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# Rate design with distributed energy resources and electric vehicles: A Californian case study

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ABSTRACT

The high penetration of distributed energy resources and electric vehicles is changing the way the electricity system is managed. In turn, the way utilities have been recovering their expenditures through tariffs needs reformulation. We investigate the impact of different retail tariff designs from a Californian scenario on private investment incentives and cost-shifting using solar PVs, stationary batteries, and electric vehicles. The private commercial facilities studied do not own the vehicles, and the vehicle owners are remunerated for energy services provided; this remuneration strongly depends on the connection hours of the vehicles and the type of tariff applied. EV net income varies annually from $57 to $218 per vehicle, reaching the highest values when stationary batteries are present and significant demand charges are applied. We found that an energy-based tariff incentivizes the adoption of solar PVs, bringing high private gains, but often with high cost-shifting. A shift toward coincident peak tariffs in the short term and capacity-based tariffs in the long run, if the cost of DERs continues to fall quickly, can alleviate cost-shifting caused by strong DER penetration. Finally, we derive policy implications from the results and earmark more sophisticated tariff designs for further investigation.

## 1. Introduction

The world's electricity demand is expected to grow by 60% between 2017 and 2040 to reach 35,500 TWh. However, the amount of $CO_2$ emitted must not be allowed to increase in pace with this demand but instead fall to half of today's level to follow the sustainability scenario of limiting temperature rise to 1.7–1.8 °C (IEA, 2018). The power sector is currently undergoing a bottom-up transformation caused by the continuous introduction of distributed energy resources at the consumer end. A system that was once almost purely centralized is nowadays becoming more decentralized as more distributed generation and storage are being installed (Perez-Arriaga et al., 2017). The increase in solar photovoltaics and stationary battery system adopters is mainly due to the decrease in overall costs and the development of a more substantial societal acceptance of the benefits of these renewable energy resources (Schumacher et al., 2019; Lee and Heo, 2016). Solar photovoltaics in both residential and commercial sectors have seen their costs fall by a factor of three since 2010 (Fu et al., 2018) and they are predicted to achieve around 1200 $/kW and 1000 $/kW for utility-scale PV by 2025 (NREL, 2020). At the same time, the average costs of lithium-ion battery packs also fell threefold from 2007 to 2014, down to 300 $/kWh (Nykvist and Nilsson, 2015), and are expected to reach 100 $/kWh by 2030, as a result of economies of scale from massive investments in research and development in the electric vehicle industry (IEA, 2018). More optimistic previsions foresee the achievement of this price level in 2024 (BloombergNEF, 2019) or even in 2023 (IHS-Markit, 2020). The need to decarbonize the mobility sector, which has a large share of the total worldwide $CO_2$ emissions, 24% in 2018, has been driving the penetration of electric vehicles (EVs) in recent years. The global number of EVs exceeded 7.1 million in 2019, up by 2.1 million since 2018 and 5 million since 2016 (IEA, 2020). However, EVs can be more than a mere transportation mode and can be considered a distributed energy resource (DER) if smart charging and vehicle-to-grid (V2G) capabilities are enabled.

*Abbreviations:* BESS, battery energy storage system; EV, electric vehicle; PV, photovoltaics; DER, distributed energy resource

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All these changes in the electricity scenario, with the uptake of innovative technologies, directly affect how utilities charge their customers a fair and cost-reflecting retail tariff. Consequently, the new and adjusted tariffs impact innovation uptake, evidencing a clear feedback loop. The tariff[1] structure is divided into energy charges,[2] network charges[3] (transmission and distribution) and taxes and levies.[4] Of these three tariff parts, the one including the distribution network has been the subject of growing debates among national regulatory authorities and academics over the last few years (Brown and Sappington, 2018; Pollitt, 2018; Brown and Faruqui, 2014). The discussions are primarily on how it should be redesigned according to the format (energy, capacity, fixed or a combination thereof), the temporal granularity (flat or time-of-use), and locational granularity (uniform or location-specific). The regulation authorities around the world design tariffs considering specific aspects, such as a combination of the state of the electrical grid, consumer behavior, policy objectives, and electricity mix. Schittekatte and Meeus (2020) argues that, in practice, fairness and cost-reflectiveness have a significant impact on the design of the network part. The results depend more on the state of the grid, if grid investments still have to be made or if costs are mostly sunk. To prevent a severe deficit in the utility's final budget caused by an increase in installed DERs, changing how electricity is produced and stored, a new rate design will be needed.[5]

This paper investigates the relations between EVs and DERs (PVs and batteries) in commercial buildings under different retail tariff schemes using a method similar to that proposed by Boampong and Brown (2020). The main goal is to observe (i) the facility private value impact, (ii) the grid operator financial impact quantified by cost-shifting values, and (iii) EV remuneration when adding an EV providing vehicle-to-grid services behind the meter alongside the DER mix. To the best of our knowledge, no study has assessed these aspects concomitantly, observing the impacts of rate designs on them. For instance, we complement the work of Boampong and Brown (2020) by assessing an extra optimistic DER cost scenario and including EVs as an electric storage option for commercial facilities. In addition, while in the prior work the major part of commercial load profiles has a valley around midday and a peak rising late afternoon, in our case, we adopted bell-shaped load curves typically present in commercial offices, warehouses, and medium-sized malls. We find that energy tariffs increase private economic gains and incentivize PV adoption, whereas capacity tariffs reduce cost-shifting under all combinations of DERs for the commercial buildings studied. This mainly happens when DER prices are low. However, the lowest cost-shifting with conservative DER prices is observed under coincident peak tariffs. Looking specifically at EV net income, we show that it varies annually from $57 to $218 per vehicle, reaching the highest values when batteries are present and demand charges are applied.

The Californian case is well suited to this study for several reasons. First, the state of California has one of the world's most aggressive targets concerning EVs, with 5 million vehicles on the road by 2030 (IEA, 2020). In addition, California government issued an Executive Order to phase out the selling of combustion engine vehicles by 2035. The Order states that all new cars and passenger trucks sold in California must be zero-emission vehicles by 2035 (GOV, 2020). Renewable energy should provide 50% of the state's energy production by 2030 with a considerable amount of solar PV encouraged via rebate programs of the order of 6 billion dollars until 2016 (CEC, 2019). Although there are no more state rebates for solar installations, the focus now is to push storage with the Self-Generation Incentive Program, which can give an incentive as high as 400 $/kWh for battery systems (CPUC, 2019). Secondly, the electricity tariffs applied are highly diversified among the utilities in the state. It is possible to find buildings under time-of-use energy or capacity-based rates with different attributed on-peak periods and high-value variability within the state (SCE, 2019a). The various rate designs, the relatively low cost of DERs, and the high penetration of EVs enable us to study different scenarios combining them.

The structure of our paper is as follows. First, an overview of the problem is given to explain the motivation of the research, with a literature review support. The data used are then presented, along with the method proposed. In Section 4, the results are presented according to two types of investments. In Section 5, we discuss the results and derive policy implications. Finally, the last section comprises the conclusion.

## 2. Literature review

In this section, we analyze three main strands of the literature. The first concerns the interaction between EVs, solar PVs, and distributed battery storage, which has received much attention recently due to its potential help in decarbonizing both power and mobility sectors at the same time. The second looks at the impacts of diversified tariff schemes when grid users install DERs. Finally, the third domain is the EV remuneration when energy services are provided to the grid.

The way that the synergy between PVs, EVs, and distributed stationary batteries can help to decarbonize the power and mobility sector is to effectively integrate solar energy while lending the grid more flexibility using battery storage. Solar PVs produce carbon-free low marginal cost electricity that can be used to enhance private self-consumption and power electric mobility with green energy for batteries and EVs, respectively. Charging EVs with PVs on a small microgrid scale can significantly decrease demand peaks and defer network reinforcement investments (Kam and Sark, 2015). Kuang et al. (2017) show that this synergy can be more relevant for certain categories of buildings, e.g. offices, restaurants, and warehouses, where a smart control strategy of EV/PV energy building systems can reduce costs by up to 18%. Moreover, low-cost batteries can support EV charging by synchronizing the intermittent PV generation with EV demand (Kaschub et al., 2016). We contribute to this field by analyzing the private investment impact of different DER combinations under modern tariff schemes. Although the benefits of the coupling between these DERs are clear, they are deeply impacted by the economic environment and inappropriate regulations. Obsolete tariffs and obsolete ancillary service market designs could jeopardize all the potential benefits brought by the coupling (Freitas Gomes et al., 2020).

The high penetration of DERs in the electricity system will not only demand changes in the way utilities technically manage their grid but also require reformulation of the tariffs applied to end-customers (Burger et al., 2019). Classic formulations using energy-based tariffs with net-metering are not efficient in recovering network costs, leading to cross-subsidy issues, mainly when high shares of solar PVs are installed (Simshauser, 2016; Sioshansi, 2016; Schittekatte et al., 2018). In this case, the electricity savings of prosumers that invest in DERs would be higher than the avoided costs of the utility, threatening the financial equilibrium of the utility. As a consequence, utilities would need to raise their tariffs to recover their costs, and non-prosumer customers could see their bills increase due to the increase in the tariff for all network users. This would initiate the death spiral of utilities (Costello and Hemphill, 2014) in which low-income customers are usually the most severely affected by this tariff rise. According to Burger et al. (2020), network cost recovery can be enabled using differentiated fixed charges while preserving marginal costs signals.

[1] For simplicity, the term tariff and rate will refer to the retail tariff when used alone in the text.

[2] The energy part reflects the wholesale electricity market where retailers buy electricity at a set price to honor contracts with their customers.

[3] The network part reflects the costs of transmitting and distributing the electricity from the generation sites to end-customers. It should include the costs inflicted on the network by the user's load profiles.

[4] Finally, the taxes and levies applied are decided by the national governments.

[5] This problem inflicted on the network by the presence of DERs is called the "death spiral of utilities" (Costello and Hemphill, 2014).

They demonstrate that fixed charges designed using customer demand profiles or geography can provide efficient bill protection. Several studies propose a solution to these issues based on demand charges (or capacity tariffs). For instance, Simshauser (2016) argues that a capacity-based demand tariff is a more efficient structure that improves stability, cost-effectiveness, and fairness in allocating network sunk costs between prosumers and ordinary consumers. Sioshansi (2016) proposes a two-part tariff based on a time-invariant energy charge as its first part, the second part being a capacity charge based on the cost of the peaking capacity, which will have cost-allocation benefits in the face of DERs. In the same line of thought, Dameto et al. (2020) propose a two-part tariff with a peak-coincident and a fixed charge in a current context. They argue that this rate configuration promotes efficient network usage as well as an equitable share of the costs for all the network users.

There is no consensus in the literature on capacity-based demand tariffs as the means to balance efficiency and equity. Borenstein (2016) states that fixed charges reflecting customer service levels and time-varying pricing are more effective than demand charges in kW.[6] Another problem with this type of rate is that it can (over)incentivize storage adoption and create similar efficiency and fairness issues in network cost allocations to those of pure energy charges if low-cost batteries are available (Schittekatte et al., 2018). Besides considering solar PVs and stationary batteries like previous studies, other studies also included EVs in their tariff design analysis (Küfeoğlu and Pollitt, 2019; Hoarau and Perez, 2019). Küfeoğlu and Pollitt (2019) show the counterbalancing effect of EVs over the tariff increase caused by PVs under the current energy-based rate in Great Britain. If batteries are added to the DER mix, Hoarau and Perez (2019) show that EVs and DERs may conflict under the main tariffs based on energy-based and capacity-based schemes by inducing negative spillovers on each other through the recovery of grid costs. A change of regulation would make winners and losers, so regulators should be careful about which kind of technology they want to promote.[7] Our paper goes a step further to study the impact on avoided costs from a utility perspective and the cost-shifting to find what DER mix and tariff would be fairest assuming that when there is cost-shifting these costs may be passed on to consumers who do not install a DER system.[8]

EVs can provide a good number of front-of-the-meter services to both transmission and distribution grids, increasing the opportunity of economic gains for the user. As pointed out in Eid et al. (2016) concerning the short-term market, EVs can provide frequency containment reserves and secondary reserves according to the market rules at the transmission level which involve more actors in the electricity system.[9] Additionally, they can participate in congestion management, voltage regulation, and network investment deferral at the distribution grid level (Pearre, 2019). Behind-the-meter services could also be profitable depending on the market and tariffs applied, varying from pure energy arbitrage or demand charge reduction. However, not all of them have the same economic value. For instance, Thompson and Perez (2020) list the annual value stream ranges of these services; they found that bill management, which is mainly time-of-use management and demand charge reduction, could bring the highest remuneration. Since that research was done using different markets from various utilities, the conditions in which those revenues arise are heterogeneous, including the tariffs used by each utility. Therefore, it is essential to know under what types of electricity tariff it is possible to have discussed revenues, especially behind-the-meter services. Finally, we contribute to the literature on EV energy services by assessing the maximum remuneration vehicle-to-grid enabled EVs can obtain connected to commercial buildings by providing services to the facility according to the DER mix and tariff schemes applied.

## 3. Model and data

This section describes the model used to pursue the main goals of this research and presents the data used as parameters to feed the model.

### 3.1. Methodology

The method used to obtain the results is based on that used in Boampong and Brown (2020), relying on two complementary tools, as shown in Fig. 1. First, we use the Distributed Energy Resources Customer Adoption Model (DER-CAM) developed by Lawrence Berkeley National Laboratory to simulate private investments using DERs, in our case PVs, stationary batteries, and EVs. We couple it with the Avoided Cost Model (ACM) developed by E3 (2018), which accounts for the costs avoided by the electricity supply-side when one kWh is returned to the grid or is no longer consumed by the private facility.

Two different types of investments are considered in this study: exogenous and endogenous. For the exogenous part, we consider three possible DER combination (PVs plus battery, PVs plus electric vehicles, and PVs plus battery and electric vehicles) in which the amount of DERs installed is fixed so that it is possible to isolate the impact of changes in tariffs, leaving the model only the task of finding the optimal charge and discharge strategies. As we go toward the endogenous investment, the model chooses the optimal charge and discharge strategies concomitantly with the amount of DERs to minimize private costs. The latter option is more likely once investors act rationally to find the highest possible net present value. Nevertheless, the study of the exogenous case can shed light on many hidden relationships between DERs according to the retail scheme applied.

We then compute the NPV, taking into account the electricity savings minus the capital and operation expenditures of all the investments to check whether they are profitable. The main input is the annualized cash flow, which is given by the difference between the base case scenario annualized energy costs without DER and the scenario annualized energy costs with a DER. We considered a nominal discount rate of 8%, a maximum payback period of 20 years (the lifetime of solar PVs), and an inflation rate of 1.5%.[10] The costs of DERs and the base case electricity value (the cost of electricity when there are no DERs installed for a specific facility) will be decisive as to whether the value is positive.

[6] These tariffs are especially wasteful, from a societal point of view when the customer's peak demand does not coincide with the system's peak. The coincident peak demand tariff could send the right signal but may create another coincident peak period in another period.

[7] This question is still open to discussion among researchers, network operators and regulators seeking to determine the tariff structure that is the most effective from the system point of view, and fairest, from the consumers' perspective, under different DERs such as batteries, EVs, PVs or heat pumps.

[8] In line with Boampong and Brown (2020), our proxy for fairness is the average cost-shifting caused by the private facilities. Contrary to Simshauser (2016) and Schittekatte et al. (2018) the cost-allocation analysis among prosumers and ordinary consumers is not in the scope of this study.

[9] Besides the Transmission System Operator and Distribution System Operator or the Independent System Operator and Utilities in our Californian scenario, we also have the aggregator, a commercial entity responsible for grouping distributed energy resources such as EVs, to provide grid services as an intermediator between the system operator and EV owners.

[10] For a yearly time period i, the net present value is calculated by: $\sum_{i=1}^{20} \frac{Annualized\ cash\ flow \cdot (1+inflation)^i}{(1+nominal\ discount\ rate)^i}$.

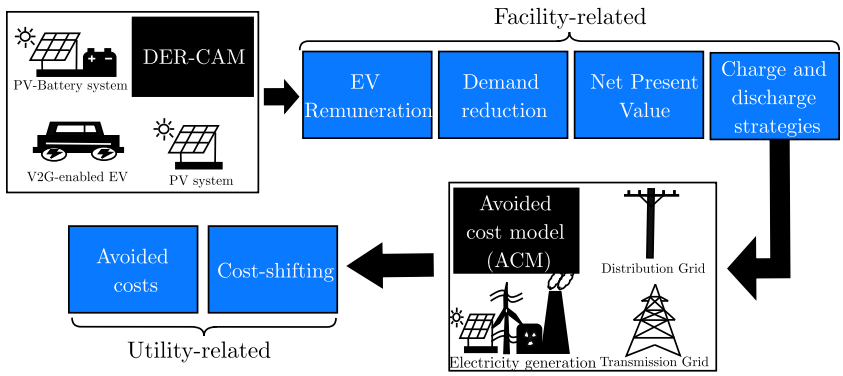



**Fig. 1.** Methodological framework.

### 3.1.1. DER-CAM optimization program

DER-CAM models the optimization problem to minimize the annual costs of facilities investing in DERs according to the tariff structure applied as a Mixed-Integer Linear Program (MILP). The adapted total cost function of the fully endogenous model is divided into electricity costs, DER costs, EV costs, and export revenues:

$$Min\ c_{total} = c_{elec} + c_{DER} + c_{EV} - \sum ExportsRev \tag{1}$$

We implement compound retail rates such as time-varying three-part tariffs taking into account diversified fixed, energy (in kWh), and demand charges (on-peak, mid-peak, coincidental or non-coincidental) so that the variable electric costs reflect the tariff components summed over the year. The DER costs include capital and operating expenditures over a specified duration for energy resource installed by the private facility. We can compute the Net Present Value (NPV), considering the electricity savings minus the capital and operation expenditures of all the investments to check whether they are profitable.

The EV costs then account for the additional expenditures linked to EV ownership; for instance, unlike PVs and a stationary battery, only the charging station is owned by the private facility. By contrast, the EV itself is not, meaning that costs such as battery degradation caused by private facility strategies and the electricity used coming from home charging should be refunded.[11] Since the vehicle starts home charging in the evening, the charging event is under the off-peak period, making the discharge to the grid of the facility virtually profitable.[12] Although discharging EV battery into the facility grid can bring high financial gains, in the case of PV generation excess, charging these vehicles can also become profitable. The model allows the EV owner to pay the facility back if the net energy exchanged between the vehicle and the facility's grid becomes negative (see the first part of Eq. (A.4)), that is, if the charging events using electricity generated in the facility outweigh the discharging events into the facility's grid. There are, therefore, financial flows between these two players: the private facility and EV owner. These financial flows will depend on the electricity costs during home charging, battery degradation caused by the grid usage of the facility, and electricity bill reduction due to energy services provided by the EV.[13] If the sum of the first two factors is positive, in this case, the first flow will be from the facility toward EV owners; if it is negative, the flow will go in the opposite direction (see Eq. (A.4)). This first flow is mainly a financial compensation: in the former case, compensation for the electricity used to charge EVs at their owners' homes under a specific EV tariff and the battery degradation caused by V2G services provided to the facility grid. Then, there is a second flow corresponding to the value created using EVs. This flow captures the spread between home charging (or local solar PV charging) and the discharging to arbitrage energy and offset demand at the local facility. We focus on the most valuable service provided in California by EVs, which is bill management (maximum demand reduction stacked with energy arbitrage), according to Thompson and Perez (2020) to verify the effects of electricity tariffs on this type of service. As this kind of service does not directly involve any third parties such as aggregators, distribution system operators, or transmission system operators, the sharing of value is defined between facility and EV owners, and our goal is to assess the maximum amount of revenue to be split between them. There are several ways to define vehicle owners' net income based on the total amount to be split. In our case, we assume that both parties have the same bargaining power so that a fifty-fifty strategy will be adopted and the total value created by EVs will be equally shared between EV owners and the commercial facility.[14] Finally, the additional export revenue can represent the financial contribution of any incentive program, like solar or storage feed-in-tariff or even net-metering schemes, to the final total cost.

The constraints applied to the program require it to meet several conditions so that the facility DERs can work properly together. First, the energy balance equation matching supply and local demand links all the generation coming from the PVs, grid purchases, and storage discharge with the charging episodes and the load of the facility. The solar PV maximum output is then limited by its maximum peak efficiency, solar radiation conversion efficiency, and solar insolation. Finally, storage maximum and minimum state of charge, together with the charging input and discharge output power, are considered separately to prevent them from occurring simultaneously. General constraints are also present to define boundaries for the DER operations, defining an arbitrarily large number **M** to avoid unexpected outcomes such as buying and selling (exporting) electricity at the same time, as stated in Eqs. (A.11) and (A.12). Also, the annuity factors and the payback constraint in which all investments must be repaid in a period shorter than the payback period are defined.

### 3.1.2. Avoided Cost Model (ACM)

The Avoided Cost Model (ACM), developed by E3 (2018), is used in demand-side cost-effectiveness proceedings at the California Public Utilities Commission (CPUC) to evaluate California's DER program components. We use this model to proxy for the avoided cost associated with a DER unit output, enabling us to calculate the cost-shifting

[11] The full equations and constraint formulations are presented in Appendix A based on Cardoso et al. (2017), Stadler et al. (2013), Momber et al. (2010).

[12] A study from Idaho National Laboratory show that around 85% of EV charging in the United States is done at home (INL, 2016).

[13] The value is the actual net income and is calculated by the difference between the total energy costs in the scenario without EVs and the one with the EV providing energy services to the facility.

[14] Chapter 4 of Borne (2019) describes more complex negotiations in the V2G ecosystem where actors have different bargaining power.

| Month \ Hour | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 64.63 | 63.66 | 62.72 | 62.68 | 63.69 | 76.75 | 93.93 | 123.55 | 90.49 | 81.98 | 76.91 | 73.87 | 70.64 | 70.75 | 73.80 | 77.15 | 93.99 | 117.19 | 117.93 | 103.62 | 99.22 | 81.55 | 74.03 | 69.11 |
| 2 | 63.36 | 60.83 | 58.82 | 58.83 | 61.73 | 72.92 | 124.04 | 118.71 | 92.90 | 70.67 | 67.23 | 65.28 | 0.00 | 0.00 | 64.95 | 68.92 | 81.96 | 105.57 | 130.33 | 116.38 | 108.63 | 90.75 | 73.93 | 65.74 |
| 3 | 57.98 | 57.66 | 56.12 | 57.30 | 72.04 | 106.52 | 117.37 | 104.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 75.14 | 115.88 | 149.19 | 118.10 | 100.97 | 81.00 | 70.90 | 63.76 |
| 4 | 59.14 | 56.42 | 59.12 | 64.85 | 78.06 | 103.99 | 101.22 | 29.64 | 0.00 | 0.00 | 54.21 | 50.51 | 53.92 | 60.21 | 62.08 | 0.00 | 0.00 | 85.86 | 130.20 | 120.47 | 90.21 | 76.72 | 62.87 | 59.26 |
| 5 | 57.12 | 56.45 | 56.40 | 57.20 | 71.62 | 95.50 | 36.97 | 0.00 | 0.00 | 29.25 | 82.13 | 90.38 | 85.40 | 98.74 | 125.07 | 72.60 | 100.33 | 132.57 | 211.16 | 162.04 | 101.44 | 83.13 | 68.64 | 62.45 |
| 6 | 61.45 | 60.43 | 61.97 | 61.79 | 66.78 | 76.48 | 67.84 | 27.94 | 29.63 | 31.90 | 40.22 | 48.13 | 58.84 | 92.83 | 141.76 | 322.79 | 372.68 | 528.62 | 783.64 | 319.04 | 124.78 | 97.30 | 83.52 | 66.28 |
| 7 | 63.35 | 62.89 | 61.32 | 60.41 | 67.81 | 72.09 | 72.12 | 70.54 | 28.27 | 29.05 | 34.98 | 39.31 | 44.91 | 51.83 | 121.82 | 133.05 | 151.83 | 184.68 | 208.24 | 121.29 | 97.03 | 76.43 | 70.64 | 70.36 |
| 8 | 63.96 | 61.63 | 60.22 | 61.30 | 65.40 | 84.74 | 83.06 | 76.99 | 85.49 | 105.40 | 93.43 | 104.83 | 127.34 | 182.30 | 296.63 | 320.68 | 452.29 | 564.82 | 513.94 | 256.75 | 129.01 | 97.31 | 81.99 | 71.94 |
| 9 | 73.61 | 69.15 | 66.77 | 64.08 | 64.28 | 86.41 | 85.48 | 71.41 | 77.87 | 91.27 | 95.87 | 108.21 | 125.76 | 156.62 | 233.77 | 357.69 | 516.34 | 914.08 | 599.01 | 264.15 | 120.52 | 97.94 | 85.69 | 80.13 |
| 10 | 73.75 | 70.01 | 68.41 | 70.46 | 85.13 | 118.81 | 129.42 | 94.97 | 74.53 | 28.01 | 31.03 | 40.86 | 107.11 | 123.33 | 147.07 | 219.63 | 464.89 | 660.09 | 444.38 | 213.37 | 181.61 | 131.87 | 103.82 | 86.98 |
| 11 | 91.32 | 84.20 | 78.20 | 74.27 | 77.96 | 103.07 | 130.64 | 107.84 | 86.09 | 74.80 | 73.41 | 73.65 | 73.77 | 74.38 | 77.91 | 102.64 | 136.29 | 238.74 | 208.17 | 135.53 | 132.75 | 113.30 | 90.61 | 87.86 |
| 12 | 81.14 | 77.17 | 73.43 | 75.07 | 79.31 | 95.26 | 123.95 | 115.34 | 86.98 | 76.18 | 68.94 | 66.61 | 66.41 | 66.97 | 69.48 | 81.62 | 120.55 | 147.87 | 134.66 | 124.31 | 122.80 | 105.82 | 105.05 | 91.92 |

(a) Energy-related Peak Marginal Avoided Costs ($/MWh)

| Month \ Hour | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 5 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 6 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.03 | 0.84 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.61 | 3.54 | 2,024.86 | 7,925.93 | 9,050.50 | 8,813.61 | 239.63 | 101.94 | 0.36 | 0.00 | 0.00 | 0.00 |
| 8 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 4.04 | 181.41 | 652.27 | 8,686.98 | 7,116.88 | 2,250.61 | 485.97 | 1.78 | 0.00 | 0.00 | 0.00 |
| 9 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.66 | 5,209.01 | 12,934.90 | 16,994.56 | 22,171.92 | 22,822.83 | 5,784.20 | 1,706.36 | 4.52 | 0.00 | 0.00 | 0.00 |
| 10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 8.47 | 4.86 | 2.74 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

(b) Capacity-related Peak Marginal Avoided Costs ($/MWh)

| Month \ Hour | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 64.63 | 63.66 | 62.72 | 62.68 | 63.69 | 76.75 | 93.93 | 123.55 | 90.49 | 81.98 | 76.91 | 73.87 | 70.64 | 70.75 | 73.80 | 77.15 | 93.99 | 117.19 | 117.93 | 103.62 | 99.22 | 81.55 | 74.03 | 69.11 |
| 2 | 63.36 | 60.83 | 58.82 | 58.83 | 61.73 | 72.92 | 124.04 | 118.71 | 92.90 | 70.67 | 67.23 | 65.28 | 0.00 | 0.00 | 64.95 | 68.92 | 81.96 | 105.57 | 130.33 | 116.38 | 108.63 | 90.75 | 73.93 | 65.74 |
| 3 | 57.98 | 57.66 | 56.12 | 57.30 | 72.04 | 106.52 | 117.37 | 104.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 75.14 | 115.88 | 149.19 | 118.10 | 100.97 | 81.00 | 70.90 | 63.76 |
| 4 | 59.14 | 56.42 | 59.12 | 64.85 | 78.06 | 103.99 | 101.22 | 29.64 | 0.00 | 0.00 | 54.21 | 50.51 | 53.92 | 60.21 | 62.08 | 0.00 | 0.00 | 85.86 | 130.20 | 120.47 | 90.21 | 76.72 | 62.87 | 59.26 |
| 5 | 57.12 | 56.45 | 56.40 | 57.20 | 71.62 | 95.50 | 36.97 | 0.00 | 0.00 | 29.25 | 82.13 | 90.38 | 85.40 | 98.74 | 125.07 | 72.60 | 100.33 | 132.57 | 211.16 | 162.04 | 101.44 | 83.13 | 68.64 | 62.45 |
| 6 | 61.45 | 60.43 | 61.97 | 61.79 | 66.78 | 76.48 | 67.84 | 27.94 | 29.63 | 31.90 | 40.22 | 48.13 | 58.84 | 92.83 | 141.76 | 322.80 | 372.69 | 528.65 | 784.48 | 319.11 | 124.78 | 97.30 | 83.52 | 66.28 |
| 7 | 63.35 | 62.89 | 61.32 | 60.41 | 67.81 | 72.09 | 72.12 | 70.54 | 28.27 | 29.05 | 34.98 | 39.38 | 45.52 | 55.37 | 2,146.68 | 8,058.97 | 9,202.33 | 8,998.29 | 447.87 | 223.23 | 97.39 | 76.43 | 70.64 | 70.36 |
| 8 | 63.96 | 61.63 | 60.22 | 61.30 | 65.40 | 84.74 | 83.06 | 76.99 | 85.49 | 105.40 | 93.43 | 104.83 | 127.39 | 186.33 | 478.04 | 972.95 | 9,139.27 | 7,681.69 | 2,764.54 | 742.72 | 130.79 | 97.31 | 81.99 | 71.94 |
| 9 | 73.61 | 69.15 | 66.77 | 64.08 | 64.28 | 86.41 | 85.48 | 71.41 | 77.87 | 91.27 | 95.87 | 108.25 | 127.42 | 5,365.64 | 13,168.68 | 16,922.25 | 22,688.26 | 23,736.91 | 6,383.21 | 1,969.51 | 125.04 | 97.94 | 85.69 | 80.13 |
| 10 | 73.75 | 70.01 | 68.41 | 70.46 | 85.13 | 118.81 | 129.42 | 94.97 | 74.53 | 28.01 | 31.03 | 40.86 | 107.11 | 123.33 | 147.07 | 219.63 | 473.36 | 664.95 | 447.12 | 213.38 | 181.61 | 131.87 | 103.82 | 86.98 |
| 11 | 91.32 | 84.20 | 78.20 | 74.27 | 77.96 | 103.07 | 130.64 | 107.84 | 86.09 | 74.80 | 73.41 | 73.65 | 73.77 | 74.38 | 77.91 | 102.64 | 136.29 | 238.74 | 208.17 | 135.53 | 132.75 | 113.30 | 90.61 | 87.86 |
| 12 | 81.14 | 77.17 | 73.43 | 75.07 | 79.31 | 95.26 | 123.95 | 115.34 | 86.98 | 76.18 | 68.94 | 66.61 | 66.41 | 66.97 | 69.48 | 81.62 | 120.55 | 147.87 | 134.66 | 124.31 | 122.80 | 105.82 | 105.05 | 91.92 |

(c) Total Peak Marginal Avoided Costs ($/MWh)

**Fig. 2.** Marginal peak avoided costs profile for Forecasting Climate Zone 9 in 2020.

measurements when coupled with private economic savings from DER-CAM. The ACM calculates the cost avoided by the utility by not producing and delivering one extra unit of energy. This calculation is made by dividing the map into 16 Climate Zones in California,[15] and the cost itself into nine components: Energy, Losses, Ancillary Services, Cap and Trade, GHG Adder, Societal Criteria Pollutant, Capacity, Transmission, and Distribution costs.

Energy and Losses give the hourly marginal cost of providing a unit of energy from the wholesale market to end-users (adjusted for line losses). Ancillary services give the marginal cost of providing reliable services to the grid to keep it stable.[16] Cap and Trade costs give the marginal cost of $CO_2$ emissions associated with the marginal generation technology based on projections of California's cap-and-trade policy. The GHG Adder and Societal Criteria Pollutant costs give the avoided costs associated with reducing the need to procure additional renewable output to meet Renewable Portfolio Standards requirements. We group these six components in our analysis under Energy-based costs. The last three components are referred to as capacity-related cost components. Generation capacity gives the avoided costs from not procuring additional production capacity to meet peak demand. Transmission and distribution capacity gives the costs of expanding capacity to meet system peak demand. We set the ACM on the Climate Zone 9, Los Angeles suburb areas, and SCE utility territory, as this setting accurately proxies the avoided costs for our sample. The model computes 2020, 2025, 2030, and 2035 levelized avoided cost so that each year can be the reference for the next four, accounting for twenty years in total.[17] To achieve numerical traceability, DER-CAM uses three representative day-types per month: weekday, weekend day, and peak day. The calculation of the weekday and weekend day is done using average values across the month. For the peak day, the maximum observed load during one day is filtered and used as the peak day profile.[18] The yearlong hourly data computed by the ACM is therefore transformed into these three representative profiles to match dimensionally the results from DER-CAM.

We regress the real hourly weekday and weekend avoided cost profiles (as a dependent variable) on the representative average avoided profile day of each month to find how well the average profiles capture the real avoided cost variation. We calculated the average R-squared value for all four years (energy plus capacity avoided costs). The satisfactory values of 0.8305 for weekdays and 0.8906 for weekends are obtained.

Fig. 2 shows the breakdown of peak avoided costs for Climate Zone 9 per 12 months and 24 h in 2020 divided into energy- and capacity-related avoided costs. Along the year, there are marked variations for both energy-related and capacity-related costs caused by the different season characteristics. In general, during spring months, low marginal avoided costs are observed while the hydro production is high, and during summer, on the other hand, high marginal avoided costs are present because the system strongly depends on natural gas power plant generation to match the demand and cope with the duck curve challenge driven by high solar PV production.[19]

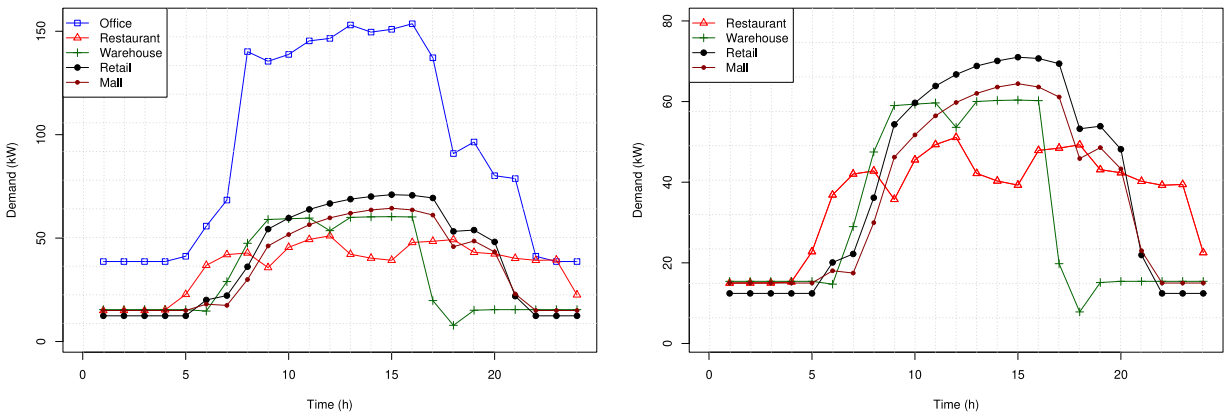
[15] These zones are called forecasting climate zones (FCZ), where each one has its commercial electricity supplier. These utilities can serve more than one zone. The largest ones are Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and Los Angeles Department of Water and Power (LADWP).

[16] EVs providing behind-the-meter services are easily coupled with the Avoided Cost Model since the utility sees them as a (mobile) battery. For in-front-of-the-meter services, some modifications should be made in the method to avoid counting the same service twice, since the model already accounts for the ancillary service procurement cost component.

[17] 20 years will be the period taken to calculate the net present value of the investment, which coincides with Solar PV lifetime.

[18] A useful data-processing tool was developed by Lawrence Berkeley National Laboratory to convert the load data into representative peak, weekday, weekend profiles for each month (LBNL, 2019).

[19] During the summer months (July, August, and September) when the system highly depends on costly natural gas plants, the generation capacity




(a) Building Load Profiles (b) Smaller Building Load Profiles

**Fig. 3.** Commercial building load profiles.

From an intraday perspective, there are significant variations during the middle of the day and evening hours, especially for the spring and summer months. The avoided costs are driven mostly by energy-related costs, but from July to September, from 2 PM until 9 PM, the capacity-related costs by far outweigh the energy-related costs, thus driving the total avoided cost. All this high variability in the total avoided costs show that the value of storage (stationary batteries and electric vehicles) is strongly dependent on the period, season, and charge and discharge strategies.

We couple the ACM with results from DER-CAM to calculate the avoided costs for each facility under specific tariffs. We also study two different cases to calculate the average avoided costs of the facilities. In case 1, the facility peak day never overlaps with the system peak avoided costs; instead, it overlaps with the typical avoided costs for a weekday during a specific month. This case is the most likely to occur in day-by-day operations. In case 2, the private facility peak overlaps precisely with the system peak avoided costs profile, meaning when the system is more constrained. These two cases show practically the same qualitative results, differing only in the amount of final aggregated and average avoided costs. They provide bounds for each tariff and technology mix, showing the limits that it is possible to have within cases with more than one facility peak day; in our case, we assumed three peak days per month. Not only will the demand reduction during the system constrained hours to be the decisive factor in terms of total avoided costs, but the discharging and charging strategies during the different hours will also have an influence. The last metric, cost-shifting, measures the difference between the private savings and the avoided costs of the system, i.e. the amount of money not recovered by the utility due to the presence of DERs.[20] This can be used as an equity proxy for tariffs since positive cost-shifting may imply a rise in tariffs for all consumers. The higher the cost-shifting, the higher the propensity to raise tariffs to recover all the utility costs, mainly those related to the electric network usage, contributing to the death spiral of utilities (Simshauser, 2016). Ideally, zero cost-shifting means that the annual savings of the private facilities are precisely the avoided costs for the utility. This means that the tariff is perfectly adapted to avoid inequalities between those who have DERs and those who do not. However, it is hard to achieve this goal given the distortions in electricity bills caused by the DERs under ill-adapted tariffs.

### 3.2. Data

The next section presents and justifies the choice of input data and parameters to run the model.

#### 3.2.1. Load profiles

To find the private value impact of the installed DERs, we need to define what kind of sites to consider and the techno-economic characteristics of the resources. The load profile of commercial sites will be used for several reasons: DERs can play an essential role in electricity consumption reduction in the building sector, as around half of the global electricity demand today is in this sector[21]; Secondly, the load profile peak is synchronized with the PV production during the day, leading to higher economic gains without the need for financial incentives for renewables such as feed-in-tariffs or net-metering schemes.

The five load profiles used shown in Fig. 3 are the average peak day profile for September from commercial reference sites developed by the U.S. Department of Energy (DoE, 2013),[22] which include a medium office, restaurant, warehouse, retail, and a medium mall. We transform the yearly data into DER-CAM weekday, weekend, and peak load profiles as done with the avoided cost data. We also regress the real hourly weekday and weekend profiles (as a dependent variable) on the representative average profile day of each month to find how well the average profiles capture the real demand variation. The calculated average R-squared value for all five building loads is then 0.8647 for weekdays and 0.7303 for weekends.

#### 3.2.2. Electricity retail rates

The diversity offered by SCE's retail rates couple perfectly with the assortment of DERs applied in this study. Energy- and capacity-based tariffs, with high demand charges, make a reliable scenario to analyze the sensitivity of many parameters due to tariffs. Fig. 4 shows three different commercial and industrial (C&I) tariffs based on the rates proposed by Southern California Edison's C&I tariff book for general services (GS2) with a maximum demand ranging from 20 kW to 200 kW (SCE, 2019a). All of them are three-part tariffs, which include fixed, energy, and capacity charges. The difference lies in the weighting of each part. The temporal granularity is a time-of-use (TOU) approach with on-peak, mid-peak, off-peak and even super-off-peak

costs are the major part of capacity costs. Network capacity costs surpass generation capacity costs in the following month due to the absence of these peak power plants.

[20] A positive value of cost-shifting means that the utility has a deficit in their budget caused by the DERs; on the other hand, a negative one represents a surplus, which can lead to a decrease in tariff value.

[21] It has also accounted for 52% of global electricity demand growth since 2000, contributing nearly 55% (7,200 TWh) to global growth through 2040 (IEA, 2018).

[22] These datasets are hourly profile data over a year for several commercial sites representing approximately 70% of the commercial buildings in the U.S.

periods during winter. Lastly, the rates are uniformly adopted under SCE's territorial service zones.[23] We will use three tariff structures in total: an energy-based tariff (TOU-ENE), a capacity-based tariff (TOU-CAP), and a coincident peak demand tariff (TOU-COIN) in which all demand charges are shifted toward a specific hour. In our case, the coincident hour varies between 5 and 7 PM over the year due to the highest grid constraints observed in a given month.[24] The coincident hour for a month is set a month before by the utility, so commercial buildings can formulate beforehand their strategies to reduce demand charges.[25] Finally, no complementary assistance programs (e.g., feed-in-tariffs and net-metering) were applied alongside the rates to check whether DER investments would still be profitable under these conditions. It is important to measure how mature DER investments are without utility financial support since great uncertainties are present around these assistance programs.[26]

Besides the rates applied to the private facility, the rates applied to EV owners during home charging are essential to justify the economic gains of the spread between the two rates. The applied charge is a weighted average off-peak domestic time-of-use electric vehicle charging (TOU-EV-1) rate adapted from SCE's tariff book according to the season (SCE, 2019b), resulting in an energy price $P_{ev} = 0.1103$ \$/kWh.

### 3.2.3. DER parameters

Numerous parameters of technology and market data are needed to obtain reliable results according to the scenario. Capital and operational costs for DERs were obtained by selecting values from a list of options after extensive benchmarking. Two cost scenarios are defined to compare different cost reduction trajectories. First, in both exogenous and endogenous investment analysis, we adopt a conservative scenario in which we select mid-range values found in the literature with their public subsidies, if applicable. To complement the endogenous analysis, an optimistic scenario considering a significant cost decrease of DERs is assessed.

For the solar PVs, we take a peak efficiency of 19.1%, which corresponds to a multi-crystalline panel taking the highest market share globally (NREL, 2019). The investment costs per KW found in the literature range from 1250 to 3237 \$/kW[27] (Beck et al., 2017; Hanna et al., 2017; Cardoso et al., 2017; Fu et al., 2017; Tervo et al., 2018; Koskela et al., 2019; NREL, 2020). There is also a wide range of values for their lifetime, from 20 to 30 years. Finally, the following specifications were selected for the conservative scenario: 2100 \$/kW (Fu et al., 2017), 25 years of lifetime (Sheha and Powell, 2019) and 0.66 \$/kW per month (Mclaren et al., 2018) as operation and maintenance costs. In the optimistic scenario, we adopt the value of 1250 \$/kW in line with the cost projected by NREL (2020) for commercial PVs in their advanced technology scenario by 2025.[28]

Besides the market parameters, battery energy storage systems (BESSs) and EVs have extra technical parameters linked to the battery functioning compared to solar PVs. First, a fixed cost of \$500 (Beck et al., 2017) is established to account for the mandatory battery system costs regardless of the size of the battery, such as the initial installation labor and the structural support. The investment costs per kWh, as in the case of solar PVs, vary widely in the literature, from 350 to 1050 \$/kWh for lithium-ion battery technology (Hanna et al., 2017; Beck et al., 2017; Cardoso et al., 2017; IRENA, 2017; Doroudchi et al., 2018; Fu et al., 2018; Koskela et al., 2019). The selected value was 465 \$/kWh (Doroudchi et al., 2018). However, adding the lower bound of the subsidy offered by SCE's storage rebate incentive program, up to 250 \$/kWh (SCE, 2017), turns the final cost into 215 \$/kWh. In the optimistic scenario, the value of 100 \$/kWh was selected. This value is the goal of the battery industry for making electric vehicles competitive with internal combustion engine vehicles without subventions. Their lifetime varying from 5 to 15 years, we select 10 years (Sheha and Powell, 2019; Tesla-Powerwall, 2020); the fixed maintenance is already included in the investment costs per kWh value. Second, several technical parameters must also be defined. We thus set a charging and discharging efficiency of 90% (Tesla-Powerwall, 2020), a maximum charging and discharging rate of 30%, and a state of charge between 20% and 90% to avoid extra battery degradation.

In the case of electric vehicles, the costs will be associated with the installation of the charging station by the local facility while the vehicle itself is owned by the employees of the building. The level 2 charging stations, ranging from 4 kW to 20 kW, are mostly found in commercial buildings and workplaces due to the higher charging power needed to compensate for the shorter connection period compared to home charging. Here, we take a 7.7 kW DC bidirectional charging station, excluding the need for users to install an extra onboard charger to allow vehicle-to-grid capabilities when the station, not the vehicle, does the DC-AC conversion. Currently, there is no large-scale commercial production of bidirectional charging stations; for this reason, costs for bidirectional chargers come from expert insights. It is possible to order a charging station with the desired specifications for 3850 \$/station. CPUC gives 50% of its charging station base cost rebate via the SCE Charge Ready program for workplaces (CPUC, 2016); thus, the final price would be around 1900 \$/Station. The charging station cost in the optimistic scenario depends on the technological progress in the power electronics industry. We assume a similar cost reduction as in the battery case, and we adopt the value of 1,000 \$/Station without rebates. To calculate the investment costs per kWh as an input to the model (\$/kWh) defined by Eq. (A.3), it is necessary to define an average battery capacity according to the Californian scenario of the vehicles connected to each charging station at the facility. Calculating the top sold EV weighted average in California during 2018 according to IHS-Markit (2019), we obtain the value of 58 kWh battery per vehicle. It results in a cost of accessing the EV battery of 32.75 \$/kWh in the conservative scenario and 16.37 \$/kWh in the optimistic one, dividing the cost of installing a charging station per the average battery capacity. A lifetime of ten years and fixed operation and maintenance costs of 0.28 \$/kWh per month (10% of the investment costs per kWh per year) were also taken. Table 1 summarizes all the costs taken for the different DERs.

Specifically for EVs, there are several parameters to be defined with regard to the state of charge and connecting hours at the facility

[23] The detailed rate values during summer and winter periods are presented in Tables D.11 and D.12.

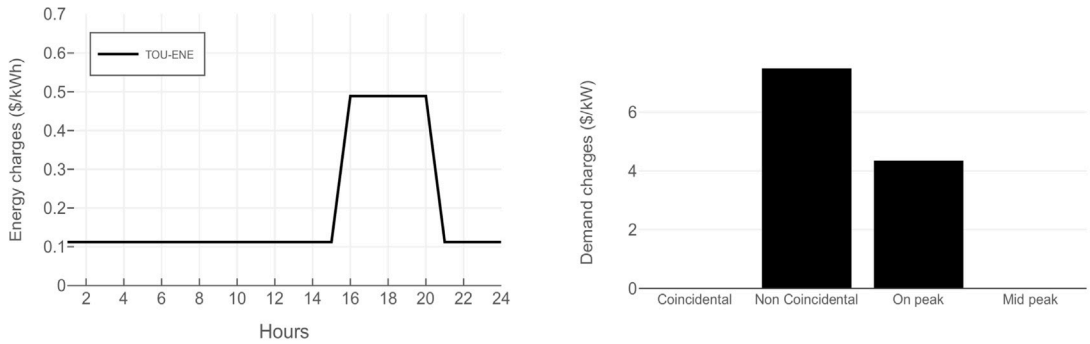
[24] The Table D.13 shows the complete list of coincidental hours adopted monthly by the utility.

[25] In SCE's C&I tariff book, the adopted retail tariffs TOU-ENE and TOU-CAP correspond to TOU-E and TOU-D while TOU-COIN is a counterfactual tariff based on coincidental demand charges. SCE proposed these tariffs TOU-D and TOU-E to frame better the grid constrained period and the cost of using the network by shifting the attributed on-peak period from around midday toward early evening. In addition, SCE customers are encouraged to compare their current energy costs to other rate options and select the best rate plan.

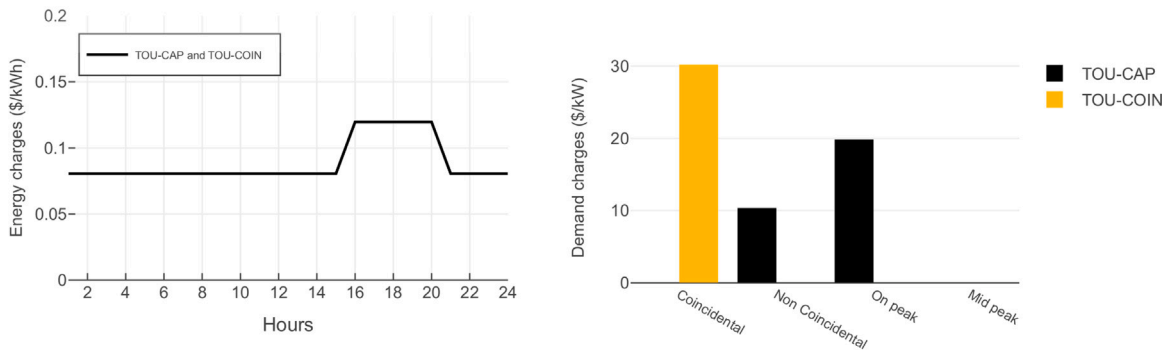
[26] In the case of feed-in-tariffs, in which the utility buys the excess energy from the PVs at a price equal or higher than the applied retail rate, the program called Renewable Market Adjusting Tariff (ReMAT) by CPUC to incentivize the adoption of small renewable generators (less than 3 MW) was suspended for all new contracts under SCE territory (CPUC, 2018). Regarding net-metering schemes, SCE gives the possibility of billing the net energy at a certain point in time via the program NEM 2.0 (SCE, 2021). However, an imminent change of this program toward a new NEM 3.0 may have a strong impact on the project's profitability (IOUs, 2021).

[27] More precisely, these values are calculated as \$/kWac, meaning that the investment already includes the power inverter to transform the direct current into alternate current to be used in a local grid.

[28] The lowest costs per kW of PVs are found in utility-scale projects by scaling up project size and portfolios. Since they are larger than commercial and residential PV projects, the great size enables them to reduce operation and maintenance expenses.




(a) Energy-based tariff during summer ($/kWh)




(b) Capacity-based and coincident peak tariff during summer ($/kW)

**Fig. 4.** Electricity tariff formats.

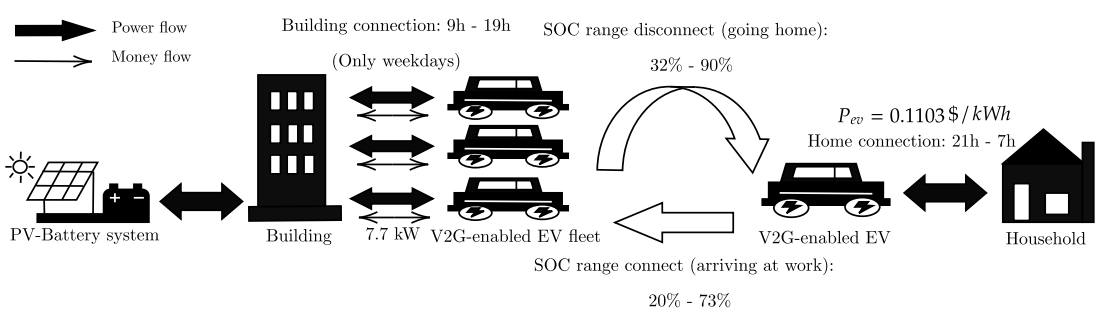



**Fig. 5.** Electric vehicle parameters and time schedule.

or home. Similar to the BESS, the adopted charging and discharging efficiency is 90%, the allowed state of charge ranges between 20% and 90% to avoid further degradation. One real limitation to the minimum state of charge is ensuring enough energy for the EVs to make their trip back home safely. In California, a battery-electric vehicle goes on average 42 kilometers a day, meaning 21 kilometers per trip (INL, 2015), which accounts for 8 kWh assuming an EV consumes 19 kWh/100 km. Consequently, the minimum state of charge during the disconnection anywhere is the standard 20% plus 12% to ensure at least round trip, so the final value is 32%. By contrast, the minimum state of charge to connect at the facility grid is 73%, which accounts for the average consumption to make the trip from home to the commercial building plus a small reserve margin.

In our scenarios, the home charging episodes occur between 9 PM and 7 AM, which is when the EV is parked at home under the off-peak tariff period with cheaper electricity, whereas the connection at the facility grid occurs at 9 AM and they disconnect at 7 PM (Stadler et al., 2013). The EVs are not connected to the buildings on the weekends for two main reasons. First, most of the employees would not be working in offices, warehouses, and retails. Second, defining the random mobility patterns during these days for the remaining building types (restaurants and malls) lies outside the scope of this paper. Fig. 5 summarizes all the parameters visually for the EV case. The final parameters model the battery degradation according to Eq. (A.4): the capacity loss per normalized Wh is $8.70 \cdot 10^{-5}$ , the future replacement cost is 200 $/kWh for the conservative scenario and 100 $/kWh for the optimistic one.

## 4. Results

The following section presents and justifies the analysis of both exogenous and endogenous investments. We focus our analysis on four of the metrics in Fig. 1: net present value, avoided costs, cost-shifting, and EV remuneration. Since charge and discharge strategies and demand reduction will be implicit in the calculation of the chosen metrics, they will be mainly used to explain the dynamics behind the primary metrics.

### 4.1. Exogenous investment

The main objective of the exogenous investment is to fix the amount of DERs installed beforehand (see Appendix B for additional DER sizing

**Table 1**
Adopted DER costs.

| | Solar PV | Battery | Electric vehicles |
|---|---|---|---|
| Fixed cost | – | Cons[a]: $ 500<br>Opt: $ 0 | – |
| Cost per kW(h)<br>(After subsidies) | Cons: 2100 $/kWac<br>Opt: 1250 $/kWac | Cons: 215 $/kWh<br>Opt: 100 $/kWh | Cons: 32.74 $/kWh<br>Opt: 16.37 $/kWh |
| Lifetime | 20 years | 10 years | 10 years |
| O&M (per month) | 0.66 $/kW | 0 | 0.28 $/kWh |
| Subsidy | – | Cons: 250 $/kWh<br>(SCE incentive program)<br>Opt: – | Cons: $1950 (50% of station cost)<br>(SCE workplace rebate)<br>Opt: – |

[a]The acronym 'Cons' stands for the conservative scenario and 'Opt' for the optimistic scenario.

details). The model chooses the discharging and charging strategies to minimize the total cost, thus studying the variability of these strategies according to each tariff structure independently. The sensitivity to the tariff design is critical to measure how the strategies differ by isolating the impact of adjusting tariffs. The exogenous investment isolates the impact of adjusting tariffs while having a fixed amount of installed DER. In the current context, it can be seen as a change of regulation in which customers are obliged to move from one tariff scheme to another (after the grandfathering period) after investing in DERs. An example would be a customer under an energy-based tariff with a considerable amount of installed PV who now faces high demand charges under a capacity-based tariff. Then, it might not necessarily have the lowest possible cost at the start. Nevertheless, the exogenous sizing is unlikely in real life since one DER size does not fit all tariffs, it allows to measure the effect on customer investments.

**Table 2**
Average percentage total electricity costs change (%).

| PV+BESS | | TOU-CAP | TOU-COIN | TOU-ENE |
|---|---|---|---|---|
| | Baseline | | | |
| | TOU-CAP | −50.2 | −49.9 | −58.9 |
| | TOU-ENE | −43.9 | −43.3 | −51.4 |
| PV+EV | | TOU-CAP | TOU-COIN | TOU-ENE |
| | Baseline | | | |
| | TOU-CAP | −37.2 | −35.5 | −48.2 |
| | TOU-ENE | −32.9 | −30.9 | −42.3 |
| PV+EV+BESS | | TOU-CAP | TOU-COIN | TOU-ENE |
| | Baseline | | | |
| | TOU-CAP | −46.7 | −42.6 | −55.1 |
| | TOU-ENE | −41.0 | −37.0 | −48.2 |

#### 4.1.1. Net present value

This section assesses the private financial value of installing DERs under the discussed electricity rates. The net present value (NPV) is an economic indicator of whether the investment made by the private facilities will be profitable.[29] Before calculating the NPV, it is essential to analyze the changes in total electricity costs as we move from one base case without DERs under the former tariff type to one with DERs installed under all presented rates.[30]

Tariff design has a strong influence on battery and EV charging and discharging strategies, which in turn affect the electricity costs. The main objective is to charge the battery and EV during off-peak periods to achieve energy arbitrage objectives and not to compromise private peak demand during that process. With respect to discharging strategies, there are several incentives to adopt storage, such as energy arbitrage, offset coincident peak Maximum Demand Charges (MDC), non-coincidental MDC, and on-peak MDC. These are all summarized in Table C.10 along the time at which they occur for each tariff. More details on the charging and discharging episodes can be found in the Appendix C.

Table 2 gives the result for the four technology scenarios where general observations can be made, and the average total electricity costs are available in Table D.17. First, the PV+BESS is the scenario where there is the most significant cost reduction, followed closely by the PV+EV+BESS. BESSs have a spillover effect on EVs, supporting them to discharge more than they would if they were alone. The gap between electricity cost reduction between those two scenarios (PV+BESS and PV+EV+BESS) thus decreases. The PV generation is not synchronized with on-peak demand periods under these tariffs, reducing the total electricity savings. Under the capacity type, the cost reductions are almost the same as for coincident peak tariffs due to a similar discharging strategy being adopted when there is no PV production at the end of the afternoon. Finally, under the energy tariff, the electricity cost shortfall outruns the other ones since the PV generation is highly valued.

According to our calculations, the most substantial positive return is under the TOU-ENE tariff due to the high contribution of PV generation to decrease energy charges even without any complementary financial help such as feed-in tariffs or net-metering schemes. However, PVs seem to be oversized under all the other rates, leading to negatives returns and implying the need for storage.

Second, the BESS coupled with PVs is the best scenario considering NPV under all the tariffs. The same results are applied to the storage mix but with a lower return. We would expect considerably higher returns when moving toward the coincident capacity tariff. However, in some facilities, the load at the coincident peak time is so small that even with a 100% offset of the demand, the total energy costs with an installed DER would exceed the total energy costs of not having any DER at all.

Third, the EVs as the standalone storage have the worst performance in all the scenarios observed in this NPV analysis. EV charging with PV surplus is not enough to financially compensate the high investments made in solar panels and charging stations. Moreover, batteries perform economically better than EVs under all tariffs due to the higher availability and extended discharging periods. They also present the lowest financial return under coincidental tariff because their capability to offset demand is directly linked to the utility's coincidental hour. During half of the year, the coincidental hour is around 7 PM, meaning that EVs cannot discharge at this time since they are already disconnected from the building. All the results concerning net present values using the scenario without any DER installed for each tariff as the baseline are summarized in Table 3.

[29] We considered a nominal discount rate of 8%, a time horizon of 20 years (the lifetime of solar PVs), and an inflation rate of 1.5%. For a yearly time period i, the net present value is calculated by: $\sum_{i=1}^{20} \frac{Annualized\ cash\ flow \cdot (1+inflation)^i}{(1+nominal\ discount\ rate)^i}$.

[30] For baseline tariff j ∈ TOU-CAP, TOU-ENE and tariff k ∈ TOU-CAP, TOU-COIN, TOU-ENE, the percentage change in total electricity costs (TEC) of moving from the baseline tariff j to the new tariff k with technology i ∈ PV+BESS, PV+EV,PV+EV+BESS is calculated by: $\frac{TEC_k^i - TEC_k^{Base}}{TEC_j^{Base}}$.

**Table 3**
Net present value by rates and technology scenarios ($).

| Net present value with Solar PV+BESS | | | |
|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE |
| Mean | −17,518 | −21,543 | 33,772 |
| (St. Dev.) | (18,286) | (35,044) | (20,822) |
| #> 0[a] | 1 | 2 | 5 |
| **Net present value with Solar PV+EV** | | | |
| | TOU-CAP | TOU-COIN | TOU-ENE |
| Mean | −71,684 | −89,815 | −17,767 |
| (St. Dev.) | (40,185) | (50,996) | (16,246) |
| #> 0 | 0 | 0 | 0 |
| **Net present value with Solar PV+EV+BESS** | | | |
| | TOU-CAP | TOU-COIN | TOU-ENE |
| Mean | −25,651 | −53,365 | 19,142 |
| (St. Dev.) | (21,677) | (37,884) | (17,814) |
| #> 0 | 0 | 0 | 4 |

[a]#> 0 values counts the facilities with positive NPVs.

**Table 4**
Average peak demand reduction.

| | TOU-CAP | TOU-COIN | TOU-ENE |
|---|---|---|---|
| Average system peak demand reduction (%) | | | |
| PV+BESS | −38.7 | −44.5 | −42.8 |
| PV+EV | −13.5 | −18.8 | −24.5 |
| PV+EV+BESS | −33.5 | −30.1 | −37.5 |
| Average private peak demand reduction (%) | | | |
| PV+BESS | −47.5 | −8.3 | −45.4 |
| PV+EV | −27.2 | −17.3 | −27.2 |
| PV+EV+BESS | −44.1 | −20.3 | −43.1 |

### 4.1.2. Avoided costs

The total avoided costs will, in theory, be directly linked to the demand reduction during system on-peak hours (5–8 PM) depending on the weighting on these periods for each tariff. Following the method proposed, we also study two different cases to calculate the facilities' average avoided costs: Case 1, when the facility peak day overlaps with the typical avoided costs for a weekday, and Case 2, when the private facility peak overlaps precisely with the system peak avoided costs profile.

We analyze three different technology scenarios, comparing them to the base case scenario without any DERs under our three representative tariff structures. The first observation is that peak demand reduction due to PV generation is not negligible due to the synchronization of the load profile with the PV generation. The highest demand hours occur mostly when the PV generates electricity, leaving few early morning and early evening hours to be offset by storage. The system peak time is less affected by the PVs because it occurs when the generation starts to come down. However, the private peak is also relatively reduced.

In Table 4, the PV+BESS scenario shows the highest percentage reduction for system peak demand and for private peak demand except under coincident peak tariffs.[31] Under TOU-COIN, the BESS is charged with a significant amount of energy during non-coincident periods to offset the demand of coincident periods creating a higher private demand than before but in another time window. Regarding PV+EV+BESS, the demand reduction is similar to the PV+BESS scenario because now the battery supports the EV discharge before departure, crossing the threshold where the EV battery use cost (degradation plus energy) exceeds the gains.

[31] Tables D.14–D.16 are provided for more details about the monthly demand reductions according to the technology scenarios under different tariffs.

**Table 5**
Average avoided costs — Case 1 ($).

| | TOU-CAP | TOU-COIN | TOU-ENE |
|---|---|---|---|
| Avoided costs of solar PV+BESS — Case 1 | | | |
| Total mean | 17,501 | 17,589 | 17,201 |
| (St. Dev.) | (8,503) | (8,431) | (8,400) |
| Energy | 9,042 | 8,644 | 8,767 |
| (St. Dev.) | (4,447) | (4,348) | (4,332) |
| Capacity | 8,459 | 8,684 | 8,434 |
| (St. Dev.) | (4,090) | (4,177) | (4,108) |
| Avoided costs of solar PV+EV — Case 1 | | | |
| Total mean | 10,104 | 12,436 | 14,826 |
| (St. Dev.) | (5,534) | (5,962) | (7,427) |
| Energy | 6,578 | 6,798 | 7,326 |
| (St. Dev.) | (3,460) | (3,336) | (3,735) |
| Capacity | 3,525 | 5,638 | 7,500 |
| (St. Dev.) | (2,081) | (2,676) | (3,740) |
| Avoided costs of solar PV+EV+BESS — Case 1 | | | |
| Total mean | 14,459 | 15,067 | 16,127 |
| (St. Dev.) | (7,448) | (7,639) | (8,308) |
| Energy | 8,078 | 7,732 | 8,355 |
| (St. Dev.) | (4,160) | (3,950) | (4,267) |
| Capacity | 6,381 | 7,334 | 7,771 |
| (St. Dev.) | 3,299 | (3,739) | (4,049) |

**Table 6**
Average cost-shifting measures by technologies and tariffs — Case 1 ($).

| | TOU-CAP | TOU-COIN | TOU-ENE |
|---|---|---|---|
| PV+BESS | 8,004 | 7,583 | 12,542 |
| (St. Dev.) | (5,433) | (4,026) | (6,419) |
| % of savings | 31.4 | 30.1 | 42.2 |
| PV+EV | 8,936 | 5,412 | 9,611 |
| (St. Dev.) | (5,635) | (2,585) | (5,293) |
| % of savings | 46.9 | 30.3 | 39.3 |
| PV+EV+BESS | 9,381 | 6,420 | 11,770 |
| (St. Dev.) | (5,767) | (2,966) | (5,840) |
| % of savings | 39.3 | 29.9 | 42.2 |

When BESS is present, the TOU-ENE and TOU-CAP tariffs effectively enhance the demand reduction during the system and private peak times due to their incentive to discharge during the on-peak time. EVs alone offset more demand under the energy tariff TOU-ENE compared to TOU-CAP since they have a low discharge power rate under this capacity tariff.

Recalling that the PV tends to offset a significant amount of the demand in the middle of the day, the discharge strategies of energy and capacity tariffs will be similar for case 1 using BESS. Their on-peak periods are the same, which increases the avoided costs, as it gives more incentive to discharge during this time window. The coincident peak rate increases the avoided costs even more by better framing the specific time window with the highest avoided capacity costs for the system. Contrary to the PV-only scenario in which most of the avoided costs are energy-related (67% against 32% from capacity-related costs as shown in Boampong and Brown (2020)), in the BESS case, the capacity costs account for almost half of the total in all tariffs. This fact indicates that the battery is discharging during time periods when the system is constrained and has the highest avoided capacity costs and charging when there are the lowest capacity costs (see the average result over 20 years for PV and PV+BESS in Table 5).

EVs have the lowest total avoided costs among all the storage technologies, where most of those costs are energy-related, while the capacity-related avoided costs appear more during summer periods. Because EVs are not present during weekends in our scenarios, the energy not exchanged with the grid will reduce the total avoided costs for the EV alone compared to the other scenarios. They present low avoided costs under the capacity tariff, but the performance is better under coincidental and energy tariffs. According to their discharging

**Table 7**
Average DER amount in endogenous case.

| | Conservative scenario | | | Optimistic scenario | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| PV (kW) | 32.2 | 0.0 | 77.2 | 137.8 | 83.8 | 145.8 |
| (St. Dev.) | (21.0) | (0.0) | (25.3) | (66.1) | (38.2) | (73.8) |
| #> 0[a] | 5.0 | 0.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| BESS (kWh) | 83.2 | 183.2 | 235.2 | 418.6 | 258.8 | 442.4 |
| (St. Dev.) | (65.4) | (103.6) | (73.0) | (207.9) | (152.4) | (219.7) |
| #> 0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| EV (kWh) | 116.3 | 72.3 | 273.7 | 77.7 | 0.0 | 0.0 |
| (St. Dev.) | (58.5) | (29.2) | (273.1) | (47.5) | (0.0) | (0.0) |
| #> 0 | 3.0 | 4.0 | 3.0 | 3.0 | 0.0 | 0.0 |

[a] #> 0 values count the facilities with positive DER capacity installed.

strategy, they have more incentive to offset demand during a short period or arbitrage energy along the day, leading to higher avoided costs. The combination EV+BESS performs mid-way between the other two technology scenarios with storage, as shown in Table 5.

With regard to cases 1 and 2 (Table D.18), the main difference lies in the results of private facility week day multiplied by system peak day and private facility peak day multiplied by system peak day profile. Usually, when the two peak days coincide, the avoided costs will be high when the avoided capacity costs are higher in this case. Nevertheless, this will depend on when the load peak occurs in the facility and whether coincident peak tariffs are applied.

First, if the private peak load occurs in the early morning, the facility will tend to offset it during the day, leaving less energy to be discharged in the late afternoon, as occurs on weekdays. Hence the avoided costs during a weekday would be higher than the peak day.

Second, coincident peak tariffs will postpone the charge to later hours just before the coincidental period. The avoided costs during the discharge for the private peak days will not outweigh the costs for the charge during the weekday. The difference between avoided costs for discharge and cost of charge between the two cases (case 2 minus case 1) will therefore be negative.

#### 4.1.3. Cost-shifting

Table 6 shows, for case 1, the cost-shifting in absolute values and relative to the corresponding private gains. The capacity tariff has significantly lower cost-shifting than the energy tariff since the PV does not bring as high electricity gains in this case. For instance, the increased private gains outweigh the higher avoided costs under the energy tariff. Regarding the coincident peak tariff, the cost-shifting is the lowest in absolute values due to higher avoided costs and lower electricity savings than the capacity tariff TOU-CAP. This fact happens because batteries and EVs are incentivized to discharge during the variable grid-constrained periods and increase the avoided costs. While the avoided costs remain practically the same for batteries, they increase for EVs, leading to lower cost-shifting values. This last finding is interesting, showing that EVs can increase both electricity savings and avoided costs. This makes them suitable candidates to incentivize private gains and alleviate grid constraints at the same time under this type of tariff.[32]

#### 4.1.4. Value created by electric vehicles

Although the scenarios with negative NPV are unlikely, the analysis of the EV revenue under different tariffs is still pertinent. The goal is to identify preliminary evidence from this sensitivity analysis before the endogenous investment assessment. In general, according to Fig. 6, the value created by energy services compared to the sum of compensations is the highest under coincident demand tariff for both cases (PV+EV and PV+EV+BESS), where EVs can offset demand charges under a shorter period compared to on-peak demand and even non-coincidental demand, which can last for several hours. Therefore, under the capacity tariff (TOU-CAP), EVs without battery support are not well-adapted to covering all this time window to offset demand. For the energy tariff (TOU-ENE), the battery degradation component exceeds all others, suggesting that more kWhs needing financial compensation are exchanged via the EV. Unlike the many studies on EVs providing energy services to the grid, we consider battery degradation an important factor influencing remuneration. Yet if the capacity loss per normalized Wh of $8.70 \cdot 10^{-5}$ and future replacement cost of 200 $/kWh are considered out of date, a share of the total amount can still be part of the sharing of value between the facility and EV owners.

The number of EVs connected to the grid also directly influences the total revenue per vehicle in both scenarios. For instance, the PV+EV scenario remuneration per EV is considerably lower than the PV+EV+BESS one due to the higher number of vehicles present (twice as many). The competition between them thus decreases the amount received by any vehicle.

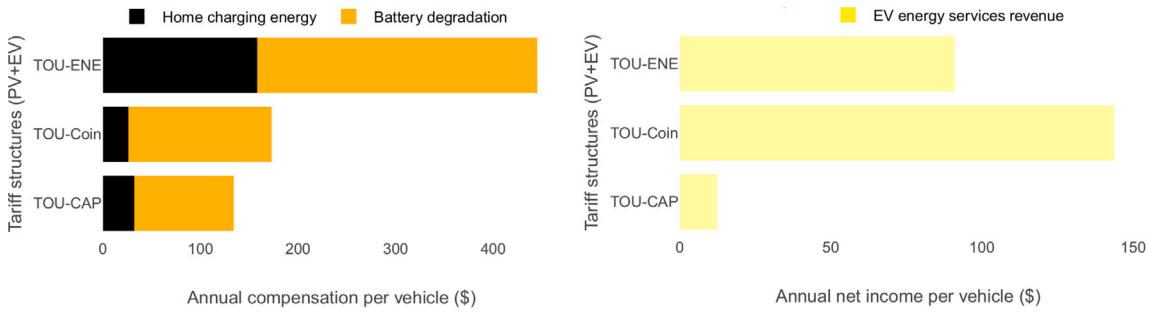
### 4.2. Endogenous investment

This last section considers the endogenous investments, i.e., letting the model choose the optimal amount of DER for each facility to minimize their total costs. The previous exogenous assessment was made to explore the effects of changing tariffs and their influence on the discussed measures: private financial value, avoided costs, cost-shifting, and EV remuneration. Now, this section will extend the analysis by demonstrating what investments facilities might make, acting rationally. Two DER cost scenarios are discussed for the endogenous investments: a conservative and an optimistic one. In the first scenario, we select mid-range values found in the literature with their public subsidies. The latter accounts for a considerable decrease in DER prices due to technological progress and learning-by-doing effects.

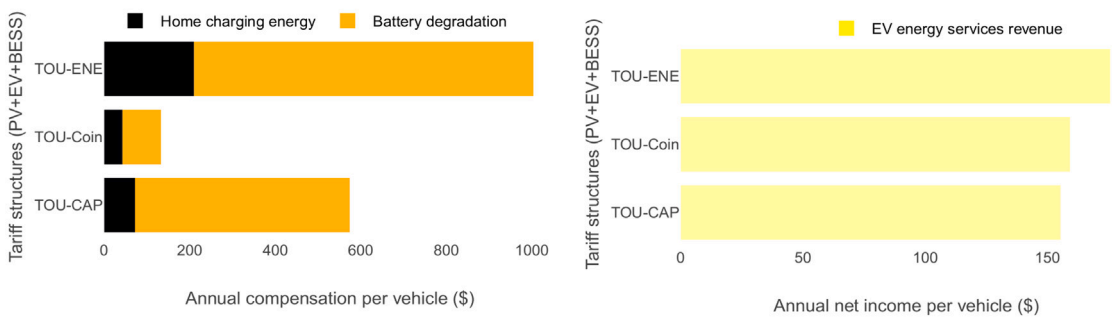
Table 7 shows the mean capacity installed in the facilities of each DER type and how many facilities choose to install it by the tariff. Regarding the conservative scenario, the energy tariff TOU-ENE incentivizes the highest amount of PVs to be installed, confirming the high valuation of solar PV generation under this type of rate. No PVs were installed in any of the facilities under coincident tariffs due to the low demand offset during the coincidental period. The model also chooses to use stationary batteries in all facilities both to offset maximum demand charges and arbitrage energy between different time windows. Under the capacity rate, less storage is needed to be profitable due to the lower on-peak demand to be reduced at these hours of the day. For energy rates, the opposite holds, as the TOU-ENE tariff needs more storage to arbitrage energy toward late afternoon when there is not enough solar PV electricity generation. Under coincident peak tariff class, the number of facilities adopting EVs is the highest among all tariffs, in which four buildings adopted this type of storage. This shows that they are suitable candidates for offsetting coincidental maximum demand charges during a short time window; however, the amount of kWh accessed is highly dependent on the coincidental hours. If the coincidental hour is fixed at 6 PM along the year, for example, instead of being variable between 5–8 PM, the amount of kWh of EVs accessible would be almost seven times higher and they would be present in all buildings.[33] In this matter, Table 7 should be interpreted carefully. Although the number of facilities installing EV charging stations is the highest under TOU-COIN among all tariffs for both coincidental hour scenarios, the mean capacity of EVs is highly variable.

[32] The results of case two in Table D.19 are analogous to case one, and the qualitative analysis is roughly the same.

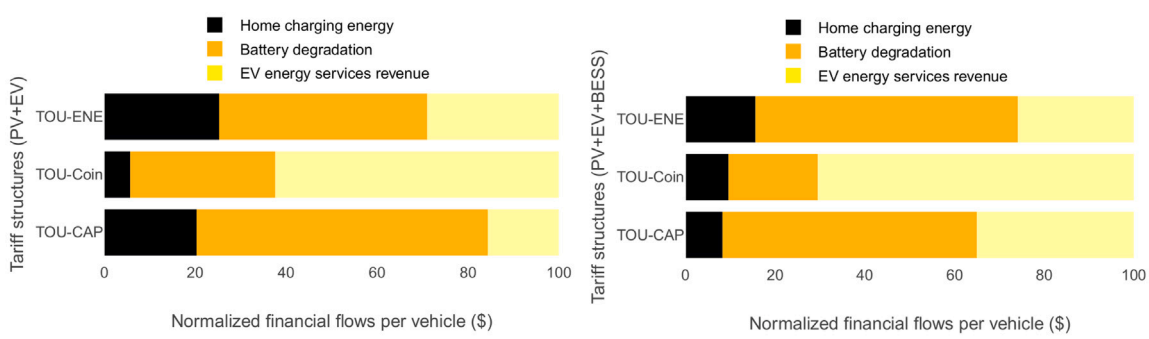
[33] An average of 475.4 kWh of EVs is invested by the buildings under TOU-COIN if the coincident hour is fixed at 6 PM as shows Table D.20.




(a) Average EV compensation (left) and net income (right) per vehicle per year - PV+EV case ($).




(b) Average EV compensation (left) and net income (right) per vehicle per year - PV+EV+BESS case ($).




(c) Normalized financial flows per vehicle per year - PV+EV case (left) and PV+EV+BESS case (right). ($).

**Fig. 6.** Average EV financial flow breakdown per vehicle — Exogenous case.

As expected, due to the cost reduction of DERs, the total amount of installed DER increases considerably in the optimistic scenario. Solar PVs are now adopted under all types of tariffs, including the TOU-COIN and stationary batteries are the main type of storage. Even with equivalent cost reduction, EVs are not preferably adopted by buildings. For instance, under TOU-COIN and TOU-ENE, batteries substituted all the available vehicles. It is now possible for the buildings to offset all the coincidental demand using only cheap batteries instead of EVs that are away when coincidental hours arise at 7 PM during half of the year. The availability is also linked with the investment under TOU-ENE tariff since now energy arbitrage can be cheaply done on all week days and weekends.

Regarding private financial returns, we analyze the average electricity cost reduction and the net present value considering all investment costs (see Table 8). Although in some cases with exogenous investments, the electricity cost reduction might be greater, the total cost also depends on the DER costs and EV expenditures. In the endogenous case, all these cost terms will be minimized to have the highest possible NPV. Energy tariffs have, in general, the highest electricity reduction and NPV due to the solar PV generation being in phase with the load profile. Economic gains under the capacity tariff are moderately reduced when the solar PV does not efficiently reduce non-coincidental demand. In these cases, the facilities, therefore, rely on storage to offset on-peak and non-coincidental demands. Still, at some point, the costs of storage outweigh the gains of reducing the demand.

These two facts thus bound the maximum NPV considerably lower than the corresponding energy tariff, the exception being coincident peak tariffs. Looking closer at this tariff, TOU-COIN rate shows a higher NPV than TOU-CAP with almost the same electricity change. TOU-COIN presents the highest NPV among all tariffs due to the reduction of electricity costs with smaller investments; however, the situation changes between the two cost scenarios. When buildings manage to offset 100% of coincidental demand using cheap battery storage, the NPV reaches a maximum in which no additional investment in storage brings more financial benefits. This constraint prevents a significant increase of NPV under TOU-COIN when compared to other tariffs,

**Table 8**
Private financial gains — Endogenous case.

| | Conservative scenario | | | Optimistic scenario | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| Average total electricity costs — Endogenous case ($) | | | | | | |
| Basecase | 50,144 | 43,729 | 57,517 | 50,144 | 43,729 | 57,517 |
| (St. Dev.) | (23,538) | (20,931) | (27,012) | (23,538) | (20,931) | (27,012) |
| With DER | 37,554 | 30,887 | 27,685 | 13,020 | 16,927 | 12,174 |
| (St. Dev.) | (17,452) | (13,845) | (16,713) | (6,341) | (8,956) | (5,374) |
| Average percentage total electricity costs change — Endogenous case (%) | | | | | | |
| Baseline | | | | | | |
| TOU-CAP | −24.94 | −24.97 | −60.89 | −73.87 | −53.15 | −89.86 |
| TOU-ENE | −22.42 | −21.39 | −52.77 | −64.68 | −45.72 | −78.35 |
| Average net present value (NPV) — Endogenous case. ($) | | | | | | |
| Mean NPV | 30,718 | 77,518 | 55,558 | 160,710 | 150,596 | 248,208 |
| (St. Dev.) | (22,225) | (47,911) | (29,053) | (77,811) | (84,651) | (118,181) |
| #> 0[a] | 5 | 5 | 5 | 5 | 5 | 5 |

[a] #> 0 values count the facilities with positive NPV.

**Table 9**
Average avoided costs and cost-shifting — Endogenous case. ($)

| | Conservative scenario | | | Optimistic scenario | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| Avoided costs — Endogenous case 1 | | | | | | |
| Total Mean | 6,278 | 9,363 | 22,127 | 33,330 | 20,450 | 34,390 |
| (St. Dev.) | (4,005) | (5,405) | (10,142) | (16,158) | (9,901) | (17,196) |
| Energy | 2,625 | 2,575 | 8,645 | 15,558 | 9,327 | 16,129 |
| (St. Dev.) | (1,713) | (1,573) | (3,484) | (7,483) | (4,415) | (7,887) |
| Capacity | 3,653 | 6,789 | 13,482 | 17,772 | 11,122 | 18,261 |
| (St. Dev.) | (2,434) | (3,839) | (7,294) | (8,701) | (5,487) | (9,350) |
| Cost-shifting — Endogenous case 1 | | | | | | |
| Total Mean | 6,312 | 3,479 | 7,704 | 3,794 | 6,353 | 10,953 |
| (St. Dev.) | (4,338) | (2,227) | (1,972) | (5,452) | (3,989) | (5,937) |
| % from savings | 50.1 | 27.1 | 25.8 | 10.2 | 23.7 | 24.2 |

especially TOU-CAP. Finally, the highest NPV in the optimistic scenario is found to be the TOU-ENE tariff due to the high economic return of solar PV generation.

As expected from the exogenous results, the highest avoided costs are found under energy tariff in which there is more solar PV generation and more installed storage to arbitrage energy toward on-peak periods. In the exogenous case, the sometimes oversized solar exports contribute to the higher share of energy-related avoided costs. In comparison, in the endogenous case, the capacity costs are the highest share under all tariffs due to the proportionally higher storage share than solar PVs. Unsurprisingly, under the energy tariff TOU-ENE, the avoided costs are greater than the other ones justified by the higher investment in storage and solar PV. Even so, the main incentive to invest in storage is to reduce maximum demand charges, for this type of tariff, the spread between on-peak and off-peak is reasonably high. This justifies the adoption of more storage than the capacity tariff.

Cost-shifting issues are more critical among energy tariff due to more significant private savings, as shown in Table 9. In the optimistic scenario, cost-shifting concerns increase substantially, except for TOU-CAP, driven by an increase in DER investment for all tariffs. The avoided costs increase considerably more than the savings from reduced electricity consumption, reflecting a significant decrease in absolute and relative cost-shifting values for the capacity tariff. Otherwise, in the energy rate case, the private savings and total avoided costs values grow at a similar rate, contributing to cost-shifting. Finally, the coincident peak tariff follows the same trend as the energy tariff, for which we obtained the second-lowest cost-shifting among all rates. The results of case 2 for the endogenous case where the system peak day coincides with that in the facility are shown in Table D.21, and they are qualitatively analogous to the exogenous case.

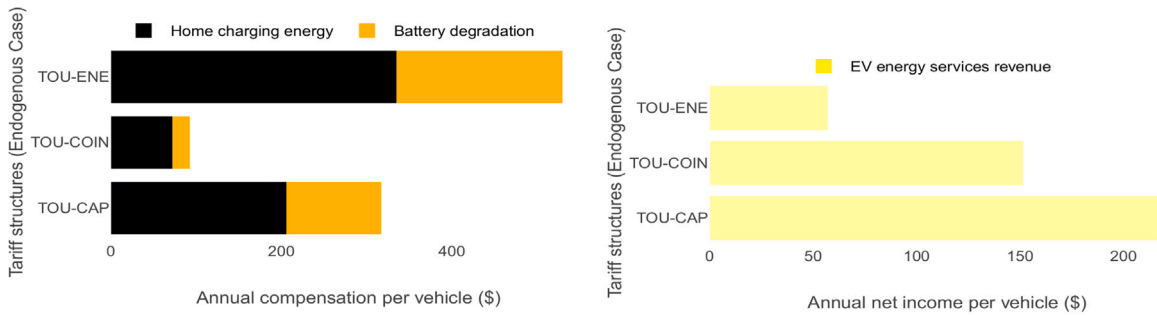
The last point to be analyzed is the EV net income for the endogenous case shown in Fig. 7 with more numerical details present in Table D.22. The endogenous investment will install the optimum amount of charging stations in the facilities to minimize their costs, so the remuneration of the EVs is a result of the optimization problem. Consequently, as opposed to batteries, charging stations were not installed in all the facilities according to each tariff structure studied in the conservative scenario. First, under capacity tariff, the total net income and the net income per vehicle are the highest, demonstrating the ability of EVs when coupled with stationary batteries to offset demand during an extended period. Under energy tariffs, the net income from energy services to the facility is the smallest share among all tariffs due to the competition from stationary batteries, which are more cost-efficient on the energy arbitrage task since they are present all day and during the weekends. Finally, under coincident peak tariffs, the stations enable the EVs to provide high value to the facilities by offsetting the coincident peak demand. The TOU-COIN rate shows the highest number of facilities adopting EVs and an annual average net income of $ 151.5 per EV, in which the highest share of the remuneration does not depend on battery degradation and electricity home pricing.[34] Finally, the financial flow is notably reduced in the optimistic scenarios as batteries are prioritized over EVs. Only under TOU-CAP the vehicles still appear as electric storage due to their synergy with batteries, but BESS are by far the primary storage source. In this case, with a net income of around $ 25, the attractiveness of providing this type of energy service may not be enough to convince EV owners.

## 5. Discussion and policy implications

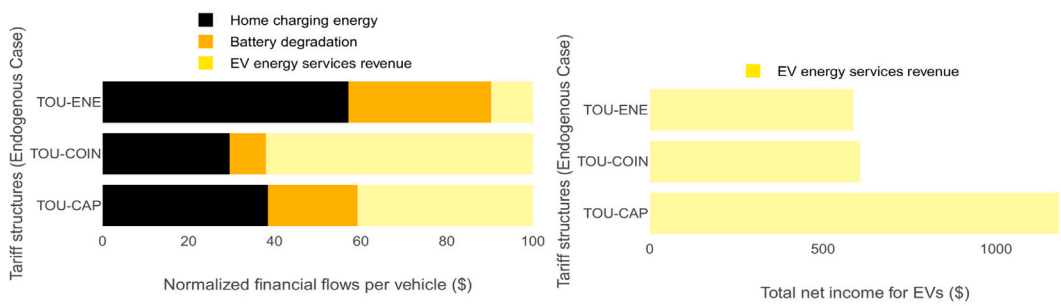
The development of smart-charging and vehicle-to-grid technologies reinforces the concept of using the EV as a DER. Endogenous investment analysis confirms that if commercial buildings have the possibility to install bidirectional charging stations to reduce the electricity bill, this would be profitable, especially under conservative cost scenarios (refer to Table 7). The inclusion of EVs in the DER portfolio alongside batteries and solar PVs expands the investment choices that heterogeneous buildings may have, consequently increasing the number of profitable scenarios for them. In all tariff scenarios in which EVs were present, a positive net income was observed for EV owners. This indicates that the episodes of charging at home and discharging in the commercial facility grid surpassed the ones of charging using commercial grid electricity and discharging at home. Even though solar electricity was available to charge the vehicles during their parking time, this locally generated electricity was not often used to charge them. This finding suggests that the synchronization between EVs and solar PVs in commercial buildings as the one found in Kuang et al. (2017) highly depends on the possibility to arbitrage energy from another source, for instance, EV owners home energy. A home time-of-use tariff set with a low off-peak rate can be a fair economic signal to drive the vehicle charging and alleviate grid congestions, but it will undermine the synergy between EVs and PVs.

It is essential to point out that the revenues obtained by EV owners rely on the hypothesis of systematic charging episodes at home, which has been found inaccurate from analysis of real-life EV driving and charging behavior (Western Power Distribution, 2019). EV owners should be incentivized to connect their vehicles more often to their home charging infrastructure to ensure energy arbitrage and follow-up revenue. The annual net income per vehicle found, which varied

[34] The net income is even higher when coincidental hours defined by the system operator arise sooner, in the case of fixed coincidental at 6 PM, it can reach around $426 per vehicle. The Table D.23 compares the average financial flow in those two cases for the conservative and optimistic scenario.




(a) Average EV compensation (left) and net income (right) per vehicle per year - Endogenous case.




(b) Normalized financial flows per vehicle per year (left) and total net income for EVs (right) - Endogenous case. ($)

**Fig. 7.** Average EV financial flow breakdown per vehicle — Endogenous case (Conservative scenario).

between $57 and $218 with the highest revenue found under TOU-CAP, illustrates the drawback of assessing theoretical remuneration for bill management services based on energy storage analysis as in Thompson and Perez (2020). The final remuneration is strongly dependent on which tariffs the facilities and vehicle owner's home are under and the specific constraints of vehicles such as availability. Energy services could be stacked, or the revenue split strategy between parties could be reviewed to increase EV remuneration using vehicle-to-grid services. First, regarding stacked services, in Black et al. (2020) a demonstration project in California showed the viability of using EV fleets to manage the facility electricity bill via demand reduction and provide ancillary services to the local utility. Another option could be to reevaluate the fifty-fifty split of revenue. In our analysis, the cost of installing a charging station is fully recovered via direct energy savings brought by EVs with bidirectional capabilities; however, charging stations in commercial facilities may have a positive effect on attractiveness to customers and employee satisfaction. These effects can have a beneficial effect on the general facility budget, allowing them to reduce their share of the value created by EVs.

General policy recommendations to regulators can be made using tariffs as instruments to push certain technologies forward. Energy tariffs provide the highest incentive to invest in solar PV production and will often be profitable to private facility investors. Even so, this is the worst case for cost-shifting in both the conservative and optimistic scenario of DER costs. If a local regulator seeks to increase the share of solar generation in the energy mix, a first step would be to incentivize energy tariff adoption. However, if high cost-shifting values are already present, adopting a coincident peak tariff can alleviate this issue in the short term. Finally, if the average cost of DERs continues to fall quickly, the capacity tariff would be an alternative to slow down cost-shifting increases due to high DER penetration. This is the only case in which the growth of avoided costs could outweigh the increase in cost savings, showing that the trade-off between maximizing avoided costs and minimizing cost-shifting found by Boampong and Brown (2020) should be nuanced under capacity tariffs in an optimistic cost scenario. The regulatory changes of this nature should be carefully planned since for a fixed investment, solar PV adopters would incur high financial losses when moving from an energy tariff to another with high weight in demand charges (as shown Table 2). Here, another trade-off between reducing cost-shifting levels and reducing solar PV revenues is observed.

## 6. Conclusion

This study describes how electricity rates influence crucial elements to be considered before investing in DERs at a private facility and how they can affect cost recovery from the utility's perspective. We considered several factors in our analysis, e.g., charging and discharging strategies, demand reduction, net present value, avoided costs, cost-shifting, and EV remuneration in two different types of investments: exogenous and endogenous. We simulated different technology combinations of PVs, BESSs, and EVs to assess the private investment part and the avoided cost model to account for the impact on the utility side. First, we considered the exogenous investment to understand the underlying mechanism in which the DER management system reacts under different price signals, i.e., distinct tariff designs. In addition, this type of investment is useful to study the effects of retail rates on both private and utility sides with the same amount of DERs installed in all particular facilities. To extend the analysis, the endogenous investment then revealed what course the investments made by the facilities could take since they would try to minimize their investment costs. Two scenarios using different DER costs were studied in this case: a conservative scenario and an optimistic one.

The exogenous analysis showed that the final electricity bill reduction was directly linked to the charge and discharge strategies, determining the demand reduction over different periods. We found that solar PVs reduced electricity bills significantly under the energy tariff TOU-ENE for all DER combinations compared to other tariffs.

Whereas, on the utility side, the tariffs with high demand charges often presented lower cost-shifting. This finding underlines the negative impact that a regulatory change aiming to reduce cost-shifting values for buildings already under energy tariff and high solar PV would have on their budget.

The endogenous investment model revealed how the facility would invest rationally to minimize its costs. For the conservative scenario, the average DER capacity installed often used EV+BESS to reduce its electricity costs, indicating that the mix can work together to support the facility grid, each one bringing its benefits. Coincident peak tariff was noteworthy for the results for conservative endogenous investments, in which we obtained the highest NPV and the lowest cost-shifting. The drawback of this kind of rate is that there is a danger of creating a demand peak elsewhere in the daytime, probably early morning (8–10 AM) or even later evening (9–11 PM). In the optimistic scenario, TOU-COIN is not as attractive as before for buildings due to the limited gains obtained after offsetting all coincident demand, so there is no more investment from this point. Nevertheless, only under TOU-CAP, the avoided costs increase more than electric savings by using cheap storage to target several hours of the day. The shift from energy-based tariffs toward coincidental and capacity-based tariffs can alleviate cost-shifting values caused by strong DER penetration.

The last aspect we analyzed is the EV net income obtained from energy services provided to the facility. Their availability and the tariff in which the buildings are under have an essential impact on their adoption by facilities, and consequently, on their revenues. Regarding EVs, the net income revenue varied between $57 and $218, with the highest revenue found under TOU-CAP. Although bill management can be the topmost remunerated service for EVs, it still strongly depends on the tariff and the contract to split gains between EV owners and the facilities. In addition, the optimistic scenario showed that batteries substituted almost all the available vehicles, capturing their share of the value created under all tariffs.

Our results could be used as a roadmap for other countries and regions seeking to invest in solar PV generation, stationary batteries, and electric vehicles.[35] They help weigh up tariff effects under several parameters of analysis. Minimizing total costs is the approach most often taken in the literature due to the attractiveness of the profits that DERs can bring, although multi-objective optimization taking into account $CO_2$ emission reduction is also well-represented. The electrification of other sectors (heating) can also be a part of a future analysis with the addition of other DERs such as heat pumps. For instance, they can provide extra flexibility to buildings if coupled properly in the DER mix.[36] Studies are needed using fairness functions between heterogeneous agents with and without installed DERs to minimize the inequalities created by the tariff applied. The tariff schemes used in this paper are existing rates, but more granular time-specific tariffs with more levels for time-of-use periods besides super off-peak periods or more location-specific tariffs components now warrant investigation.

## CRediT authorship contribution statement

**Icaro Silvestre Freitas Gomes:** Conceptualization, Methodology, Formal analysis, Investigation, Writing – original draft, Writing – review & editing. **Yannick Perez:** Methodology, Investigation, Writing – review & editing, Supervision, Funding acquisition. **Emilia Suomalainen:** Methodology, Investigation, Writing – review & editing, Supervision, Funding acquisition.

[35] The strongest barrier to apply the same methodology using a different region is the lack of public available Avoided Cost Model (ACM). The ACM used in this work was developed especially for the Californian electric system and made publicly available. Although many utilities of countries may have this kind of model for their systems, it is only for internal purpose utilization.

[36] The methodology allows the coupling of different types of DERs since the DER-CAM model has this option. A paper written by the DER-CAM team (Steen et al., 2015) explains how the modeling of heat pumps is done.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Acknowledgments

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## Appendix A. Optimization program

The endogenous model is fully described in this section with the main variables reflecting the charge and discharge decisions, solar, battery, and electric vehicle optimum capacity along with its constraints. The exogenous model is a simple modification of the fully endogenous one in which the DER capacities are fixed before leaving the choice of charge and discharge strategies to the model. For additional details, see Cardoso et al. (2017), Stadler et al. (2013), Momber et al. (2010).

- Indices and general notation:
  - EV: Electric vehicle;
  - ES: Stationary battery;
  - PV: Photovoltaic panel
  - m: Month index 1,2, 3...12;
  - h: Hour index 1, 2...24;
  - d: Day type 1,2,3;
  - k: All storage technologies (EV ∪ ES);
  - i: Set of all technologies (k ∪ PV);
  - s: Season winter, summer;
  - p: Tariff period on-peak, mid-peak, off-peak;
  - NonCoin: Non-coincidental hours of the day;
  - Coin: Coincidental hour of the day;
- Parameters
  - $load_{m,d,h}$: Client electricity demand in month m, day-type d and hour h [kW];
  - $ScArea_{PV}$: Area available for solar PV technology [$m^2$];
- Market data
  - $TEx_{m,d,h}$: Tariff for electricity export at time m,d,h [$/kWh];
  - $TF_m$: Fixed charges for electricity access for month m [$];
  - $TE_{m,d,h}$: Tariff for electricity consumption at time m,d,h [$/kWh];
  - $TP_{s,p}$: Demand charges for season s and period p [$/kW];
  - $TPNC_m$: Demand non-coincidental charges for m [$/kW];
  - $TPC_m$: Demand coincidental charges for m [$/kW];
  - $P_{EV}$: Electric vehicle electricity exchange price in residence [$/kWh];
  - $An_i$: Annualized capital cost of DER technology i [$];
  - $IR$: Interest rate on investments [%];

- $Lt_i$: Lifetime of technology i [years];
- $PBPeriod$: Payback period to integrate DER investments [years];
- $BAUCost$: Total energy cost in the business-as-usual case without investments in DER [$];

• Technology data

- $SCEff_k$: Charging efficiency of storage technology k [%];
- $SDEff_k$: Discharging efficiency of storage technology k [%];
- $SCRate_k$: Maximum charge rate of storage technology k [%];
- $SDCRate_k$: Maximum discharge rate of storage technology k [%];
- $GenU_{PV,m,d,h}$: Electricity generated to be used in the microgrid in time m,d,h [kW];
- $GenS_{PV,m,d,h}$: Electricity generated to be exported in time m,d,h [kW];
- $ScEff_{PV,m,h}$: Solar radiation conversion efficiency of PV technology in month m and hour h [%];
- $ScPeakEff_{PV}$: Peak solar conversion efficiency of PV technology [%];
- $SI_{m,d,h}$: Solar insulation at time m,d,h [kW/$m^2$];
- $EVCL$: Electric vehicle capacity loss per normalized Wh [dimensionless];
- $EVFRC$: Future replacement cost of electric vehicle batteries [$/kWh];
- $DEROMFix_i$: DER fixed annual operation and maintenance cost per year of technology i [$/kW or $/kWh];
- $CFixcost_i$: Fixed capital cost of technology i [$];
- $CVarcost_i$: Variable capital cost of technology i [$/kW or $/kWh];
- $\overline{SOC_k}$:Maximum state of charge for technology k [dimensionless];
- $\underline{SOC_k}$: Minimum state of charge for technology k [dimensionless];
- $\varphi_k$: Losses due to self-discharge for technology k [%];

• Decision variables

- $UL_{m,d,h}$: Client electricity purchased in month m, day type d and hour h [kW];
- $SIn_{k,m,d,h}$: Energy input to storage technology k at time m,d,h [kW];
- $SOut_{k,m,d,h}$: Energy output by storage technology k at time m,d,h [kW];
- $E^{r\to c}_{m,h}$: Electricity flow from the residential building to the car [kWh];
- $E^{c\to r}_{m,h}$: Electricity flow from the car to the residential building [kWh];
- $Cap_i$: Installed capacity technology i [kW for PV and kWh for technologies k];
- $Psb$: Binary decision of purchase or selling electricity in month m, day type d and hour h [dimensionless];
- $Pur_i$: Binary decision value of customer purchase of technology i [dimensionless];

**Objective function**:

$$Min\ c_{total} = c_{elec} + c_{DER} + c_{EV} - \sum_m \sum_d \sum_h GenS_{PV,m,d,h} \cdot TEx_{m,d,h} \quad (A.1)$$

**Where**:

$$c_{elec} = \sum_m TF_m + \sum_m \sum_d \sum_h UL_{m,d,h} \cdot TE_{m,d,h} + \sum_s \sum_{m \in s} \sum_p TP_{s,p} \cdot max(UL_{m,(d,h) \in p}) + \sum_m TPNC_m \cdot max(UL_{m,d,(h) \in NonCoin}) + \sum_m TPC_m \cdot UL_{m,d,(h) \in Coin} \quad (A.2)$$

$$c_{DER} = \sum_i (CFixcost_i \cdot Pur_i + CVarcost_i \cdot Cap_i) \cdot An_i + Cap_i \cdot DEROMFix_i \quad (A.3)$$

$$c_{EV} = \sum_m \sum_h P_{EV} \cdot \left( \frac{E^{r\to c}_{m,h}}{SCEff_{k=\{EV\}}} - E^{c\to r}_{m,h} \cdot SDEff_{k=\{EV\}} \right) + \sum_m \sum_h EVCL \cdot EVFRC \cdot (SIn_{k=\{EV\}} + SOut_{k=\{EV\}} + E^{r\to c}_{m,h} + E^{c\to r}_{m,h}) \quad (A.4)$$

**Main constraints**:

1. Energy balance

$$load_{m,d,h} + \sum_k \frac{SIn_{k,m,d,h}}{SCEff_k} = \sum_k SOut_{k,m,d,h} \cdot SDEff_k + GenU_{PV,m,d,h} + UL_{m,d,h}\ \forall\ m,d,h. \quad (A.5)$$

2. PV output constraint

$$GenU_{PV,m,d,h} + GenS_{PV,m,d,h} \leqslant \frac{Cap_i}{ScPeakEff_{PV}} \cdot ScEff_{PV,m,h} \cdot SI_{m,d,h}\ \forall\ m,d,h : i \in \{PV\} \quad (A.6)$$

$$\frac{Cap_{PV}}{ScPeakEff_{PV}} \leqslant ScArea_{PV} \quad (A.7)$$

3. Storage constraints

$$Cap_k \cdot \underline{SOC_k} \leqslant \sum_{n=0}^{h} (SIn_{k,m,d,n} - SOut_{k,m,d,n}) \cdot (1 - \varphi_k) \leqslant Cap_k \cdot \overline{SOC_k} \forall\ k,m,d,h. \quad (A.8)$$

$$SIn_{k,m,d,n} \leqslant Cap_k \cdot SCRate_k \forall\ k,m,d,h. \quad (A.9)$$

$$SOut_{k,m,d,n} \leqslant Cap_k \cdot SDCRate_k \forall\ k,m,d,h. \quad (A.10)$$

4. General constraints

$$UL_{m,d,h} \leqslant Psb_{m,d,h} \cdot M\ \forall\ m,d,h. \quad (A.11)$$

$$GenS_{PV,m,d,h} \leqslant (1 - Psb_{m,d,h}) \cdot M\ \forall\ m,d,h. \quad (A.12)$$

$$Cap_i \leqslant Pur_i \cdot M\ \forall\ i. \quad (A.13)$$

$$An_i = \frac{IR}{1 - \left(\frac{1}{(1+IR)^{Lt_i}}\right)} \forall\ i. \quad (A.14)$$

$$C \leqslant BAUCost + \sum_i (CFixcost_i \cdot Pur_i + CVarcost_i \cdot Cap_i) \cdot \left( An - \frac{1}{PBPeriod} \right) \quad (A.15)$$

## Appendix B. Exogenous investment DER sizing

There are several ways to size the installed solar PVs coupled with storage according to electricity needs, available space, and budget. For instance, it is possible to offset 100% of the electricity consumption and become independent of the grid. However, this method often leads to oversized solar PVs and battery storage, which is usually not financially attractive. Another option is to size the DERs to offset a

share of the non-coincidental or coincidental demand, reduce energy consumption during on-peak periods, and arbitrage electricity between different time windows or different places (commercial building and dwelling) via electric vehicle home charging. Here, we extend the method used Boampong and Brown (2020) to our buildings and the utilization of EVs. First, the portion of installed PV is expected to be large enough to offset 40% of the average annual week-day consumption; the power output required to meet 40% of the daily consumption is given by hourly adding the kWh needed along the day multiplied by the percentage offset factor.[37] This is then divided by the scaled full sun equivalent obtained via the Solar Irradiation Database for the Los Angeles suburban area from the National Solar Radiation Database. Finally, this value is divided by the NREL Watts' default derate factor of 0.77, which accounts for shade, dirt, and losses.[38]

The addition of storage can be useful to avoid excessive solar exports, reduce maximum demand, and arbitrage electricity throughout the hours of the day. To size BESSs, we simulate our average Solar PV generation to calculate the net load for each hour according to the facilities by subtracting the average annual week-day load of the facilities from the average Solar PV generation. The battery size is then the sum of the positive deviations of the net load from its mean during the most constrained hours of the system (4–9 PM) to flatten the peak load at this time. For the EV battery sizing, we use the equivalent capacity of the stationary battery calculated to find the trade-off between maximum charging/discharging power and available energy. Since the charging and discharging power rate and the maximum and minimum battery state of charge differ in these two DERs, we would have one scenario with the equivalent energy available and another with the equivalent power of the stationary batteries; a compromise is, therefore, necessary to avoid oversizing any of them.[39] The average solar PV amount for all facilities is 108.4 kWp, with a standard deviation of 54.89 kWp. In the case of batteries, the average is 147 kWh with 74.65 kWh of standard deviation, 278.4 kWh, and 125 kWh for EV average and standard deviation, respectively. Finally, after the amounts of DERs are calculated, we formulate three different technology scenarios: PV+BESS, PV+EV, and PV+EV+BESS[40] under three different tariff structures (TOU-CAP, TOU-COIN, TOU-ENE) to proceed with our analysis.

## Appendix C. Charging and discharging strategies

In this section, the storage charging and discharging episodes are discussed in depth according to the DER combination under the adopted tariffs. First, Fig. C.8(a) show the charging behavior with only batteries while Fig. C.8(b) shows the situation when vehicles are present. Then, Figs. C.8(c) and C.8(d) show the charging behavior for the combination of both of them (EV+BESS).

For the BESS scenario described in Fig. C.8(a), under the capacity tariff (TOU-CAP), the battery is charged within the time period from 6 AM to 3 PM, but the main charging episode starts at 11 AM, lasting until 4 PM just before the beginning of the on-peak period. Under energy tariff (TOU-ENE), the charging strategies show very similar behavior to the capacity tariff to avoid the same on-peak periods. For the coincident peak tariffs, the battery is charged from 6 AM, with the main event starting at 1 PM and lasting until 4 PM, so that the battery can be charged enough when the coincident peak maximum demand charge (MDC) comes into effect.

Most of the EV charging is done at owners' homes during off-peak hours with a specific tariff. However, according to Fig. C.8(b), a charging episode occurs when they arrive at 9 AM and lasts until 3 PM for all the tariffs when there is PV electricity excess with a peak around 12 PM to avoid profitless exports. For the coincident peak tariffs, the charging occurs from 9 AM until 4 PM, adding more energy on top of home charging. When the two forms of storage are present concomitantly (Figs. C.8(c) and C.8(d)), the BESS charging is prioritized over EVs, while EVs are charged only when there is excess PV electricity generated from 10 AM until 3 PM for all tariffs. The charging pattern of the total charge, EV+BESS charging, is closely related to that with the BESS alone, which can be interpreted as an optimum strategy to follow. Finally, under coincident peak tariffs, the same behavior is found as under the other tariffs for the mix.

With regard to discharging strategies, there are several incentives to adopt storage, such as energy arbitrage, offset coincident peak MDC, non-coincidental MDC, and on-peak MDC. These are all summarized in Table C.10 along with the time at which each one occurs for each tariff. Since the PV generation is adequately synchronized with the load of the facilities, it reduces a fair amount of maximum private demand, between 15% to 34% outside winter periods when the generation drops. The storage discharge strategy then focuses on offsetting the high demand periods outside the PV coverage when the fall in electricity production needs to be compensated for, which is from 4 PM. For all DER combinations, under coincident peak tariffs, the discharge occurs between 3 PM and 7 PM with different power peak rates.

Under the capacity tariff, the BESS starts discharging primarily to avoid its private peak demand, which is around 4–5 PM, and tries to offset the on-peak demand as much as possible until 9 PM. Under the energy-based tariff, the BESS discharge is employed to arbitrage energy between off-peak periods to on-peak. It supplies electricity from 3 PM until 9 PM with a peak at around 5 PM to offset the on-peak demand concomitantly. We note that the highest amount of energy discharge occurs, except for coincident peak tariffs, at 5 PM, as shown in Figs. C.9(a) and C.9(b) when the load is still high, and the PV production is almost at its minimum level.

For EVs, under the capacity tariff, the EV starts discharging to primarily avoid the facility private peak demand, which is at 4–5 PM. EVs do not discharge at maximum power to offset the private peak because the battery degradation for EVs would offset the gains from private peak demand reduction. In addition, it is more useful to charge the vehicle with PV surplus to collect the narrow spread between the electricity generated at the building and that used to charge it at the owners' homes during summertime. Under the energy-based tariff, EVs discharge to arbitrage energy between off-peak and on-peak inside the facility and with the electricity consumed at their homes. This follows the strategy adopted by the BESS, but it has its constraints. EVs supply electricity from 3 PM to 7 PM; when the EVs depart, a higher discharge peak power rate managed by the charging station tries to compensate for the departure, proving that the EV discharging strategy is intimately connected to the arrival and departure schedules. There is no discharging episode starting around 7 AM simply because they are not yet connected at this time (Figs. C.9(b)–C.9(d)).

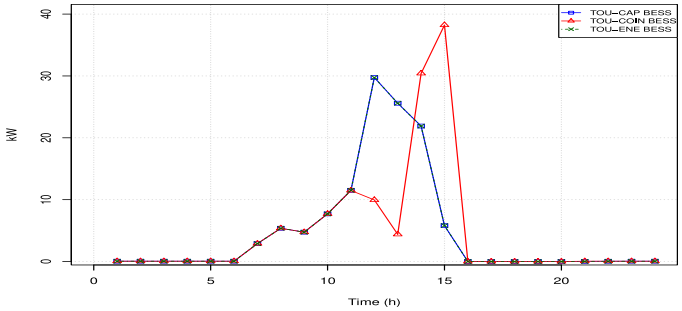
For the joint combination of EV+BESS (Figs. C.9(c) and C.9(d)), under the capacity tariff, it tries to replicate the same discharge strategy as in the scenario with only BESS. However, with battery support, EVs discharge nearly at their maximum average power rate (18 kW), compensating for the degradation and still trying to offset as much as

[37] The percentage offset factor states how much of the average annual week-day consumption will be offset by PV production. In our exogenous investment scenario, we choose 40% to avoid excessive solar exports to the grid. This factor was proved in the method not to strongly influence the qualitative results in the following sections.

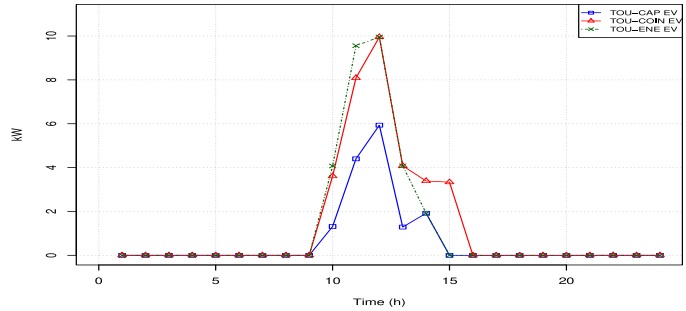
[38] We calculate the output power for the medium office PV in the following manner: The sum of the hourly average week-day consumption is 2,063 kWh. By applying the factor of 40% we have a final value of 825 kWh; we divide this by the full sun equivalent for the region, which is 5.2h, and the NREL Watts factor 0.77, giving a final result of 206 kWp. The general formulation is given by: $PV_{out} = \frac{Average\ annual\ week-day\ consumption \cdot \%\ Offset factor}{Full\ sun\ equivalent \cdot NREL\ Watts\ Factor}$.

[39] For example, a stationary battery of 258 kWh was sized for the medium office. To have the same energy available, 6 EVs are needed. To maintain the equivalent power discharge rate, 10 EVs are required with the adopted parameters. In this case, the middle value of 8 vehicles is therefore chosen.

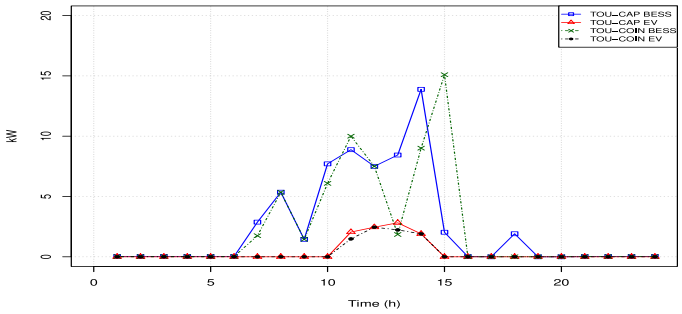
[40] The values of EV and BESS are halved in the last scenario to keep the amount of storage close to the other storage scenarios (e.g., PV+BESS and PV+EV).



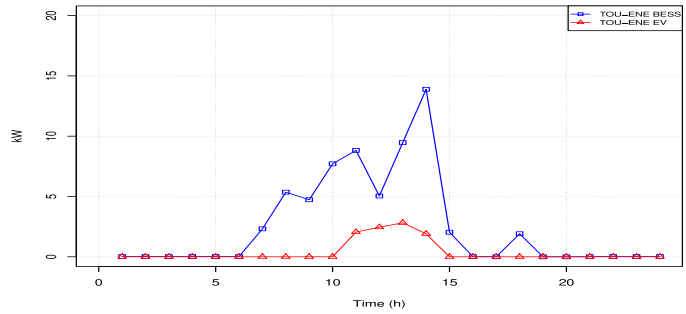

(a) BESS charging strategies under all tariffs.




(b) EV charging strategies under all tariffs.

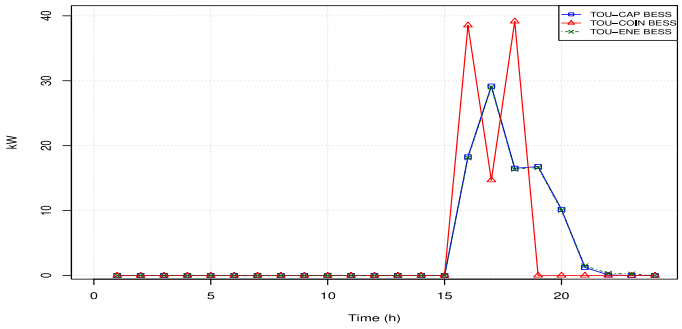



(c) EV+BESS charging strategies under TOU-CAP and TOU-ENE.

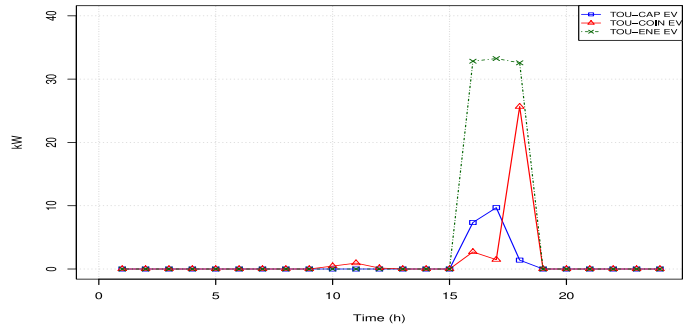



(d) EV+BESS charging strategies under TOU-COIN.

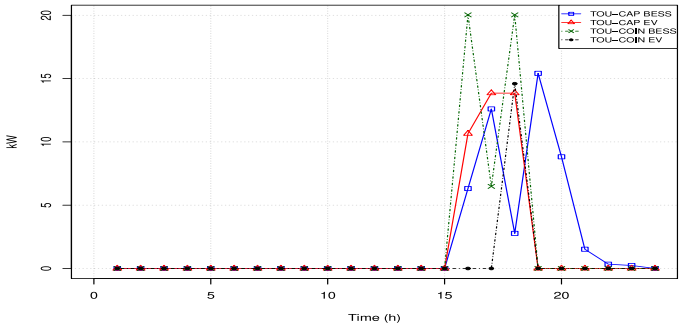
**Fig. C.8.** Charging strategies according to different DER scenarios and tariffs during summer (September).



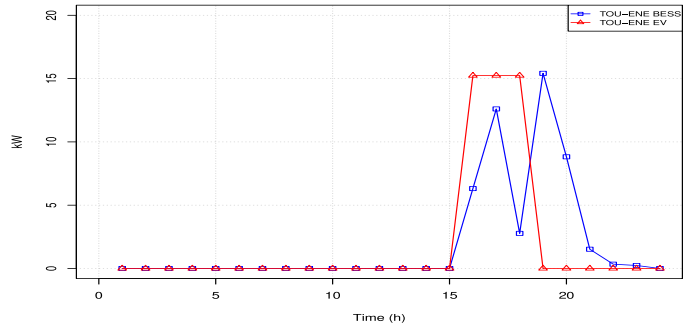

(a) BESS discharging strategies under all tariffs.




(b) EV discharging strategies under all tariffs.




(c) EV+BESS discharging strategies under TOU-CAP and TOU-ENE.




(d) EV+BESS discharging strategies under TOU-COIN.

**Fig. C.9.** Discharging strategies according to different DER scenarios and tariffs during summer (September).

**Table C.10**
Discharging incentives per tariff structure.

| Tariff | Coin peak MDC | Non-coin MDC | On-peak MDC | Energy arbitrage |
|---|---|---|---|---|
| TOU-CAP | – | BESS: 3–8 PM (5 PM)[a]<br>EV: 3–7 PM (5 PM)<br>BESS/EV: 3–8 PM (7 PM)<br>/3–7 PM (6 PM) | BESS: 4–9 PM<br>EV: 3–6 PM<br>BESS/EV: 4 -<br>9 PM/4–7 PM | – |
| TOU-Coin | 5–7 PM (6 PM) | – | – | – |
| TOU-ENE | – | BESS: 3–8 PM<br>EV: 3–7 PM<br>BESS/EV: 3–10 PM<br>/3–7 PM | BESS: 4–9 PM<br>EV: 3–7 PM<br>BESS/EV: 4–9 PM<br>/ 4–7 PM | BESS: 4–9 PM (5 PM)<br>EV: 4–7 PM (5 PM)<br>BESS/EV: 4–9 PM (7 PM)<br>/ 4–7 PM (4 PM) |

[a]The values in parentheses are the hour when the highest amount of discharging occurs.

possible the on-peak demand until 9 PM. Under the energy-based tariff, EVs are the primary discharging storage form before their departure, while the BESS is just supporting them. When EVs start to leave, the BESS becomes the only storage system trying to arbitrage as much energy as possible during on-peak times.[41]

## Appendix D. Complementary tables

**Table D.11**
SCE's General Services 2 electricity retail tariffs.

| | TOU-CAP | TOU-COIN | TOU-ENE |
|---|---|---|---|
| Energy Charge ($/kWh) | | | |
| Summer on-peak | 0.11963 | 0.11963 | 0.48887 |
| Summer mid-peak | 0.11016 | 0.11016 | 0.16322 |
| Summer off-peak | 0.08055 | 0.08055 | 0.11227 |
| Winter mid-peak | 0.09781 | 0.09781 | 0.15888 |
| Winter off-peak | 0.0862 | 0.0862 | 0.08962 |
| Winter super off-peak | 0.06441 | 0.06441 | 0.07599 |
| Non coincidental demand charges ($/kW) | 10.35 | 0 | 7.49 |
| Coincidental demand charges ($/kW) | 0 | 14.37 (Winter)<br>30.20 (Summer) | 0 |
| Time-specific demand charges ($/kW) | | | |
| Summer on-peak | 19.85 | 0 | 4.35 |
| Summer mid-peak | 0 | 0 | 0 |
| Winter mid-peak | 4.02 | 0 | 0.85 |
| Monthly fixed charges ($/month)[a] | 129.9 | 129.9 | 129.9 |

[a]Fixed charges are the sum of customer, single phase service and TOU option meter charges.

**Table D.12**
SCE's General Services 2 electricity retail tariffs time schedule.

| | |
|---|---|
| Summer months (June 1st–September 30th): | |
| Summer on-peak | Weekdays: 4 PM–9 PM |
| Summer mid-peak | Weekends: 4 PM–9 PM |
| Summer off-peak | Weekdays and weekends: All hours except 4 PM to 9 PM |
| Winter months (October 1st–May 31st): | |
| Winter on-peak | |
| Winter mid-peak | Weekdays and weekends: 4 PM to 9 PM |
| Winter off-peak | Weekdays and weekends: 9 PM to 8 AM |
| Winter super off-peak | Weekdays and weekends: 8 AM to 4 PM |

[41] In some hours, charging and discharging may coincide in the graphs, but this does not mean that the BESS or EV are charging and discharging at the same time; the model prevents this from happening. Because we use an average profile of the building strategies, some individual patterns may be hidden, but the objective is to find the primary behavior.

**Table D.13**
Variable coincidental hours along the months.

| Month | Hour |
|---|---|
| January | 7:00 PM |
| February | 7:00 PM |
| March | 7:00 PM |
| April | 7:00 PM |
| May | 7:00 PM |
| June | 7:00 PM |
| July | 6:00 PM |
| August | 6:00 PM |
| September | 6:00 PM |
| October | 5:00 PM |
| November | 6:00 PM |
| December | 6:00 PM |

**Table D.14**
Average % change in demand during system peak times for PV+BESS and PV+EV.

| | PV+BESS | | | PV+EV | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| January | −30.8 | −35.9 | −33.7 | −9.0 | −2.0 | −8.1 |
| February | −34.0 | −42.4 | −37.3 | −11.5 | −5.2 | −9.9 |
| March | −37.8 | −51.0 | −42.7 | −14.9 | −11.0 | −14.9 |
| April | −34.9 | −59.9 | −56.2 | −20.0 | −19.7 | −20.0 |
| May | −58.3 | −70.5 | −63.3 | −23.6 | −23.3 | −23.6 |
| June | −57.4 | −70.6 | −65.9 | −27.4 | −27.0 | −58.5 |
| July | −43.9 | −43.0 | −43.6 | −12.6 | −29.5 | −46.7 |
| August | −42.7 | −41.7 | −42.5 | −10.6 | −28.6 | −45.5 |
| September | −38.3 | −37.0 | −38.0 | −7.8 | −25.8 | −42.9 |
| October | −32.5 | −29.7 | −32.6 | −4.8 | −19.0 | −4.8 |
| November | −26.8 | −25.1 | −27.9 | −10.0 | −16.6 | −10.0 |
| December | −27.3 | −27.2 | −30.1 | −9.4 | −17.5 | −9.4 |

**Table D.15**
Average % change in maximum private demand for PV+BESS and PV+EV.

| | PV+BESS | | | PV+EV | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| January | −39.6 | 9.7 | −36.8 | −16.6 | −2.7 | −16.6 |
| February | −42.7 | −5.4 | −39.6 | −18.7 | −4.8 | −18.7 |
| March | −49.4 | −16.8 | −45.5 | −24.0 | −15.0 | −24.0 |
| April | −64.8 | −35.9 | −61.2 | −36.6 | −35.5 | −36.6 |
| May | −63.2 | −35.7 | −60.1 | −34.9 | −30.6 | −34.9 |
| June | −59.1 | −37.5 | −55.2 | −38.4 | −34.6 | −38.4 |
| July | −46.8 | −14.7 | −47.1 | −33.2 | −20.2 | −33.2 |
| August | −45.1 | −12.9 | −45.0 | −29.4 | −19.1 | −29.4 |
| September | −43.4 | −9.9 | −43.8 | −27.8 | −16.6 | −27.8 |
| October | −44.7 | 11.2 | −44.7 | −25.9 | −16.4 | −25.9 |
| November | −35.7 | 19.6 | −34.5 | −21.4 | −6.7 | −21.4 |
| December | −34.9 | 28.8 | −31.7 | −19.3 | −4.9 | −19.3 |

**Table D.16**
Average % change in demand for PV+EV+BESS.

| | System peak demand | | | Private peak demand | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| January | −25.0 | −17.8 | −25.7 | −33.7 | −3.6 | −32.3 |
| February | −28.8 | −22.3 | −30.0 | −38.2 | −6.4 | −36.5 |
| March | −31.0 | −28.4 | −33.3 | −43.7 | −18.0 | −41.8 |
| April | −40.6 | −37.6 | −47.2 | −57.9 | −39.1 | −56.6 |
| May | −44.9 | −44.1 | −49.1 | −56.9 | −34.1 | −56.2 |
| June | −49.8 | −49.7 | −60.7 | −55.7 | −37.5 | −52.8 |
| July | −37.5 | −34.2 | −45.5 | −46.8 | −27.0 | −46.7 |
| August | −36.2 | −32.6 | −43.3 | −44.3 | −25.1 | −43.8 |
| September | −32.3 | −29.8 | −38.7 | −43.1 | −22.2 | −43.1 |
| October | −28.1 | −23.6 | −28.4 | −43.4 | −18.0 | −43.6 |
| November | −25.8 | −20.1 | −25.1 | −35.2 | −7.3 | −34.6 |
| December | −21.6 | −21.1 | −23.1 | −30.2 | −4.9 | −29.2 |

**Table D.17**
Total building electric costs per technology scenario.

| Total building electric costs ($) | | | |
|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE |
| Basecase | 50,144 | 43,729 | 57,517 |
| (St. Dev.) | (23,538) | (20,931) | (27,012) |
| PV+BESS | 24,640 | 18,557 | 27,774 |
| (St. Dev.) | (10,359) | (8,659) | (12,432) |
| PV+EV | 31,104 | 25,882 | 33,079 |
| (St. Dev.) | (13,110) | (12,470) | (14,742) |
| PV+EV+BESS | 26,304 | 22,243 | 29,620 |
| (St. Dev.) | (10,881) | (10,467) | (13,093) |

**Table D.18**
Average avoided costs — Case 2. ($)

| | TOU-CAP | TOU-COIN | TOU-ENE |
|---|---|---|---|
| Avoided costs of solar PV+BESS — Case 2. | | | |
| Total mean | 17,501 | 17,589 | 17,201 |
| (St. Dev.) | (8,503) | (8,431) | (8,400) |
| Energy | 9,042 | 8,644 | 8,767 |
| (St. Dev.) | (4,447) | (4,348) | (4,332) |
| Capacity | 8,459 | 8,684 | 8,434 |
| (St. Dev.) | (4,090) | (4,177) | (4,108) |
| Avoided costs of solar PV+EV — Case 2 | | | |
| Total mean | 10,521 | 12,770 | 15,051 |
| (St. Dev.) | (6,057) | (6,150) | (7,669) |
| Energy | 6,596 | 6,811 | 7,332 |
| (St. Dev.) | (3,480) | (3,344) | (3,741) |
| Capacity | 3,926 | 5,959 | 7,719 |
| (St. Dev.) | (2,584) | (2,856) | (3,968) |
| Avoided costs of solar PV+EV+BESS — Case 2 | | | |
| Total mean | 15,290 | 15,142 | 16,327 |
| (St. Dev.) | (8,114) | (7,553) | (8,471) |
| Energy | 8,132 | 7,740 | 8,370 |
| (St. Dev.) | (4,198) | (3,952) | (4,272) |
| Capacity | 7,157 | 7,402 | 7,957 |
| (St. Dev.) | (3,932) | (3,659) | (4,209) |

**Table D.19**
Average cost-shifting measures by technologies and tariffs — Case 2. ($)

| | TOU-CAP | TOU-COIN | TOU-ENE |
|---|---|---|---|
| PV+BESS | 8,095 | 7,829 | 12,668 |
| (St. Dev.) | (5,312) | (4,141) | (6,329) |
| % of savings | 31.7 | 31.1 | 42.6 |
| PV+EV | 8,519 | 5,077 | 9,386 |
| (St. Dev.) | (5,150) | (2,390) | (5,045) |
| % of savings | 44.7 | 28.4 | 38.4 |
| PV+EV+BESS | 8,550 | 6,345 | 11,569 |
| (St. Dev.) | (5,174) | (3,058) | (5,657) |
| % of savings | 35.9 | 29.5 | 41.5 |

**Table D.20**
Average DER installed capacity — TOU-COIN Endogenous case.

| | Conservative scenario | | Optimistic scenario | |
|---|---|---|---|---|
| | 5–8 PM | 6 PM | 5–8 PM | 6 PM |
| PV (kW) | 0.0 | 0.0 | 83.8 | 84.0 |
| (St. Dev.) | (0.0) | (0.0) | (38.2) | (37.7) |
| #> 0[a] | 0.0 | 0.0 | 5.0 | 5.0 |
| BESS (kWh) | 183.2 | 2.2 | 258.8 | 261.0 |
| (St. Dev.) | (103.6) | (–) | (152.4) | (149.2) |
| #> 0 | 5.0 | 1.0 | 5.0 | 5.0 |
| EV (kWh) | 72.3 | 475.4 | 0.0 | 0.0 |
| (St. Dev.) | (29.2) | (269.8) | (0.0) | (0.0) |
| #> 0 | 4.0 | 5.0 | 0.0 | 0.0 |

[a] #> 0 values count the facilities with positive DER capacity installed.

**Table D.21**
Average avoided costs and cost-shifting — Endogenous case 2. ($)

| | Conservative scenario | | | Optimistic scenario | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| Avoided costs — Endogenous case 2 | | | | | | |
| Total mean | 6,932 | 9,625 | 22,189 | 27,879 | 16,506 | 28,446 |
| (St. Dev.) | (4,510) | (5,577) | (9,931) | (22,632) | (13,581) | (23,219) |
| Energy | 2,672 | 2,581 | 8,658 | 15,598 | 9,310 | 16,132 |
| (St. Dev.) | (1,753) | (1,578) | (3,491) | (7,508) | (4,403) | (7,882) |
| Capacity | 4,260 | 7,043 | 13,531 | 18,318 | 11,123 | 18,275 |
| (St. Dev.) | (2,805) | (4,006) | (7,039) | (9,065) | (5,577) | (9,266) |
| Cost-shifting — Endogenous case 2 | | | | | | |
| | Conservative scenario | | | Optimistic scenario | | |
| Total mean | 5,658 | 3,217 | 7,642 | 9,245 | 10,296 | 16,897 |
| (St. Dev.) | (3,918) | (2,054) | (2,023) | (13,018) | (9,641) | (13,132) |
| % from savings | 44.9 | 25.1 | 25.6 | 24.9 | 38.4 | 37.3 |

**Table D.22**
EV financial flow breakdown — Endogenous case. ($)

| | Conservative scenario | | | Optimistic scenario | | |
|---|---|---|---|---|---|---|
| | TOU-CAP | TOU-COIN | TOU-ENE | TOU-CAP | TOU-COIN | TOU-ENE |
| Home charging energy | 205.7 | 72.1 | 334.9 | 133.4 | 0.0 | 0.0 |
| (St. Dev.) | (22.4) | (37.1) | (16.5) | (71.6) | (0.0) | (0.0) |
| Battery Degradation | 111.3 | 20.5 | 194.6 | 83.1 | 0.0 | 0.0 |
| (St. Dev.) | (14.5) | (9.8) | (10.8) | (24.3) | (0.0) | (0.0) |
| Energy service | 436.4 | 303.5 | 114.5 | 51.7 | 0.0 | 0.0 |
| (St. Dev.) | (129.2) | (232.3) | (46.6) | (18.9) | (0.0) | (0.0) |
| Total Mean | 753.4 | 396.2 | 644.0 | 198.3 | 0.0 | 0.0 |
| (St. Dev.) | (128.1) | (273.9) | (73.8) | (7.6) | (0.0) | (0.0) |
| #> 0[a] | 3.0 | 4.0 | 3.0 | 3.0 | 0.0 | 0.0 |

[a] #> 0 values count the facilities with EVs.

**Table D.23**
Average EV financial flow breakdown — TOU-COIN Endogenous case. ($)

| | Conservative scenario | | Optimistic scenario | |
|---|---|---|---|---|
| | 5–8 PM | 6 PM | 5–8 PM | 6 PM |
| Home charging energy | 72.1 | 229.1 | 0.0 | 0.0 |
| (St. Dev.) | (37.1) | (23.7) | (0.0) | (0.0) |
| Battery Degradation | 20.5 | 126.7 | 0.0 | 0.0 |
| (St. Dev.) | (9.8) | (15.3) | (0.0) | (0.0) |
| Energy service | 303.5 | 852.0 | 0.0 | 0.0 |
| (St. Dev.) | (232.3) | (221.1) | (0.0) | (0.0) |
| Total Mean | 396.2 | 1,207 | 0.0 | 0.0 |
| (St. Dev.) | (273.9) | (250.1) | (0.0) | (0.0) |
| #> 0[a] | 4.0 | 5.0 | 0.0 | 0.0 |

[a] #> 0 values count the facilities with EVs.

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