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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 commercial private facilities studied do not own the vehicles and the vehicle owners receive compensation for energy services provided, which strongly depends on the type of tariff applied. We found that energy-based tariffs with on-peak periods synchronized with solar PV production brought the highest private gains, but with high cost-shifting. On the other hand, the capacity-based tariffs reduced the economic benefits and cost-shifting concomitantly, mainly when on-peak periods defined by the rate matched the most constrained grid time window. Batteries are incentivized mostly to offset maximum demand charges rather than to arbitrage energy, but this will strongly depend on the spread between on-peak and off-peak periods. Coincident peak rates, coupled with EVs, can bring high remuneration for EV owners, second-highest net present value, and second-lowest cost-shifting among all rates. Finally, we derive policy implications from the results and earmark more sophisticated tariff designs for investigation.

Highlights

- We analyse the interactions between retail tariff design and solar PVs*, stationary batteries and electric vehicles.
- Tariff design has a strong influence on battery and EV charging and discharging strategies.
- Energy-based tariffs lead to high PV investment, high financial returns and high cost-shifting, mainly when BESSs are present.
- Capacity-based tariffs with a high weighting in demand charges reduce cost-shifting and private remuneration under all DER combinations.
- Coincident peak tariffs coupled with EVs can bring high private gains, low cost-shifting and moderate EV remuneration.

Keywords

Electric vehicle, stationary battery, photovoltaic energy, tariff design

JEL classification: L51, L94, L97, Q42, Q48, Q55

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 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 ℃(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 and they are predicted to achieve around 1,000 $/kW by 2025 (Fu et al., 2018). At the same time, the costs of lithium-ion battery packs also fell threefold from 2007 to 2014, down to 300$/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). 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 5.1 million in 2018, up by 2 million since 2017 and 3.1 million since 2016 (IEA, 2019). However, EVs can be more than a mere transportation mode and can be considered as a distributed energy resource (DER) if smart-charging and vehicle-to-grid capabilities are enabled, for example.

All these changes in the electricity scenario directly affect how utilities charge their costumers a fair and cost-reflecting tariff. The rate structure is divided into energy charges [1], network charges (transmission and distribution)[2] and taxes and levies[3]. Of these three tariff parts, the one including the distribution network has been the subject of growing debates among national regulation authorities and academic experts over the last few years (Brown and Sappington, 2018, Pollitt, 2018, Brown and Faruqui, 2014). The discussions are mostly 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 tariffs), and locational granularity (uniform or distribution locational marginal pricing). 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

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

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CRediT authorship contribution statement

Icaro Silvestre Freitas Gomes: Conceptualization, Methodology, Formal analysis, Investigation, Writing - Original Draft. **Yannick Perez**: Methodology, Investigation, Supervision, Funding acquisition. **Emilia Suomalainen**: Methodology, Investigation, Supervision, Funding acquisition.

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

2 The network part reflects the costs of transmitting and distributing the electricity from the generation sites to endcustomers. It should include the costs inflicted on the network by the user's load profiles.

3 Finally, the taxes and levies applied are decided by the national governments.

network tariff design. 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 more efficient rate design will be needed[4].

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 (2019). 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. We find that energy tariffs increase private economic gains, whereas capacity tariffs reduce cost-shifting under all combinations of DERs for the commercial building load profiles close to a bell curve like PV production. Looking specifically at EV remuneration, we show that this varies annually from $380 to $1208 per vehicle, reaching the highest values when coincident peak 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, 2019). 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. The last section comprises the conclusion and policy implications.

2. Literature review

In this section, we analyze three main domains 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.

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

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

reduce costs by up to 18%. Moreover, lowcost 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 economic regulations, such as obsolete tariffs and ancillary service market designs that 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 cost-allocation and cross-subsidy issues, mainly when high shares of solar PVs are installed (Simshauser, 2016, Schittekatte et al., 2018, Sioshansi, 2016). 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. Network cost recovery using energy-based rates appears to be a larger distortion than the recovery of energy costs via time invariant rates according to Burger et al. (2020). 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. 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[5]. Another problem with this type of rate is that it can (over)incentivize storage adoption and create similar efficiency and fairness issues 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 (Kufeolu and Pollitt, 2019, Hoarau and Perez, 2019). Kufeolu 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[6]. 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.

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5 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.

6 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.

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[7]. 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 (2019) 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. Methods and Parameters

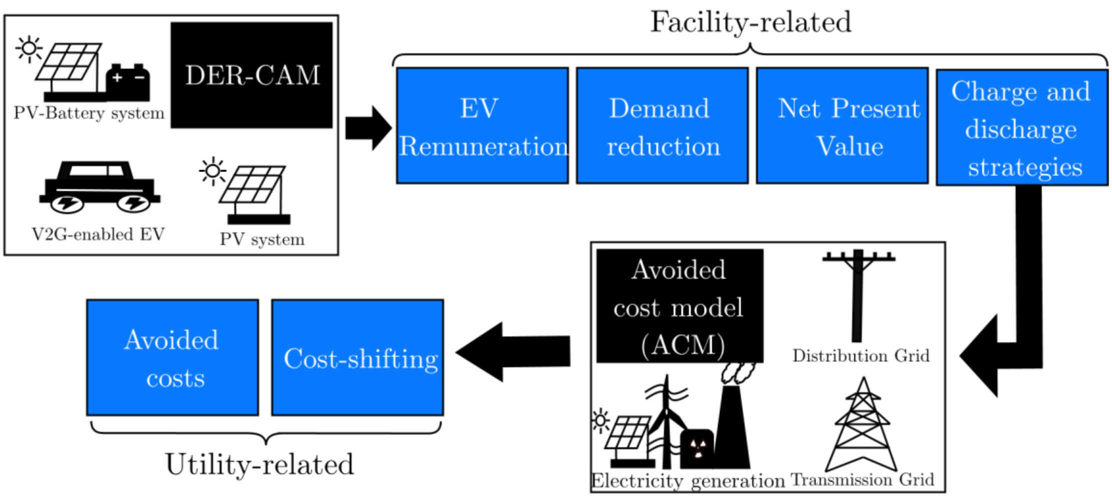
This section describes the model used to pursue the main goals of this research and present the data used as parameters to feed the model.

3.1 Method

The method used to obtain the results is based on that used in Boampong and Brown (2019), 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.

[7] 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.

Figure 1: Methodological framework



Two different types of investments are considered in this study: exogenous and endogenous. For the exogenous part, we consider four possible DER combination (PVs, 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 towards 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.

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. The adapted total cost function is divided into electricity costs, DER costs, EV costs, and export revenues:

$$Min\ c_{total} = c_{elec} + c_{DER} + c_{EV} - XExportsRev \qquad (1)$$

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 each kind of energy resource installed by the private facility. 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[8]. 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[9] Although the discharge can bring the highest gains, in the case of PV generation excess the charging can also become

8 The full equations and constraint formulations are presented in the appendix based on Cardoso et al. (2017), Stadler et al. (2013), Momber et al. (2010).

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

profitable since the model allows the EV owner to pay the facility back if the net energy value becomes negative (see equation A.4), that is, if the charging events outweigh the discharging events in the facility's grid. 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 requires it to meet several essential 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 help improve the objective solution, as stated in eqs. (A.11) to (A.13). 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 measurements when coupled with private economic savings from DERCAM. 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[10], 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[11]. Cap and Trade costs give the marginal cost of $CO2$ 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[12]. 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 value across the month. For the peak day, the maximum observed load during one day is

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10 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).

11 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.

12 20 years will be the period taken to calculate the net present value of the investment, which coincides with Solar PV lifetime.

filtered and used as the peak-day profile[13]. 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 week days and 0.8906 for weekends are obtained.

Figure 2: Marginal peak avoided costs profile for Forecasting Climate Zone 9 in 2020

Hour

Month	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	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	16,564.56	22,171.92	22,822.83	5,784.20	1,705.36	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	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 shows the breakdown of peak avoided costs for Climate Zone 9 per 12 months and 24 hours 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

13 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 (LBL, 2019).

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.

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 shows that the value of storage (stationary batteries and electric vehicles) is strongly dependent on the period, season, and charge and discharge strategies.

3.2 Parameters

The next section present and justify 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 take into account and the techno-economic characteristics of the resources. The load profile of commercial sites will be used for several reasons: DERs can play an important role in electricity consumption reduction in the buildings sector, as around half of the global electricity demand today is in this sector[14]; Secondly, the load profile peak is synchronized with the PV production during the day, which can lead 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)[15], 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 or without coincident demand chargers, make a reliable scenario to analyze the sensitivity of many parameters due to tariffs. Fig. 4 shows six different commercial and industrial (C&I) tariffs based on the rates proposed by South 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 includes 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 periods during winter. Lastly, the rates are uniformly adopted under SCEs territorial service zones[16]. We will use six tariff structures in total: two energy-based tariffs (TOUR and TOUE), two capacity-based tariffs (TOUB and TOUD), and two coincident peak demand tariffs (TOUE Coin and TOUD Coin) in which all demand charges are shifted

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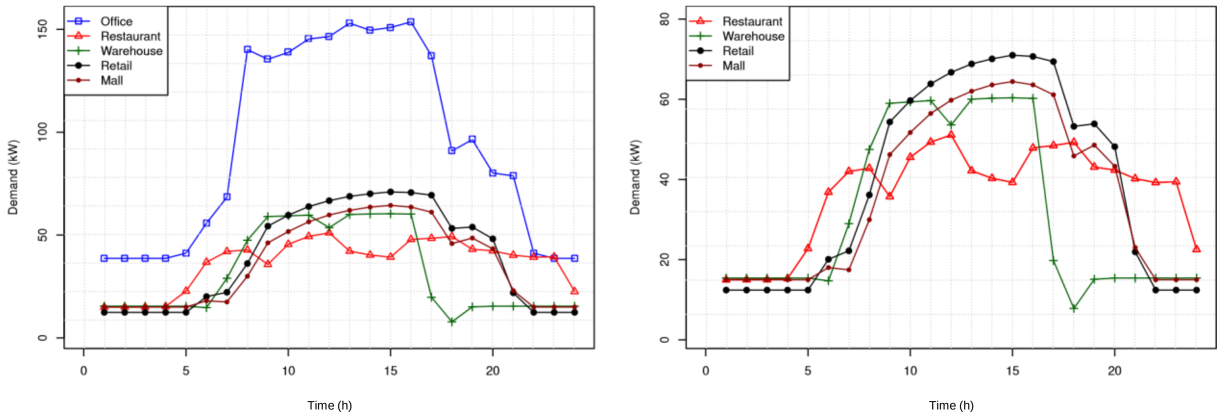
[14] It has also accounted for 52% of global electricity demand growth since 2000, contributing nearly 55% (7,200 TWh) to global growth through 2040 (IEA, 2018).

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

[16] The detailed rate values during summer and winter periods are presented in Tables A.13 and A.14.

towards a specific hour, in our case, 6 PM is the coincident hour due to the highest grid constraints observed then. SCE proposed the new tariffs

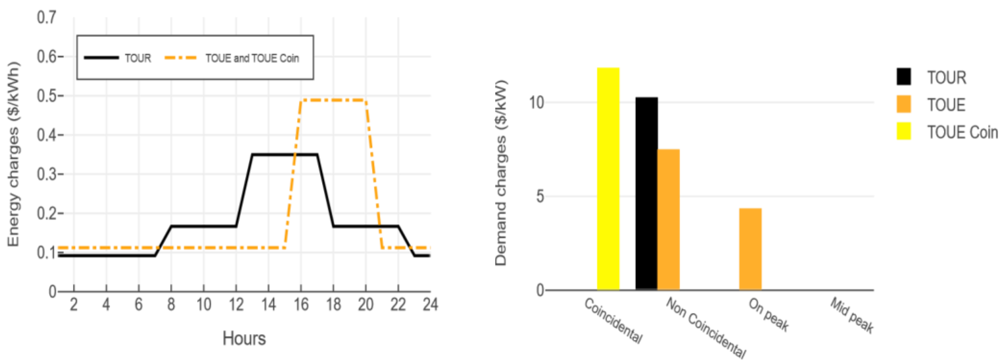
Figure 3: Commercial building load profiles



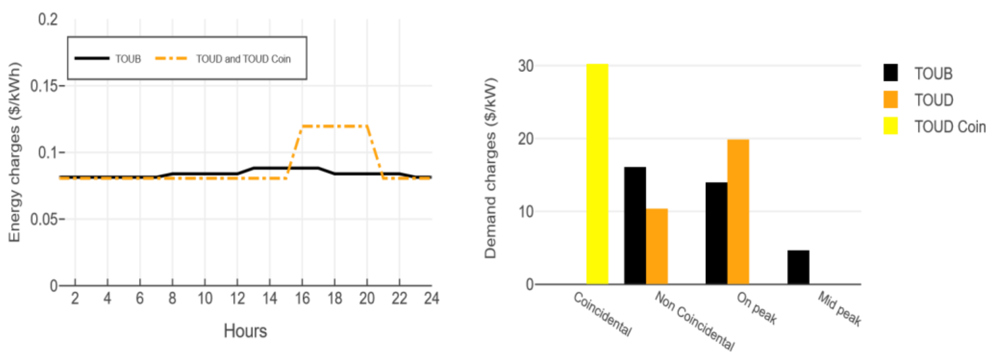
(a) Building Load Profiles (b) Smaller Building Load Profiles

TOUD and TOUE to better frame the grid constrained period by shifting the attributed on-peak period from around midday toward early evening.

Figure 4: Electricity tariff formats



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



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

Besides the rates applied to the private facility, the rates applied to EV owners during home charging are essential to justify 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 the middle value from a list of options after extensive benchmarking.

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). Variable costs found in the literature range from 1,250 to 3,237 \$/kW[17] (Beck et al., 2017, Hanna et al., 2017, Cardoso et al., 2017, Fu et al., 2017, Tervo et al., 2018, Koskela et al., 2019). Like for the variable cost parameter, which depends on the size of DER installed in kW for solar PV and kWh for battery energy storage systems (BESS) and EVs, there is a wide range of values for their lifetime, from 20 to 30 years. Finally, according to the middle-value method, the following specifications were selected: 2,100 \$/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.

Besides the market parameters, 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 variable costs, 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, Doroudchi et al., 2018, Fu et al., 2018, Koskela et al., 2019, IRENA, 2017). 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 variable cost into 215 \$/kWh. 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 variable cost value. Second, several technical parameters must also be defined. We thus set a charging and discharging efficiency of 90% (TeslaPowerwall, 2020), a maximum charging and discharging rate of 30%, and a state of charge between 20% and 100% 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 3,850 \$/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 1,900 \$/Station. To calculate the variable cost as an input to the model (\$/kWh), it is necessary to define an average battery capacity according to the Californian scenario of the vehicle 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 which results in a variable cost of accessing the EV battery of 32.75 \$/kWh, dividing the cost of installing a charging station per the average battery capacity.

[17] 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.

A lifetime of 10 years and fixed operation and maintenance costs of 0.28 $/kWh per month (10% of the variable cost per year) were also taken. Table 1 summarizes all the costs taken for the different DERs.

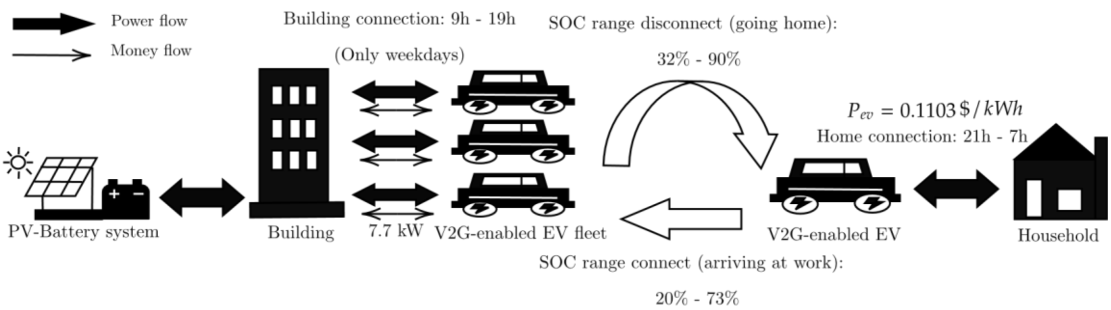
Table 1: Adopted DER costs

	Solar PV	Battery	Electric Vehicles
Fixed cost	-	$500	7 kW V2G DC Charging Station: 3850 $/station
Variable cost	2100 $/kWac	465 $/kWh	-
Lifetime	20 years	10 years	10 years
O&M	0.66 $/kW	0	10% of the variable cost
Subsidy	-	250 $/kWh (SCE incentive program)	50% of fixed costs (SCE workplace rebate)

Specifically for EVs, there are several parameters to be defined with regard to the state of charge and connecting hours at the facility or home. Similarly 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 safely make their trip back home. 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. As a consequence, 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 at 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 equation A.4: the capacity loss per normalized Wh is $8.70 \cdot 10^{-5}$ and the future replacement cost is 200 $/kWh.

Figure 5: Electric vehicle parameters and time schedule



3.3 Exogenous investment

The main objective of exogenous investment is to fix the amount of DERs installed beforehand, and 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 from each other, even though this exogenous scenario is unlikely in real life because it might not necessarily have the lowest possible cost at the start.

There are several ways to size the amount of installed solar PVs coupled with storage according to electricity needs, available space, and budget. For instance, it possible to offset 100% of the electricity consumption and become totally 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, to reduce the energy consumption during on-peak periods and to 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 (2019) 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 consumption is given by hourly adding the kWh needed multiplied by the percentage offset factor[18]. 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[19].

The addition of storage can be useful to avoid excessive solar exports, reduce maximum demand, and arbitrage electricity throughout the hours of the day. If high feed-in-tariffs are applied, the gain from adding a battery to the facility grid is reduced; in other words, if the utility buys the excess energy from the PVs at a price equal or higher than the applied retail rate, the usefulness of installing storage is greatly reduced[20]. In our case, no assistance program (e.g., feed-in-tariffs and net-metering) or subsidies was applied to check whether Solar PVs would still be profitable under these conditions. 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[21]. 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

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[18] The percentage offset factor was proved in the method not to strongly influence the qualitative results in the following sections. We choose 40% to avoid excessive solar exports to the grid.

[19] 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}=(Average annual week-day consumption . % Offset)/(Full sun equivalent . NREL Watts Factor)

[20] The feed-in tariff program called Renewable Market Adjusting Tariff (ReMAT) by CPUC, which is a program to incentive small renewable generators of less than 3 MW, was suspended for all new contracts (CPUC, 2018) under SCE territory.

[21] 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.

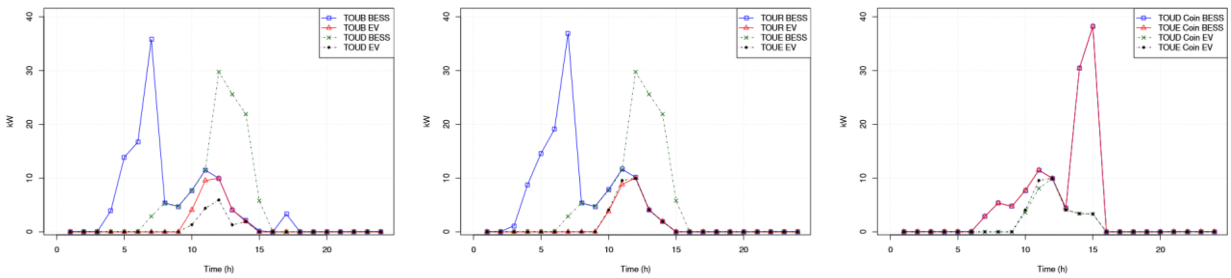
calculated, we formulate four different technology scenarios: PV only, PV+BESS, PV+EV, and PV+EV+BESS[22] under six different tariff structures (TOUB, TOUD, TOUD Coin, TOUR, TOUE, and TOUE Coin) to proceed with our analysis.

4. Results

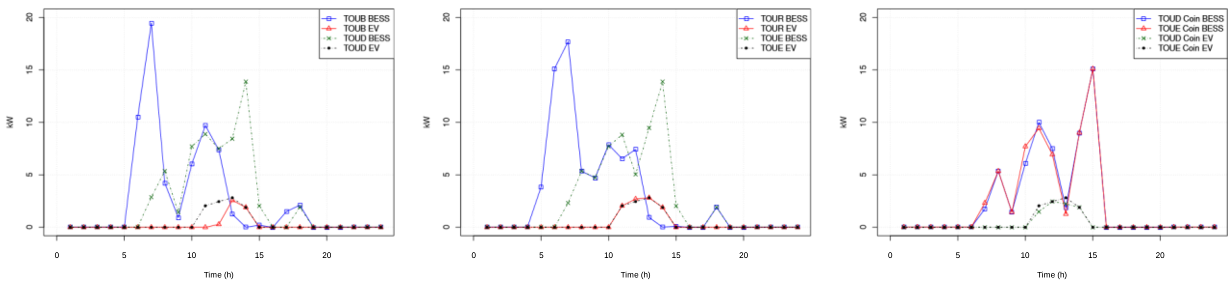
4.1 Charging and discharge strategies

The strategy is to charge the battery and EV during off-peak periods to achieve energy arbitrage objectives and not compromise the private peak demand during that process; the difference lies in which source of electricity the energy comes from (grid or PV). It is not straightforward to track perfectly with which source each DER is charged when there is PV generation and grid connectivity at the same time. The most important thing is to know when the main charging events occur to see whether this will change the private demand significantly.

Figure 6: Charging strategies according to different DER scenarios and tariffs during summer (September)



(a) BESS and EV capacity-based tariffs (b) BESS and EV energy-based tariffs (c) BESS and EV coincident peak tariffs



(d) EV+BESS capacity-based tariffs (e) EV+BESS energy-based tariffs (f) EV+BESS coincident peak tariffs

For the BESS scenario described in figs. 6a to 6c, under the old TOUB tariff, the charging starts at 3-4 AM with electricity from the grid. When the PV starts to generate electricity, it can be used to charge the batteries from 6 AM to 3 PM. On the other hand, under the new TOUD, the battery is charged within the same time period from 6 AM to 3 PM, but the main charging episode now starts at 11 AM, lasting until 4 PM just before the beginning of the on-peak period. Under energy tariffs, the charging strategies show very similar behavior to the respective 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.

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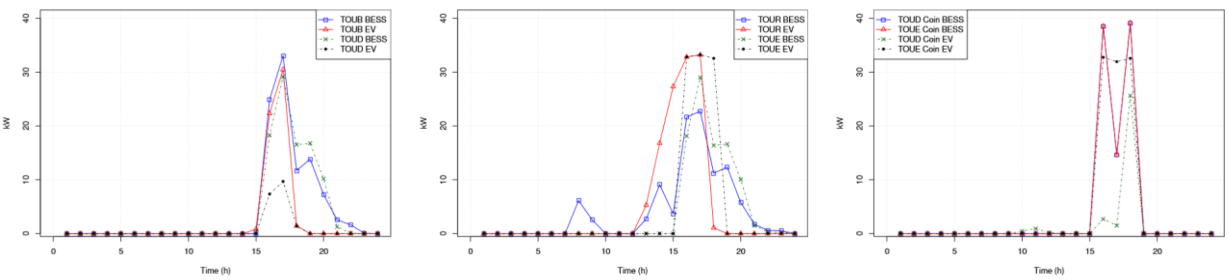
[22] The values of EV and BESS are halved in the last scenario to keep the amount of storage close to the other storage scenarios (e.g., PV+BESS and PV+EV).

Most of the EV charging is done at owners homes during off-peak hours with a specific tariff. However, 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 the home charging. When the two storage forms are present concomitantly (figs. 6d to 6f), the BESS charging is prioritized over EV, while the EV is charged only when there is excess PV electricity generated from 10 AM until 3 PM for all tariffs.

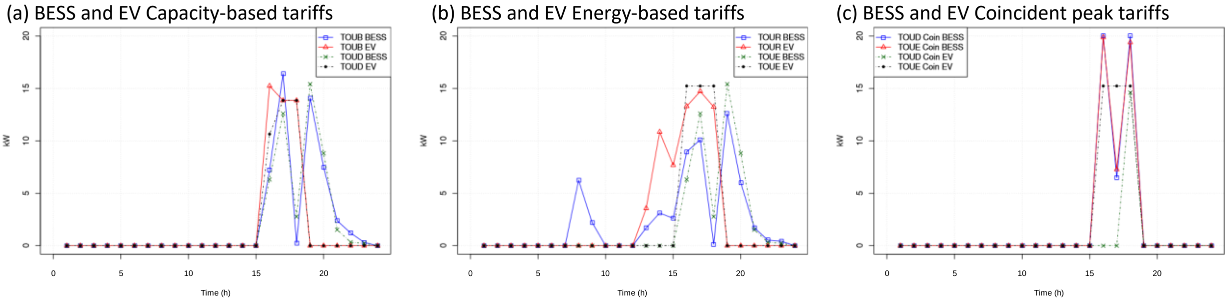
The charging pattern of the total charge, BESS plus EV charging, is closely related to that with the BESS alone, which can be interpreted as an optimum strategy to follow. Finally, under coincident peak tariffs, the same behavior is found as under the other tariffs for the mix.

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 2 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 the maximum private demand, between 15% to 34% outside winter periods when the generation drops[23]. 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.

Figure 7: Discharging strategies according to different DER scenarios and tariffs during summer (September)



(a) BESS and EV Capacity-based tariffs (b) BESS and EV Energy-based tariffs (c) BESS and EV Coincident peak tariffs



(d) EV+BESS Capacity-based tariffs (e) EV+BESS Energy-based tariffs (f) EV+BESS Coincident peak tariffs

Under the capacity tariffs (TOUB and TOUD), the BESS starts discharging primarily to avoid its private peak demand, which is around 45 PM, and tries to offset the on-peak demand as much as possible under TOUD until 9 PM or the mid-peak until 11 PM under TOUB. Under energy-based tariffs (TOUR and TOUE), the BESS discharge is to arbitrage energy between off-peak periods to on-peak. For the new TOUE, it supplies electricity from 3 PM until 9 PM with a peak at around 5 PM to offset the on-peak

[23] The reduction of the maximum private demand and on the hours when the grid is more constrained are analyzed in the next section in detail.

demand concomitantly. Under the TOUR, the discharge begins sooner, at around 12 PM, since the on-peak period also starts sooner (12-6 PM) with an episode starting around 7 AM until 10 AM to reduce non-coincidental demand. We note that the highest amount of energy discharge occurs, except for coincident peak tariffs, at 5 PM, as shown in figs. 7a to 7c when the load is still high and the PV production is almost at its minimum level.

Table 2: Discharging incentives per tariff structure

Tariff	Coin peak MDC	Non-coin MDC	On-peak MDC	Energy arbitrage
TOUB	-	BESS: 3 - 8 PM (5 PM)[a] EV: 3 - 7 PM (5 PM) BESS/EV: 3 - 8 PM (5 PM) /3 - 7 PM (4 PM)	BESS: 3 - 6 PM EV: 3 - 6 PM BESS/EV: 3 - 6 PM/ 3 PM - 6 PM	-
TOUD	-	BESS: 3 - 8 PM (5 PM) EV: 3 - 7 PM (5 PM) BESS/EV: 3 - 8 PM (7 PM) /3 - 7 PM (6 PM)	BESS: 4 - 9 PM EV: 3 - 6 PM BESS/EV: 4 - 9 PM / 4 - 7 PM	-
TOUD Coin	5 - 7 PM (6 PM)	-	-	-
TOUR	-	BESS: 7 - 10 AM, 12 - 8 PM EV: 12 - 6 PM BESS/EV: 7- 10 AM, 2 - 6 PM / 3 - 7 PM	-	BESS: 1 - 9 PM (5 PM) EV: 12 - 6 PM (5 PM) BESS/EV: 2 - 9 PM (7 PM) / 2 - 7 PM (4 PM)
TOUE	-	BESS: 3 - 8 PM EV: 3 - 7 PM BESS/EV: 3 - 10 PM /3 - 7 PM	BESS: 4 - 9 PM EV: 3 - 7 PM BESS/EV: 4 - 9 PM / 4 - 7 PM	BESS: 4 - 9 PM (5 PM) EV: 4 - 7 PM (5 PM) BESS/EV: 4 - 9 PM (7 PM) / 4 - 7 PM (4 PM)
TOUE Coin	5 - 7 PM (6 PM)	-	-	BESS: 4 - 7 PM EV: 4 - 7 PM BESS/EV: 4 - 7 PM / 4 - 7 PM

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

For EVs, under the capacity tariffs (TOUB and TOUD), the EV starts discharging to avoid primarily the facility private peak demand, which is at 4-5 PM, reducing the demand during the on-peak period for TOUB. Under TOUD, the EVs do not discharge at maximum power to offset the private peak because the battery degradation for the EVs alone would not offset the gains from private peak demand reduction. Besides, 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 energy-based tariffs (TOUR and TOUE), the 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. In the case of the new TOUE, the 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. Under the TOUR, the discharge begins sooner, at around 12 PM, since the on-peak period also starts sooner (12-6 PM) reaching its maximum power (33 kW) at 5 PM. There is no discharging episode starting around 7 AM simply because they are not yet connected this time, proving that the EV discharging strategy is intimately connected to the arrival and departure schedules (figs. 7a to 7c).

For the joint combination of EV+BESS (figs. 7d to 7f), under the capacity tariffs (TOUB and TOUD), the combination EV+BESS tries to replicate the same discharge strategy as the scenario with only BESS. However, in the case of TOUD, 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 possible the on-peak demand under TOUD until 9 PM or the mid-peak until 11 PM under TOUB. Under energy-based tariffs (TOUR and TOUE), the 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 as energy as possible during on-peak times for TOUE and mid-peak times for TOUR[24].

4.2 Peak demand reduction

This section analyzes demand reduction during the electric system's most constrained hours (5-8 PM) and the private peak demand reduction in our four different scenarios under our six tariff structures in tables 3 and 4 and the equivalent tables A.15 to A.18. 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 days and early night hours to be offset by storage. The system peak time is less affected by the PV because it occurs when the generation is starting to come down. However, the private peak is also relatively reduced.

Table 3: Average % change in demand during system peak times for PV and PV+BESS

	PV	PV+BESS					
		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
January	-2.0	-29.8	-30.8	-30.0	-29.8	-33.7	-30.2
February	-5.2	-33.0	-34.0	-37.3	-33.0	-37.3	-37.6
March	-11.0	-37.1	-37.8	-47.2	-37.1	-42.7	-47.4
April	-19.7	-33.8	-34.9	-62.2	-38.6	-56.2	-62.5
May	-23.3	-53.1	-58.3	-70.0	-53.9	-63.3	-70.3
June	-27.0	-36.0	-57.4	-68.7	-56.9	-65.9	-68.7
July	-8.9	-29.2	-43.9	-43.0	-25.0	-43.6	-43.0
August	-7.7	-30.7	-42.7	-41.7	-22.8	-42.5	-41.7
September	-4.4	-28.6	-38.3	-37.0	-23.8	-38.0	-37.0
October	-1.1	-26.6	-32.5	-32.8	-26.6	-32.6	-33.0
November	0.0	-25.8	-26.8	-25.1	-25.8	-27.9	-25.3
December	0.0	-26.3	-27.3	-27.2	-26.3	-30.1	-27.4

[24] 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 main behavior.

Table 4: Average % change in maximum private demand for PV and PV+BESS

	PV	PV+BESS					
		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
January	-2.7	-39.6	-39.6	9.7	-39.6	-36.8	9.7
February	-4.8	-42.7	-42.7	-6.8	-42.8	-39.6	-7.0
March	-15.0	-49.4	-49.4	-18.4	-49.5	-45.5	-18.4
April	-35.5	-64.9	-64.8	-33.9	-64.8	-61.2	-33.9
May	-30.6	-63.2	-63.2	-34.9	-63.3	-60.1	-34.9
June	-34.6	-55.0	-59.1	-37.5	-60.3	-55.2	-37.5
July	-18.9	-45.5	-46.8	-14.7	-43.5	-47.1	-14.7
August	-17.3	-41.7	-45.1	-12.9	-40.1	-45.0	-12.9
September	-14.2	-41.3	-43.4	-9.9	-41.4	-43.8	-9.9
October	-11.3	-44.7	-44.7	11.2	-44.7	-44.7	11.2
November	-3.3	-35.7	-35.7	19.6	-35.7	-34.5	19.6
December	-1.7	-34.9	-34.9	28.8	-34.9	-31.7	28.8

BESS helps to reduce the demand significantly more during system peak times (5-8 PM) than EVs. We calculate inter-DER average factors[25] where we compare the average demand reduction of the BESS scenario with the other two fixing the tariff. They vary between 1.36 and 3.33 for system peak times and -0.41 and 1.79 for total private building demand[26]. The negative factor occurs under coincident peak tariffs when 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. Using EV+BESS the demand reduction is closer to the BESS scenario, because now the battery supports the EV discharge before departure, crossing the threshold where the EV battery use cost (degradation plus energy) would exceed the gains. The average factors vary between 1.08 and 1.28 for system peak times and -0.36 and 1.07 for total private building demand.

An inter-tariff assessment inside a single technology scenario is also of interest to verify the demand reduction due only to change of rates. To this end, inter-tariff average factors were calculated for each DER combination[27]. When BESS is present, the new TOUD and TOUE tariff effectively enhances the demand reduction during the system peak times due to the new on-peak time (average factors between 1.10 and 1.32). On the other hand, they do not change the private peak significantly (factors between 0.97 and 1.01) because the PV already offsets a large part of it. The EVs alone offset more demand under the new energy tariff TOUE due to the low discharge power rate under the new capacity tariff TOUD, factors of 1.26 versus 0.88, respectively.

[25] For technology i ∈ {PV+EV, PV+EV+BESS}, tariff k ∈ {TOUB, TOUD, TOUD Coin, TOUR, TOUE, TOUE Coin} and months m ∈ {January,...,December}, the inter-DER average factor is calculated by a relation between two demand reduction (DR) values: $(1/12)\ .\ \sum_m\ ((DR_{k,m}^{PV+BESS})/\ (DR_{k,m}^{i}))$.

[26] For the average factor x: If x>1, there is an increase in demand reduction; If 0 < x < 1, a decrease in demand reduction is observed; If x<0, demand now is higher than the scenario without any DER.

[27] For technology i ∈ {PV+BESS, PV+EV, PV+EV+BESS}, tariff {k,j} ∈ {{TOUD, TOUB}, {TOUD Coin, TOUD}, {TOUE, TOUR}, {TOUE Coin,TOUE}} and months m ∈ {January,...,December}, the inter-tariff average factor is calculated by a relation between two demand reduction (DR) values: $(1/12)\ .\ \sum_m\ ((DR_{k,m}^{i})/\ (DR_{j,m}^{i}))$.

The coincident peak tariffs compared to the original ones with BESS have a slightly higher demand reduction during the system peak hours (factors between 1.01 and 1.13), except for the EVs which seems to fall quite significantly under this type of tariffs (factors of 2.36 for TOUD Coin 1.91 for TOUE Coin). For the private demand, we have a decrease in the demand reduction in all cases (factors of 0.09 to 0.76) for the same reasons as explained for the inter-DER analysis.

4.3 Net present value

This section assess 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. 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[28]. Table 5 gives the result for the four technology scenarios where general observations can be made, and the average total electricity costs are available in table A.19. First, the BESS alone is the scenario where there is the most significant cost reduction, followed closely by the BESS+EV. 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 thus decreases. The difference in savings made by moving towards new tariffs is greater under energy tariffs (from TOUR to TOUE) because PV production is synchronized with on-peak periods of former tariffs, reducing the total electricity cost more. Under the capacity type, the cost reductions are almost the same, due to a similar discharging strategy being adopted when there is no PV production at the end of the afternoon. Finally, under coincident peak tariffs, the electricity cost shortfall under coincident peak capacity tariffs outruns the reduction of the former one (TOUD), which does not occur under energy tariff despite the reduction increase.

Table 5: Average percentage total electricity costs change (%)

PV		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
	Baseline						
	TOUB	-37.0	-29.7	-26.1	-51.3	-36.2	-31.1
	TOUR	-34.4	-27.7	-24.3	-47.8	-33.7	-29.0
PV+BESS		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
	Baseline						
	TOUB	-53.8	-46.1	-47.7	-64.6	-54.1	-52.1
	TOUR	-50.1	-42.9	-44.3	-60.1	-50.3	-48.4
PV+EV		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
	Baseline						
	TOUB	-44.2	-34.1	-41.0	-57.2	-44.3	-44.9
	TOUR	-41.2	-31.8	-38.1	-53.3	-41.2	-41.8

[28] For baseline tariff j ∈ {TOUB, TOUR} and tariff k ∈ {TOUB, TOUD, TOUD Coin, TOUR, TOUE, TOUE Coin}, the percentage change in total electricity costs (TEC) of moving from the baseline tariff j to the new tariff k with technology i ∈ {PV, PV+BESS, PV+EV, PV+EV+BESS} is calculated by: $((TEC_k^i - TEC_k^{base}) / (TEC_j^{base}))$.

PV+EV+BESS		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
	Baseline						
	TOUB	-50.9	-42.9	-43.7	-62.5	-50.6	-48.2
	TOUR	-47.4	-39.9	-40.6	-58.1	-47.1	-44.8

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%[29].

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. The basecase electricity value for the new one is considerably lower, affecting the NPV negatively. The scenario under the energy tariff is even worse due to the smaller reduction in costs with DER installation and the lower base case compared to the corresponding old tariff. The most substantial positive return is under the TOUR tariff due to the PV generation being in phase with the load on-peak period even without any complementary financial help such as feed-in tariffs or net-metering schemes. However, the PV seems to be oversized under all the other rates, leading to negatives returns and implying the need for storage to store as much of the surplus as possible.

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 towards the coincident capacity tariff. However, in some facilities, the load at the coincident peak time (6 PM) is so small that even with 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.

The EVs as the standalone storage have the worst performance in all the scenarios observed in this NPV analysis. Inspecting the inter-tariff variation in the EV scenarios, these feel the NPV reduction less when we move towards coincident tariffs; in other words, their NPV has the highest percentage increase or the lowest decrease with the new tariffs as a baseline. This finding indicates that EVs may be suitable for offsetting a specific demand period under coincident peak tariffs leading to high economic gains. All the results concerning net present values using the scenario without any DER installed for each tariff as the baseline are summarized in Table 6.

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

Table 6: Net present value by rates and technology scenarios

Net present value with solar PV ($)						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Mean	-20,640	-68,789	-97,049	74,538	-27,052	-57,748
(St. Dev.)	(23,016)	(34,848)	(60,899)	(47,008)	(18,041)	(40,869)
#> 0[a]	1	0	0	5	0	0
Net present value with solar PV+BESS ($)						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Mean	48,472	-17,518	-11,573	113,723	33,772	22,572
(St. Dev.)	(40,962)	(18,285)	(41,171)	(61,634)	(20,822)	(43,053)
#>0	5	1	3	5	5	3
Net present value with solar PV+EV ($)						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Mean	-11,580	-71,684	-44,290	71,759	-17,767	-20,134
(St. Dev.)	(33,869)	(40,185)	(43,643)	(53,379)	(16,246)	(38,043)
#>0	2	0	0	5	0	2
Net present value with solar PV+EV+BESS ($)						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Mean	39,320	-25,651	-26,989	103,851	19,142	3,589
(St. Dev.)	(35,063)	(21,677)	(38,990)	(61,413)	(17,814)	(39,031)
#>0	4	0	2	5	4	3

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

4.4 Avoided costs

The total avoided costs will, in theory, be directly linked to the demand reduction during system on-peak hours 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 is when 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. Case 2 is when 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 final aggregated and average avoided costs, in other words, quantitatively. 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 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.

For case 1 using BESS, the shifting of on-peak periods does increase the avoided costs, as it gives more incentive to discharge during this time window. Recalling that the PV tends to offset a significant amount of the demand in the middle of the day, the discharge strategies of old and new tariffs will be quite similar. However, the weighting on the later hours by the new ones plays a more critical role in increasing the avoided costs by 14% from TOUB to TOUD and 15% from TOUR to TOUE. The coincident peak rates increase 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 scenario in which most of the avoided costs are energy-related (67% against 32% from capacity-related costs), in the BESS case, the capacity costs account for almost half of the total in all tariffs, indicating 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 7).

Table 7: Average avoided cost for PV and PV+BESS - Case 1

	Solar PV ($)	Solar PV+BESS ($)					
		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total mean	9,505	15,239	17,501	17,141	14,876	17,201	17,154
(St. Dev.)	(4,806)	(7,531)	(8,503)	(8,155)	(7,675)	(8,400)	(8,153)
Energy	6,382	7,984	9,042	8,457	7,749	8,767	8,460
(St. Dev.)	(3,227)	(3,994)	(4,447)	(4,217)	(3,895)	(4,332)	(4,208)
Capacity	3,123	7,256	8,459	8,684	7,127	8,434	8,694
(St. Dev.)	(1,579)	(3,584)	(4,090)	(4,035)	(3,809)	(4,108)	(4,040)

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, 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 capacity tariffs, but the performance is better under energy tariffs, indicating that the closer the on-peak periods are to the systems, the higher the avoided costs. The combination EV+BESS performs mid-way between the other two technology scenarios with storage, as shown in Table 8.

Table 8: Average avoided cost for PV+EV and PV+EV+BESS - Case 1

Avoided costs of solar PV+EV ($)						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total mean	11,222	10,104	12,539	12,474	14,826	15,340
(St. Dev.)	(5,623)	(5,534)	(6,117)	(6,379)	(7,427)	(7,391)
Energy	6,787	6,578	7,151	7,096	7,326	7,707
(St. Dev.)	(3,464)	(3,460)	(3,504)	(3,639)	(3,735)	(3,757)
Capacity	4,435	3,525	5,389	5,378	7,500	7,632
(St. Dev.)	(2,174)	(2,081)	(2,644)	(2,744)	(3,740)	(3,690)
Avoided costs of solar PV+EV+BESS ($)						

	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total mean	13,989	14,459	14,916	14,747	16,127	16,332
(St. Dev.)	(7,632)	(7,448)	(7,665)	(7,944)	(8,308)	(8,259)
Energy	7,735	8,078	7,780	7,851	8,355	8,098
(St. Dev.)	(4,069)	(4,160)	(4,000)	(4,096)	(4,267)	(4,133)
Capacity	6,254	6,381	7,136	6,896	7,771	8,234
(St. Dev.)	(3,583)	(3,299)	(3,710)	(3,857)	(4,049)	(4,171)

With regard to cases 1 and 2 (tables A.20 and A.21), 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. Normally, 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 non-avoided costs for the charge during the weekday. The difference between avoided costs for discharge and non-avoided cost of charge between the two cases (case 2 minus case 1) will therefore be negative.

4.5 Cost-shifting

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[30]. 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, contributing to the death spiral of utilities (Simshauser, 2016), to recover all the utility costs, mainly those related to the electric network usage. 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 avoiding 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. According to Table 9, in case 1, the new tariffs present lower cost-shifting values than the old ones, not only because they have higher avoided costs in most cases, the exception being the avoided costs under capacity tariff for EVs, but because they also reduce the annual electric savings. Capacity tariffs have significantly lower cost-shifting than energy tariffs since the PV does not bring as high electricity gains in this case. The high private gains outweigh the higher avoided costs under energy tariffs. Regarding coincident peak tariffs, the cost-shifting is lower under energy tariffs due to practically unchanged avoided costs and the lower electricity savings. On the other hand, under coincident capacity rates, the batteries and EVs are incentivized to frame grid constrained periods and increase their savings, while the avoided costs drop for batteries and 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[31].

[30] 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.

[31] The results of case two in Table A.22 are analogous to case one, and the qualitative analysis is roughly the same.

Table 9: Average cost-shifting measures by technologies and tariffs - Case 1

	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
PV - Mean ($)	10,950	6,973	4,637	18,855	10,421	7,884
(St. Dev.)	(6,228)	(4,193)	(1,912)	(10,005)	(5,276)	(5,489)
PV+BESS - Mean ($)	14,544	8,004	8,855	20,839	12,542	11,663
(St. Dev.)	(8,705)	(5,433)	(4,574)	(11,296)	(6,419)	(7,353)
PV+EV - Mean ($)	13,268	8,936	9,722	19,202	9,611	9,532
(St. Dev.)	(7,775)	(5,635)	(4,416)	(10,426)	(5,293)	(6,199)
PV+EV+BESS - Mean ($)	14,292	9,381	8,949	19,837	11,770	10,403
(St. Dev.)	(7,948)	(5,767)	(4,150)	(10,473)	(5,840)	(6,381)

4.6 Value created by electric vehicles

In our study case, only the charging infrastructure is owned by the commercial facilities, the EVs themselves belonging to the employees. There is therefore a financial flow between these two players (recall Fig. 5). This flow will depend on the electricity costs during home charging, battery degradation caused by the facility's grid usage and electricity bill reduction due to EV energy services provided[32]. The sum of these three parts will form the final value of this financial flow. If the value is positive, the flow will be from the facility towards the EV owners; if it is negative, the flow will be the other way (see A.4). 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 (2019), 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 distribution key value is defined between facility and EV owners, and our goal is to achieve the maximum amount of revenue to be split between them.

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. 8, the highest remuneration occurs under coincident demand tariffs, where EV can offset demand charges under a shorter time period compared to on-peak demand and even non-coincidental demand, which can last for several hours. Therefore, under capacity tariffs (TOUB and TOUD) the EVs are not well-adapted to covering all this time window to offset demand. The revenue obtained with the energy services is the largest part under coincident peak tariffs, which demonstrates a high added value to reduce private demand and at a lower cost than stationary batteries. For energy tariffs (TOUR and TOUE), the total revenues are quite high compared to the capacity revenues. However, the most considerable part is the battery degradation component, suggesting that more kWhs needing financial compensation are exchanged via the EV. Unlike the many studies on EVs providing energy services to the grid, here we consider battery degradation as an important factor influencing the 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, the total amount can still be part of the distribution key 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

[32] The value is calculated by the difference between the total energy costs in the scenario without EVs and the one with the EV providing services to the facility's grid.

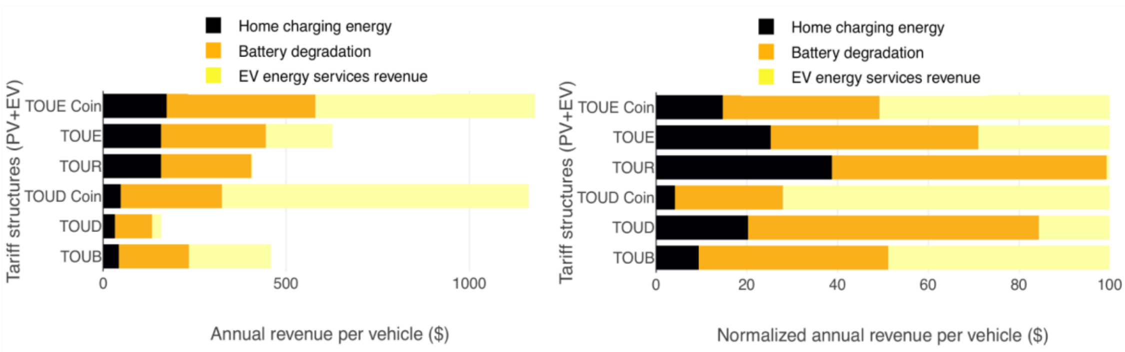
PV+EV+BESS one due to the higher number of vehicles present (twice as many). The competition between them thus decreases the amount received by any vehicle.

5. Endogenous investment

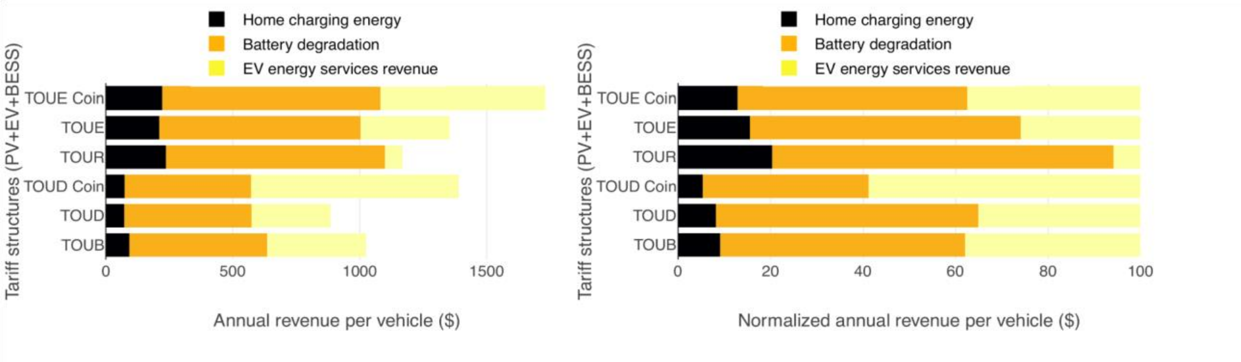
This last section considers the endogenous investments, letting the model choose the optimal amount of DER for each facility to minimize their costs. This exogenous assessment was made to explore the effects of changing tariffs and their influence on private financial value, avoided costs, cost-shifting, and EV remuneration. It will extend the analysis by demonstrating what investments facilities might make, acting rationally.

Table 10 shows the mean capacity installed in the facilities of each DER type by tariff. Regarding PV capacity, energy tariffs present the highest amount installed mainly under the old TOUR tariff, when onpeak period is synchronized with solar generation. Capacity tariffs present a reduction of this capacity to the equivalent energy one. In no facility under coincident capacity tariff (TOUD Coin) was the PV installed, due to the low demand offset during the coincidental hour (see Table 3). The model also chooses to use stationary batteries in all facilities, except under TOUD Coin, both to offset maximum demand charges and arbitrage energy between different time windows. Under capacity rates, stationary storage is attractive under old TOUB, where these can help the solar PVs to offset on-peak demand in the middle of the day when the load is highest for the bell profile of the facilities. On the other hand, under new TOUD, less storage is needed, due to the lower demand to be reduced at these hours of the day. For energy rates, the opposite holds, when the new TOUE tariff needs more storage to arbitrage energy in the day as much as possible toward late afternoon when there is not enough solar PV electricity generation. EVs are mostly present under coincident peak tariffs rate class showing that they are more suitable candidates for offsetting coincidental maximum demand charges during a short time window than batteries, without considering the distribution key.

Figure 8: Exogenous investment average EV revenue per vehicle



(a) Average EV revenue per vehicle per year - PV+EV case ($)



(b) Average EV revenue per vehicle per year - PV+EV+BESS case ($)

Regarding private financial returns, we analyze the average electricity cost reduction and the net present value considering all investment costs (see Table 11). 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, especially under TOUR, as on-peak periods occur during the afternoon. Economic gains under capacity tariffs 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 tariffs, the exception being coincident peak tariffs. Looking closer at these tariffs, the TOUD Coin rate shows a higher NPV than the other capacity tariffs with the same electricity change as TOUD but using only EVs, while TOUE Coin also outpaces TOUE. This last finding proves that EVs are more cost-efficient than stationary batteries in offsetting coincident demand during a short time window under any tariff type.

As expected from the exogenous results, the highest avoided costs are found under energy tariffs in which there is more solar PV generation and more installed storage to arbitrage energy towards 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 share of storage compared to solar PVs. Unsurprisingly, under the new energy tariff TOUE, the avoided costs are greater than the corresponding ones in the old tariff justified by the higher investment in storage. Even so, the main incentive to invest in storage is to reduce maximum demand charges, and in this type of tariff the spread between on-peak and off-peak is reasonably high. This justifies the adoption of more storage than the equivalent capacity tariff.

Table 10: Average DER amount in endogenous case

	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
PV	68.6	32.2	0.0	92.2	77.2	67.4
(St. Dev.)	(22.7)	(21.0)	(0.0)	(45.8)	(25.3)	(26.2)
#> 0^{a}	5	5	0	5	5	5
BESS	168.4	83.2	2.2	134.8	235.2	192.8
(St.Dev.)	(111.2)	(65.4)	(-)	(50.9)	(73.0)	(67.4)
#>0	5	5	1	5	5	5
EV	69.6	69.8	475.4	46.4	164.2	162.4

(St. Dev.)	(33.5)	(58.5)	(269.8)	(0.0)	(273.1)	(233.4)
#>0	4	3	5	2	3	5

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

Table 11: Private financial gains - Endogenous case

Average total electricity costs - Endogenous case						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Basecase	54,689	50,144	44,724	58,868	57,517	53,568
(St. Dev.)	(26,111)	(23,538)	(21,022)	(28,504)	(27,012)	(26,698)
With DER	29,950	37,554	32,197	25,508	27,685	26,337
(St. Dev.)	(16,975)	(17,452)	(14,591)	(13,607)	(16,713)	(15,904)
Average percentage total electricity costs change - Endogenous case						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Baseline						
TOUB	-46.23	-22.70	-22.80	-61.13	-56.11	-50.62
TOUR	-43.09	-21.23	-21.14	-56.97	-52.14	-46.98
Average net present value (NPV) - Endogenous case						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Mean NPV	73,228	30,718	90,233	125,623	55,558	64,108
(St. Dev.)	(45,500)	(22,225)	(53,190)	(59,846)	(29,053)	(55,671)
#> 0[a]	5	5	5	5	5	5

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

Cost-shifting issues are more critical among energy tariffs due to more significant private savings, as shown in Table 12. The shift towards the new tariffs substantially decreases cost-shifting concerns driven by a reduction in solar PV investment. Consequently, a shortfall in the profit occurs once the generation is no longer valued at on-peak times. First, for the new capacity tariff, the savings from reduced electricity consumption are higher than the decrease in avoided costs caused by the reduction in solar PVs. In the energy rate case, the private savings then decrease at the same time as the total avoided costs increase, both contributing to the reduction of cost-shifting values. Finally, coincident peak tariffs show similar values of cost-shifting to their original rates, especially the TOUD Coin, for which we obtained the second-lowest cost-shifting concomitantly with the second-highest NPV 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 A.23, and they are qualitatively analogous to the exogenous case.

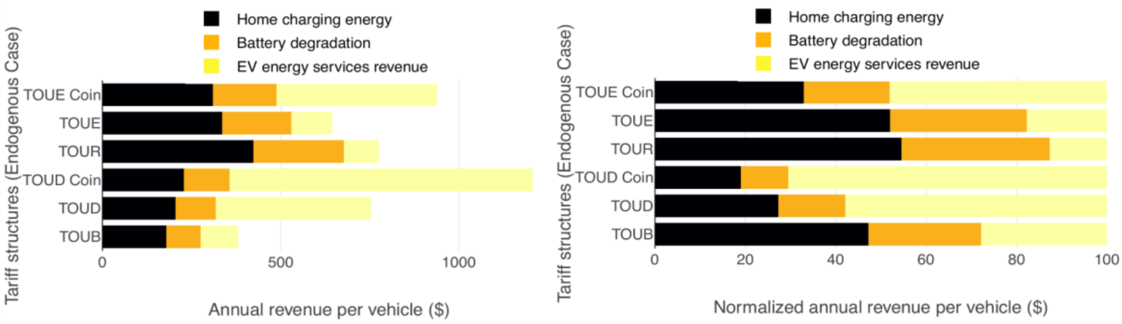
Table 12: Average avoided costs and cost-shifting - Endogenous case

Avoided costs - Endogenous case 1						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total Mean	11,452	6,278	6,014	12,818	22,127	18,843
(St. Dev.)	(4,771)	(4,005)	(3,527)	(6,143)	(10,142)	(8,590)
Energy	4,893	2,625	1,739	6,368	8,645	7,954
(St. Dev.)	(1,614)	(1,713)	(991)	(3,128)	(3,484)	(3,226)
Capacity	6,559	3,653	4,275	6,450	13,482	10,889
(St. Dev.)	(3,164)	(2,434)	(2,537)	(3,063)	(7,294)	(5,441)
Cost shifting - Endogenous case 1						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total Mean	13,287	6,312	6,513	20,543	7,704	8,388
(St. Dev.)	(6,767)	(4,338)	(3,751)	(10,122)	(1,972)	(4,747)

The last point to be analyzed is the EV remuneration for the endogenous case shown in Fig. 9 with more numerical details present in table A.24. 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, the charging stations were not installed in all the facilities according to each tariff structure studied, the exception being the coincident peak tariffs. First, under capacity tariffs, the remuneration is the lowest of all the scenarios, demonstrating the inability of EVs to offset demand during an extended period, although proportionally, the highest revenue share comes from energy services.

Under energy tariffs, the number of vehicles present is lower, and their remuneration strongly depends on the price of electricity during home charging and overall battery degradation. This is because these two factors are the highest shares of their total remuneration, respectively. The revenue from energy services to the facility is the smallest share 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, all facilities installed charging stations. The stations enable the EVs to provide high value to the facilities by offsetting the coincident peak demand at around 6 PM. The TOUD Coin and TOUE Coin rates have an annual average revenue of \$1207 and \$939.7 respectively per EV, in which the highest share of the remuneration does not depend on battery degradation and electricity home pricing.

Figure 9: Average EV revenue per vehicle - Endogenous case



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. Five load profiles of commercial buildings in Los Angeles suburbs with representative R-squared values were used as a sample under South California Edison's C&I tariffs. 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.

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 energy tariffs, especially if on-peak periods were synchronized with the period when there was generation. For capacity tariffs, as the PV generation is synchronized with the load of the facilities, it already reduces a fair amount of the maximum private demand, so the storage focuses more on lowering the net building demand during the end of the on-peak period. The BESS alone showed the highest NPV under all tariffs, with negative returns only under the new capacity tariffs with on-peak periods at the end of afternoon, followed by the EV+BESS mix but with lower yields. The couple EV+PV alone did not show financial attractiveness, due to the high costs of oversized PVs under capacity tariffs and too many EVs under energy tariffs to arbitrage energy, causing battery degradation, so the right amount has yet to be found with the endogenous investment. On the utility side, the new tariffs with on-peak periods placed in the period when the grid is more constrained often presented lower cost-shifting compared to the old ones for this type of load profile. The lowest cost-shifting values were found under capacity tariffs, due to the reduction of electricity savings. The last aspect we analyzed is the total EV remuneration, which includes home electricity charging costs, battery degradation compensation, and the revenue due to energy services provided for the facility. We found that EVs were well-adapted to offsetting coincident demand with either capacity or energy tariffs, occurring in a short time window, indicating that they are more efficient than the stationary battery for coincident peak rates and with the highest remuneration. Although bill management can be the topmost remunerated service for EVs, it still strongly depends on the type of tariff and the contract to split gains between EV owners and the facilities.

The endogenous investment revealed how the facility would invest rationally to minimize its costs. The average DER capacity installed often used PV-EV-batteries to reduce its electricity costs, except under the capacity coincident rate, indicating that the mix can work together to support the facility grid, each one bringing its own benefits. The maximum net present value was found under the energy rate with on-peak period synchronized with PV generation. It was more than $100,000 when the PV generation was synchronized with on-peak periods. The lowest cost-shifting was under the capacity tariff, with the on-peak period framing the more constrained grid period at around 6 PM. However, coincident peak tariffs, especially capacity ones, coupled with EVs, were noteworthy here for their excellent performance. We obtained the second-highest NPV, the second-lowest cost-shifting, and the highest EV remuneration. 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 (810 AM) or even later evening (911 PM). Regarding EVs, remuneration varied between $380 and $1208. The high compensation can attract more EV owners, raising competition among them to provide this type of service, probably leading to a reduction of the yearly revenue per EV.

General policy recommendations can be made to regulators using tariffs as instruments to push forward certain technologies. Energy tariffs with on-peak periods synchronized with solar PV production from around midday until late afternoon, especially if combined with feed-in-tariffs or net-metering schemes, will often be profitable for the private facility investors. Even so, this is the worst case for cost-shifting concerns. 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. 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 can be made by DERs, although multi-objective optimization taking into account CO2 emission reduction is also well-represented. 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 the super off-periods or more location-specific tariffs taking into account distribution locational marginal pricing components now warrant investigation.

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];
  - *EV CL*: Electric vehicle capacity loss per normalized Wh [dimensionless];
  - *EV FRC*: 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 [$];
  - $\underline{CV\,ar}cost_i$: Variable capital cost of technology i [$/kW or $/kWh];
  - SOC_k:Maximum state of charge for technology k [dimensionless];
  - $\underline{SOC_k}$: Minimum state of charge for technology k [dimensionless];
  - ϕ_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];
  - $E_{m,h}^{r\rightarrow c}$: Electricity flow from the residential building to the car [kWh];
  - $E_{m,h}^{c\rightarrow r}$: 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:

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

Where:

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

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

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

Main constraints:

1. Energy balance

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

2. PV output constraint

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

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

3. Storage constraints

$$SIn_{k,m,d,n} \ 6 \ Cap_k \cdot SCRate_k \forall\, k,m,d,h. \tag{A.9}$$

$$SOut_{k,m,d,n} \ 6 \ Cap_k \cdot SDCRate_k \forall\, k,m,d,h. \tag{A.10}$$

4. General constraints

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

$$UL_{m,d,h} \leqslant Psb_k \cdot M \ \forall\, m,d,h. \tag{A.11}$$

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

$$Cap_i \leqslant Pur_i \cdot M \ \forall\, i. \tag{A.13}$$

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

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

Table A.13: SCE's General Services 2 electricity retail tariffs

	TOUB	TOUD	TOUR	TOUE
Energy Charge ($/kWh)				
Summer on-peak	0.08819	0.11963	0.34963	0.48887
Summer mid-peak	0.08393	0.11016	0.16665	0.16322
Summer off-peak	0.08139	0.08055	0.09191	0.11227
Winter mid-peak	0.10273	0.09781	0.11663	0.15888
Winter off-peak	0.07183	0,0862	0.07582	0.08962
Winter super off-peak	0	0.06441	0	0.07599
Non coincidental demand charges ($/kW)	16.07	10.35	10.24	7.49
Time-specific demand charges ($/kW)				
Summer on-peak	13.94	19.85	0	4.35
Summer mid-peak	4.63	0	0	0
Winter mid-peak	0	4.02	0	0.85
Monthly fixed charges ($/month)[a]	129.9	129.9	129.9	129.9

a

Fixed charges are the sum of customer charge, single phase service and TOU option meter charge

Table A.14: SCE's General Services 2 electricity retail tariffs time schedule

	TOUB and TOUR	TOUD and TOUE
Summer months (June 1st - September 30th):		
Summer on-peak	Weekdays: 12 PM - 6 PM	Weekdays: 4 PM - 9 PM
Summer mid-peak	Weekdays: 8 AM to 12 PM; 6 PM - 11 PM	Weekends: 4 PM - 9 PM
Summer off-peak	Weekdays: 11 PM to 8 AM; Weekends: All hours	Weekdays and weekends: All hours except 4 PM to 9 PM
Winter months (October 1st - May 31st):		
Winter on-peak		Weekdays and weekends: 4 PM to 9 PM
Winter mid-peak	Weekdays: 8 PM - 9 PM	
Winter off-peak	Weekdays: 9 PM to 8 AM; Weekends: All hours	Weekdays and weekends: 9 PM to 8 AM
Winter super off-peak		Weekdays and weekends: 8 AM to 4 PM

Table A.15: Average % change in demand during system peak times for PV and PV+EV

	PV+EV					
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
January	-7.4	-9.0	-18.8	-7.4	-8.1	-18.8
February	-9.9	-11.5	-22.9	-9.9	-9.9	-22.9
March	-14.3	-14.9	-30.6	-14.3	-14.9	-30.6
April	-20.0	-20.0	-41.0	-20.1	-20.0	-41.0
May	-23.6	-23.6	-43.8	-23.7	-23.6	-43.8
June	-39.8	-27.4	-45.1	-40.5	-58.5	-58.5
July	-22.3	-12.6	-29.5	-26.0	-46.7	-46.7
August	-21.3	-10.6	-28.6	-24.8	-45.5	-45.5
September	-17.8	-7.8	-25.8	-22.1	-42.9	-42.9
October	-4.8	-4.8	-23.0	-4.8	-4.8	-23.0
November	-10.0	-10.0	-16.6	-10.0	-10.0	-16.6
December	-9.4	-9.4	-17.5	-9.4	-9.4	-17.5

Table A.16: Average % change in maximum private demand for PV and PV+EV

PV+EV						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
January	-16.6	-16.6	-10.3	-16.6	-16.6	-10.3
February	-18.7	-18.7	-14.2	-18.7	-18.7	-14.2
March	-24.0	-24.0	-20.2	-24.1	-24.0	-20.2
April	-36.6	-36.6	-36.0	-36.7	-36.6	-36.0
May	-34.9	-34.9	-30.9	-35.0	-34.9	-30.9
June	-38.4	-38.4	-34.8	-38.5	-38.4	-38.4
July	-33.2	-33.2	-20.2	-33.1	-33.2	-33.2
August	-29.4	-29.4	-19.1	-29.3	-29.4	-29.4
September	-27.8	-27.8	-16.6	-27.3	-27.8	-27.8
October	-25.9	-25.9	-12.8	-25.9	-25.9	-12.8
November	-21.4	-21.4	-6.7	-21.4	-21.4	-6.7
December	-19.3	-19.3	-4.9	-19.3	-19.3	-4.9

Table A.17: Average % change in demand during system peak times for PV and PV+EV+BESS

PV+EV+BESS						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
January	-24.4	-25.0	-22.4	-23.0	-25.7	-22.5
February	-27.8	-28.8	-27.8	-26.4	-30.0	-27.9
March	-30.9	-31.0	-35.4	-30.9	-33.3	-35.5
April	-40.9	-40.6	-47.5	-41.0	-47.2	-47.6
May	-44.7	-44.9	-52.1	-44.3	-49.1	-52.3
June	-44.2	-49.8	-56.2	-51.3	-60.7	-66.3
July	-25.0	-37.5	-34.2	-29.4	-45.5	-46.6
August	-28.9	-36.2	-32.6	-26.9	-43.3	-43.7
September	-27.7	-32.3	-29.8	-26.2	-38.7	-38.8
October	-25.3	-28.1	-27.0	-24.7	-28.4	-27.1
November	-25.2	-25.8	-20.1	-25.2	-25.1	-20.2
December	-21.4	-21.6	-21.1	-20.5	-23.1	-21.3

Table A.18: Average % change in maximum private demand for PV and PV+EV+BESS

	PV+EV+BESS					
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
January	-34.9	-33.7	-10.8	-33.7	-32.3	-10.8
February	-38.2	-38.2	-14.8	-36.9	-36.5	-14.9
March	-43.7	-43.7	-20.8	-43.8	-41.8	-20.9
April	-57.9	-57.9	-36.6	-58.0	-56.6	-36.6
May	-57.1	-56.9	-33.6	-57.0	-56.2	-33.6
June	-55.2	-55.7	-37.7	-57.1	-52.8	-38.4
July	-46.1	-46.8	-27.0	-44.5	-46.7	-33.2
August	-43.4	-44.3	-25.1	-41.0	-43.8	-28.3
September	-42.6	-43.1	-22.2	-41.8	-43.1	-24.6
October	-43.5	-43.4	-18.2	-43.1	-43.6	-18.2
November	-35.2	-35.2	-7.3	-35.2	-34.6	-7.4
December	-30.4	-30.2	-4.9	-29.7	-29.2	-5.0

Table A.19: Total building electric costs per techology scenario

	Total building electric costs ($)					
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Basecase	54,689	50,144	44,724	58,868	57,517	53,568
(St. Dev.)	(26,111)	(23,538)	(21,022)	(28,504)	(27,012)	(26,698)
PV	34,233	33,667	30,582	30,508	37,591	36,179
(St. Dev.)	(15,394)	(14,895)	(14,876)	(13,899)	(17,183)	(17,306)
PV+BESS	24,905	24,640	18,728	23,154	27,774	24,751
(St. Dev.)	(10,669)	(10,359)	(8,671)	(10,131)	(12,432)	(11,657)
PV+EV	30,198	31,104	22,463	27,193	33,079	28,697
(St. Dev.)	(13,207)	(13,110)	(10,797)	(12,044)	(14,742)	(13,603)
PV+EV+BESS	26,408	26,304	20,860	24,284	29,620	26,834
(St. Dev.)	(11,048)	(10,881)	(9,612)	(10,538)	(13,093)	(12,504)

Table A.20: Average avoided cost for PV and PV+BESS - Case 2

	Solar PV ($)	Solar PV+BESS ($)					
		TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total mean	9,505	15,664	17,410	16,863	15,027	17,075	16,876
(St. Dev.)	(4,806)	(8,065)	(8,551)	(8,012)	(8,059)	(8,445)	(8,011)
Energy	6,382	8,018	9,059	8,436	7,766	8,768	8,439
(St. Dev.)	(3,227)	(4,027)	(4,456)	(4,205)	(3,916)	(4,335)	(4,197)
Capacity	3,123	7,647	8,351	8,427	7,260	8,307	8,437
(St. Dev.)	(1,579)	(4,082)	(4,122)	(3,894)	(4,163)	(4,142)	(3,900)

Table A.21: Average avoided cost for PV+EV and PV+EV+BESS - Case 2

Avoided costs of solar PV+EV ($)

	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total mean	11,722	10,521	12,792	12,752	15,051	15,412
(St. Dev.)	(6,115)	(6,057)	(6,218)	(6,641)	(7,669)	(7,385)
Energy	6,814	6,596	7,167	7,112	7,332	7,713
(St. Dev.)	(3,485)	(3,480)	(3,513)	(3,651)	(3,741)	(3,759)
Capacity	4,908	3,926	5,624	5,641	7,719	7,699
(St. Dev.)	(2,644)	(2,584)	(2,738)	(2,996)	(3,968)	(3,682)

Avoided costs of solar PV+EV+BESS ($)

	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total mean	14,887	15,290	14,905	15,050	16,327	16,194
(St. Dev.)	(8,299)	(8,114)	(7,490)	(8,294)	(8,471)	(8,030)
Energy	7,800	8,132	7,788	7,880	8,370	8,096
(St. Dev.)	(4,110)	(4,198)	(4,001)	(4,117)	(4,272)	(4,130)
Capacity	7,087	7,157	7,117	7,169	7,957	8,098
(St. Dev.)	(4,218)	(3,932)	(3,542)	(4,185)	(4,209)	(3,951)

Table A.22: Average cost-shifting measures by technologies and tariffs - Case 2.

	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
PV - Mean ($)	10,950	6,973	4,637	18,855	10,421	7,884
(St. Dev.)	(6,228)	(4,193)	(1,912)	(10,005)	(5,276)	(5,489)
PV+BESS - Mean ($)	14,119	8,095	9,133	20,688	12,668	11,941
(St. Dev.)	(8,100)	(5,312)	(4,728)	(10,851)	(6,329)	(7,428)
PV+EV - Mean ($)	12,768	8,519	9,470	18,923	9,386	9,460
(St. Dev.)	(7,324)	(5,150)	(4,301)	(10,182)	(5,045)	(6,196)
PV+EV+BESS - Mean ($)	13,394	8,550	8,959	19,535	11,569	10,540
(St. Dev.)	(7,381)	(5,174)	(4,282)	(10,146)	(5,657)	(6,628)

Table A.23: Average avoided costs and cost-shifting - Endogenous case 2

Avoided costs - Endogenous case 2						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total Mean	12,368	6,932	6,253	13,199	22,189	18,913
(St. Dev.)	(5,602)	(4,510)	(3,633)	(6,810)	(9,931)	(8,666)
Energy	4,877	2,672	1,749	6,397	8,658	7,944
(St. Dev.)	(1,728)	(1,753)	(996)	(3,159)	(3,491)	(3,218)
Capacity	7,491	4,260	4,504	6,802	13,531	10,969
(St. Dev.)	(3,915)	(2,805)	(2,638)	(3,673)	(7,039)	(5,534)
Cost-shifting - Endogenous case 2						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Total Mean	12,371	5,658	6,274	20,162	7,642	8,318
(St. Dev.)	(6,130)	(3,918)	(3,642)	(9,394)	(2,023)	(4,704)

Table A.24: EV remuneration breakdown - Endogenous case

Average EV remuneration breakdown - Endogenous case						
	TOUB	TOUD	TOUD Coin	TOUR	TOUE	TOUE Coin
Home charging energy	179.5	205.7	229.1	422.9	334.9	309.1
(St. Dev.)	(30.1)	(22.4)	(23.7)	(4.9)	(16.5)	(27.7)
Battery degradation	94.6	111.3	126.7	254.4	194.6	178.4
(St. Dev.)	(19.4)	(14.5)	(15.3)	(8.5)	(10.8)	(17.8)
Energy service	106.1	436.4	852.0	98.5	114.5	452.2
(St. Dev.)	(128.9)	(129.2)	(221.1)	(22.6)	(46.6)	(649.4)
Total mean	380.2	753.4	1,207.8	775.7	644.0	939.7
(St. Dev.)	(166.4)	(128.1)	(250.1)	(9.2)	(73.8)	(673.5)
#> 0[a]	4	3	5	2	3	5

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

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