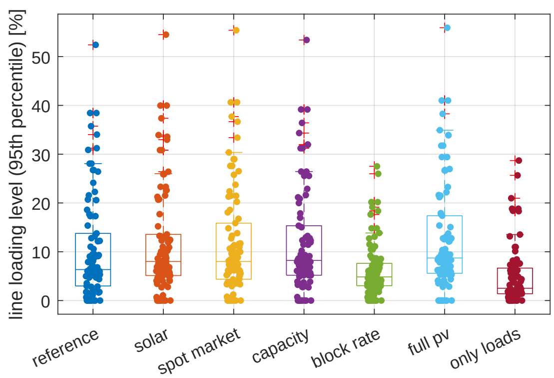
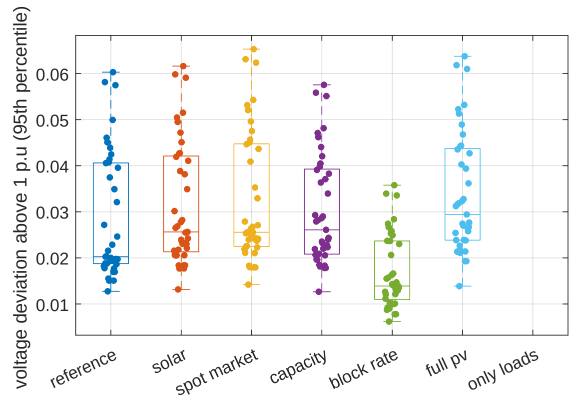


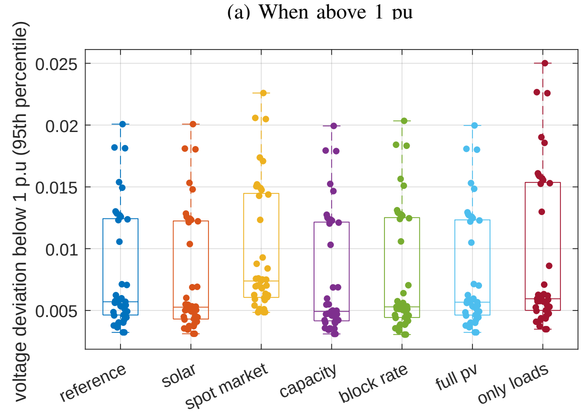
Fig. 10. 95$^{\text{th}}$ percentile of the line loading level.

spot market one, fulfill the criteria EN50160, meaning that the voltage levels fall within +-10% of the nominal voltage for 95% of each week. When considering only the case when the voltage deviations exceed 1 pu, Fig. 11a demonstrates the effectiveness of the capacity and block rate tariffs in terms of load management, as both lower the deviation of the most sensible bus compared to the reference and full PV case. Note that the load-only scenario is not displayed in this figure because the voltage levels never exceed 1 pu. Alternatively, when the load level is below 1 pu (Fig. 11b), only the spot market case significantly increases voltage deviations.

These observations highlight that advanced tariff structures can have two competing impacts. On the one hand, they may help mitigating the grid impact of distributed generation by promoting either small PV installations or moderate grid exchange. On the other hand, they can bring economic opportunities for significant investments in batteries and PV capacities but may increase the stress on the grid. The most-concerning aspect is the transformer capacity to bring the excess power from the low-voltage to medium-voltage side. Over/under-voltage and overloading of the lines are in all cases far less concerning. Although each scenario has been carefully calibrated to globally keep similar DSO revenues (with respect



(a) When above 1 pu



(b) When below 1 pu

Fig. 11. Voltage deviation distribution.

to the reference case), it is worth investigating *a posteriori* these revenues and the levelized cost of the energy demand (LCOE) in order to make sure that the calibrations do not lead to a net increase in the energy price.

C. Economic aspects

In the load-only scenario, the LCOE is 21 CHF cts/kWh (corresponding to the import tariff of the reference scenario), while the LCOE can become higher in the full PV scenario and explainins why, in the reference case, some roofs are not covered with PV. Additionally, in the solar and spot market scenarios, only a small fraction of the buildings exhibits an LCOE exceeding 21 cts/kWh, while the large majority would gain from switching to these tariff structures. For the capacity tariff scenario, a significant fraction of the buildings has an LCOE higher than the reference value, showing that, despite its positive impact on grid operation, such a tariff comes with a price for some building owners. The block rate scenario, though less prone for PV and battery investment, presents an LCOE lower than the reference values for all buildings. LCOE, however doesn't give any indication of the DSO revenues as shown in Fig. 13. Recalling that each tariff has been calibrated to keep the revenue for the DSO approximately equal to the one of the reference scenario, Fig. 13 highlights that after the optimization phase, the revenues change significantly due to the fact that each building optimize its operation in order to increase its own profit. The only presence of PV generators significantly lowers the DSO revenues as shown by comparing the only loads scenario with the full PV one. The block rate scenario actually slightly increases the revenue because the total installed PV capacity is smaller. The design of such a tariff is a matter of compromise between promoting distributed renewable energy and mitigating grid impact. There is a lack of literature for designing such block rate tariffs.

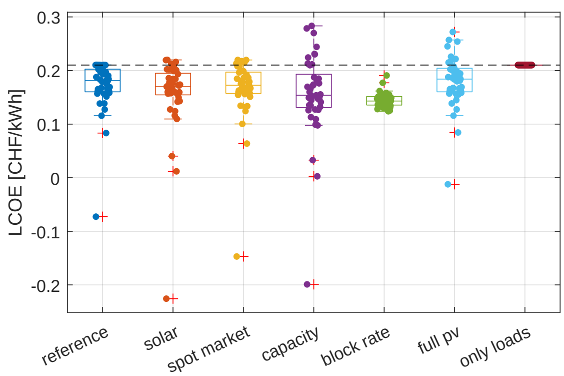


Fig. 12. Levelized cost of energy demand per scenario.

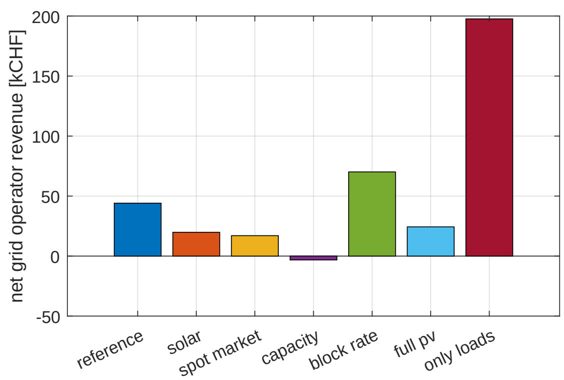


Fig. 13. Net revenue for the distribution system operator.

V. Conclusions

In this study, the optimization of 41 buildings under five different tariff scenarios, including three volumetric tariffs, one combination of volumetric and capacity tariff and one block rate tariff, was performed. The resulting systems vary in term of installed PV capacity and battery capacity. The highest PV penetration is achieved with the capacity tariff while this scenario significantly reduces the voltage deviation and the line loading level. Volumetric tariffs, with high price volatility such as in the spot market scenario, lead to more investment and profitability of the batteries but also increase stress on the network. Although the block rate scenario promotes smaller PV installation, it achieves the smallest median cost of providing energy for the end-users (from 18 cts/kWh in the reference case down to 14 cts/kWh). It reduces the 95$^{\text{th}}$ percentile of the positive voltage deviation of the bus with the largest deviation from 6% to 3.6% and reduces the maximum reverse power from 1060 kW to 550 kW, while remaining above the 400 kW nominal power of the transformer. Further studies should elaborate on the design of block rate tariffs to mitigate network impact and incentivize high penetration of PV. Indeed, the design and operation of PV-battery systems strongly depends on the tariffs parameters. The approach chosen to calibrate the tariffs has very significant impact on the resulting system. Hence, a deeper analysis on how to design and calibrate such tariffs is needed. The effect of a growing penetration of electric vehicles and heat pumps should also be considered.

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