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Economic Viability of Photovoltaic and Battery Storage Systems for Residential Electric Vehicle Charging in Slovenia

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Abstract.

This paper analyzes the payback periods of investments in photovoltaic and energy storage systems under different electric vehicle charging scenarios in Slovenia, accounting for electricity cost structures. Based on fifteen-minute residential household electricity consumption data, two driving scenarios were evaluated: a high-mileage case with an annual driving distance of approximately 58,000 km and a low-mileage case of approximately 15,000 km. Electrical energy costs were calculated based on the currently applicable electricity billing methodology in Slovenia. Photovoltaic power production was estimated using solar irradiation data corresponding to the system location, module tilt angle, and available installation area on the analyzed residential building. The results present the charging behavior of the energy storage system in relation to household electricity consumption and photovoltaic production. In addition, the impact of integrating an electric vehicle charging station on the electricity consumption profile is assessed. The analysis further identifies the scenarios in which investments in photovoltaic systems and energy storage achieve shorter payback periods, considering the applied electricity pricing and credit note scheme.

Key words. electricity production, battery storage unit, payback period, electric vehicle, electricity cost

1. Introduction

Due to increasing global awareness of environmental impacts, a growing number of drivers are choosing to purchase electric vehicles (EVs). The number of EVs is increasing each year, which is, among other factors, a key contributor to achieving the goal of carbon neutrality by 2050, and this upward trend is expected to continue [1]. The ongoing decarbonization of the energy and transport sectors has accelerated the deployment of distributed renewable energy sources, residential energy storage systems, and EVs. In this context, households are increasingly transitioning from passive electricity consumers to active prosumers, combining local photovoltaic (PV) production with flexible demand and storage technologies. This transformation fundamentally alters residential load profiles and raises new challenges related to electricity pricing, grid interaction, and investment profitability [2]. Residential PV systems have already been demonstrated to be economically viable in many regions, primarily due to increased self-consumption and declining installation costs. Storage systems further improve economic performance by shifting excess PV production to periods of higher demand and electricity prices [3]. However, the profitability of combined PV and battery systems remains highly sensitive to electricity tariffs, billing methodologies, and local market conditions [4]. When coordinated charging strategies are applied, EVs can enhance PV self-consumption and system flexibility; conversely, uncontrolled charging can create new peak loads and increase grid stress [5]. The interaction between EV charging behavior, battery storage operation, and electrical energy pricing has therefore become a central research topic. Advanced pricing schemes such as time-of-use and dynamic tariffs have been shown to influence charging schedules and storage utilization, enabling better alignment between EV demand and solar PV production [6]. Nevertheless, several authors warn that poorly designed tariffs may unintentionally shift demand to new peak periods, highlighting the importance of evaluating integrated systems under realistic billing frameworks [7].
This paper evaluates the payback period of residential PV system and battery storage investments under different EV charging scenarios using 15-minute household consumption data. The analysis explicitly incorporates Slovenia's current electrical energy billing methodology and compares two representative EV usage scenarios characterized by low and high annual driving distances. By focusing on a realistic residential setting, this paper provides insights into how EV charging intensity, tariff structures, and energy management strategies jointly affect electrical energy costs, energy storage operation, and investment profitability.

2. Network tariff system in Slovenia

The network charge is an amount listed on the electrical energy bill that every user of the electrical energy system is obliged to pay for the use of the power system infrastructure. The tariff components used to calculate the network charge are determined by the Energy Agency of the Republic of Slovenia (AGEN) in accordance with the network charge calculation methodology and are divided into four tariff components, which are:

- transmission system network charge,
- distribution system network charge,
- connection capacity network charge, and
- network charge for excessive reactive energy consumption [8].

In addition to the electrical energy consumption profile, the user's billing capacity is a key factor in determining network charges. Billing capacity consists of an agreed billing capacity, defined in advance, and an excess billing capacity, representing demand exceeding the agreed value. The agreed billing capacity is determined by the system operator based on historical 15-minute demand values, in accordance with the Act on the Methodology for Network Charge Calculation (Official Gazette of the Republic of Slovenia, No. 76/2025). Users may request adjustments to the proposed billing capacity, while any exceedance of the agreed value results in additional network charges. Therefore, the appropriate sizing of the agreed power is typically based on peak demand during the high season. Improper selection can lead to increased electrical energy costs.

A. Selected agreed power based on the scenarios

To compare electrical energy costs and payback periods across the considered scenarios, the agreed power (AP) was selected based on the electrical energy consumption profiles, specifically according to the average peak power within each time block. Table 1 presents a comparison of the selected agreed billing capacities for individual time blocks, with the baseline case representing the capacities for the dwelling without a PV system, battery storage, or an EV charging station. Case (a) corresponds to the configuration including an EV charging station, while case (b) represents the configuration with an EV charging station combined with a battery storage system and a PV system.

Table 1. Selected agreed power based on scenarios.

	AP 1 [kW]	AP 2 [kW]	AP 3 [kW]	AP 4 [kW]	AP 5 [kW]
Scen. 1 (a)	13.7	14.2	14.7	14.7	14.7
Scen. 1 (b)	5.9	5.9	5.9	5.9	5.9
Scen. 2 (a)	9.7	9.3	8.7	8.2	6.7
Scen. 2 (b)	3.5	3.5	3.5	3.5	3.5

3. Analyzed residential building

A. Consumption profile

The analysis concerns a detached residential building in eastern Slovenia occupied by a five-person household. Space heating and domestic hot water are provided by an air-to-water heat pump. The building is connected to the public electricity grid via a three-phase 3×25 A connection. Measured load data reveal a highly uneven electrical energy consumption pattern, with an average demand of 1.457 kW, a peak demand of 8.42 kW, and an annual consumption of 12,759 kWh. Seasonal variations are mainly driven by the heat pump operation, as its coefficient of performance (COP) decreases during winter due to lower outdoor temperatures. The corresponding load profile is shown in Figure 1.

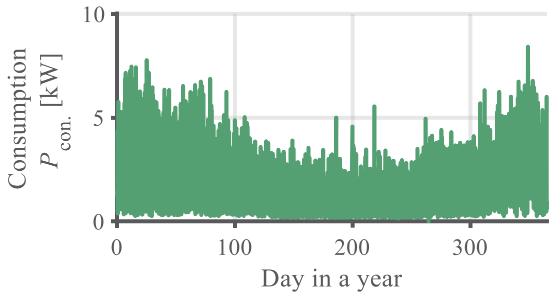

Fig. 1. Consumption of the analyzed residential building.

B. PV system and battery storage

The PV system was designed to produce approximately 20% more electrical energy annually than the household's total demand. This was achieved through a rooftop installation of 24 BISOL BB0 450 PV modules, each rated at 450 W, for a total installed capacity of 10.8 kW. The investment cost of the system was assumed to be 11.800 EUR. The annual electrical energy production of the PV system is presented in Figure 2.

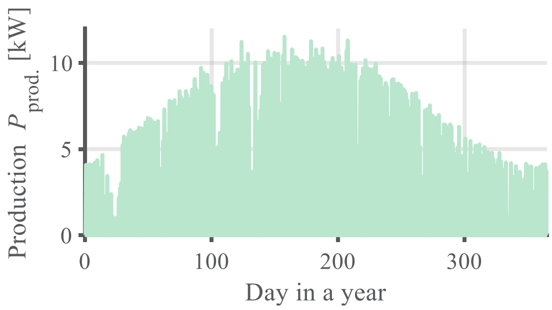

Fig. 2. Annual production of the PV system.

As shown in Figure 2, the PV system delivers an average output power of 1,549 kW, with a maximum production of 11,523 kW. The annual electrical energy production amounts to approximately 13.56 MWh, meeting the design target and exceeding the building's electricity demand. To increase self-consumption and reduce dependence on the public grid, the PV system was supplemented with a battery storage system. A lithium iron phosphate ($LiFePO_4$) battery with a usable capacity of 22.1 kWh was selected, supporting a maximum charging and discharging power of 20.45 kW. The investment cost of the battery system was assumed to be 11,500 EUR, resulting in a total combined investment cost of 23,380 EUR for the PV and battery storage system. The methodology for battery charging is based on user driving patterns (daily mileage of weekdays and weekends, as well as the time periods when EV is available for charging) and charging infrastructure parameters (minimum and maximum charging power). Based on these inputs, the program generates a time-resolved charging profile for a selected calendar year using a rule-based algorithm. At each step, the state of charge (SOC) of the battery is evaluated. If the battery has not reached its nominal capacity, the model determines the available charging window. When the available time is sufficient, the algorithm applies a lower charging power (slow charging), which reduces stress on the electrical grid and leads to a more uniform load profile. Conversely, when the available time is insufficient to reach the required state of charge with low power, the model switches to higher charging power (fast charging). Charging is terminated once the nominal battery capacity is reached.

4. EV charging scenarios

A. Scenario 1

Scenario 1 considers the use of an EV charging station by an owner who travels approximately 200 km per day for work-related commuting (100 km each way), resulting in an annual driving distance of approximately 58,000 km. The vehicle is also used in the afternoon for short trips, such as shopping and other daily errands, with charging mainly occurring during the evening and night. On weekends, the EV is primarily used for trips to a weekend residence located 15 km away. A representative weekday charging schedule is shown in Figure 3a, while a typical weekend charging profile is presented in Figure 3b.

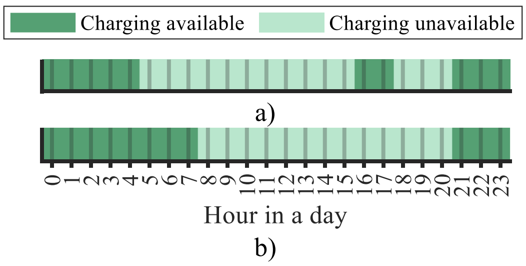

Fig. 3. Charging schedule of EV for scenario 1.

Figure 4 presents a comparison of the consumer's electrical energy consumption with the EV charging station included under Scenario 1, in the case where the consumer does not have a PV system or an electrical energy storage system installed.

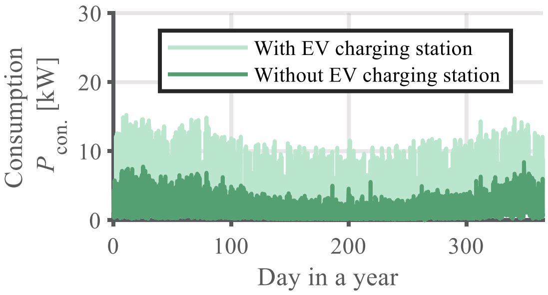

Fig. 4. Electrical energy consumption profile of a consumer with an integrated EV charging station under Scenario 1, without a PV and battery storage system.

Figure 4 shows that including the EV charging station increases annual electrical energy consumption from 12.76 MWh to 22.63 MWh, a 77.3% increase. Consequently, both the average and the maximum power demand rise accordingly. The average power increases from 1.457 kW to 2.584 kW (77.3%), while the maximum power demand increases from 8.42 kW to 15.25 kW (81.1%). Figure 5 shows the power flow to and from the consumer's grid connection under Scenario 1 with the EV charging station, where the consumer is equipped with a PV system and a battery system. Figure 5a shows the power exchanged with the grid, whereas Figures 5b and 5c depict the battery SOC and the battery power, respectively.

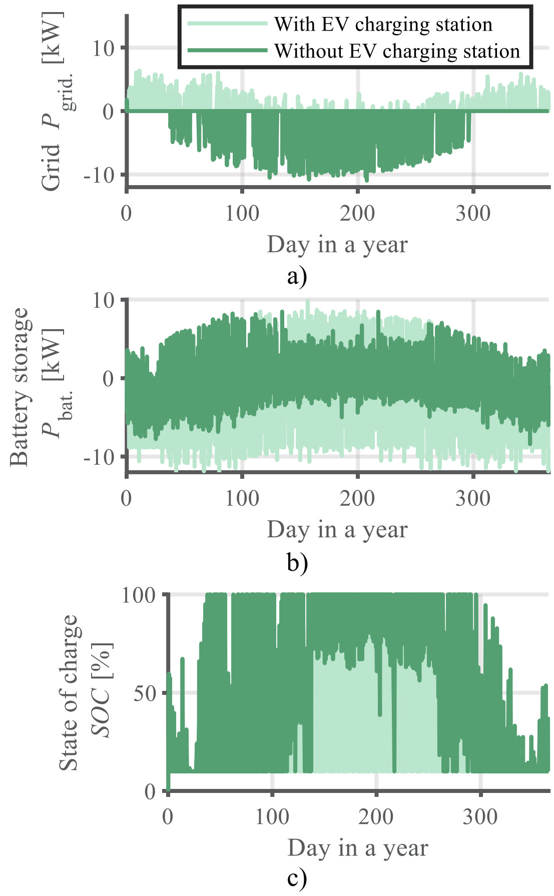

Fig. 5. Power flow profiles between the grid and the battery storage system, and the battery storage SOC for a consumer with an integrated EV charging station under Scenario 1.

As shown in Figure 5a, the electrical energy import profile from the grid changes significantly due to the additional demand introduced by the EV charging station when compared to the case without EV charging. Several periods can be observed during which substantial amounts of electrical energy are drawn from the grid despite the presence of a battery system. The total electrical energy imported from the grid amounts to 901 kWh. This effect is most pronounced during the winter months, when PV system output is insufficient to fully meet total electrical demand. The charging dynamics, which involve higher charging power levels, result in a loss of grid independence even during the summer period. In addition, significant changes in the discharge behavior of the battery storage system are observed. Due to significantly higher daily driving distances and limited available charging time, the charging station must operate at 8 kW to ensure an adequate state of charge for the EV battery.

B. Scenario 2

Scenario 2 considers a user of EVs who travels approximately 20 km per day, resulting in an annual driving distance of about 5,300 km. Charging mainly occurs during the day, while the vehicle remains largely unused on weekends and is therefore not charged. A representative weekday charging schedule is shown in Figure 6a, and a typical weekend charging profile is presented in Figure 6b.

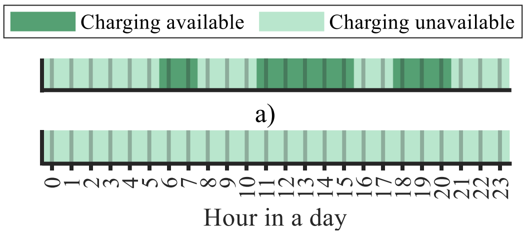

Fig. 6. Charging schedule of EV for scenario 2.

Figure 7 compares the consumer's electrical energy consumption with the EV charging station included in Scenario 2, in the case where the consumer does not have an installed PV system or a battery storage system.

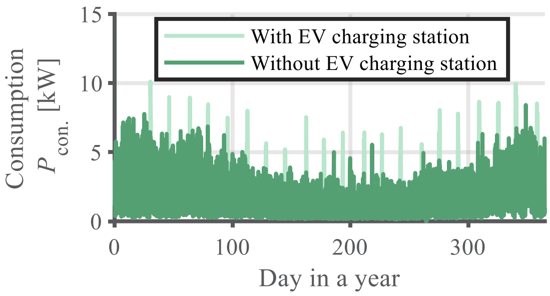

Fig. 7. Electrical energy consumption profile of a consumer with an integrated EV charging station under Scenario 2, without a PV and battery storage system.

Figure 7 shows that the inclusion of the EV charging station increases annual electrical energy consumption from 12.76 MWh to 13.60 MWh, corresponding to a 6,6% increase. Consequently, both the average and the maximum power demand increase. The average power rises from 1,457 kW to 1,552 kW (a 6.5% increase), while the maximum power demand increases from 8,42 kW to 10,12 kW (a 20.2% increase). Figure 8 presents the electrical energy consumption of the consumer with the EV charging station included under Scenario 3, assuming the consumer is equipped with a PV system and a battery storage system. Figure 8 shows the power flow to and from the consumer's grid connection under Scenario 2 with the EV charging station, where the consumer uses a PV system and a battery storage system. Figure 8a shows the power exchanged with the grid, while Figures 8b and 8c depict the battery SOC and the battery power, respectively.

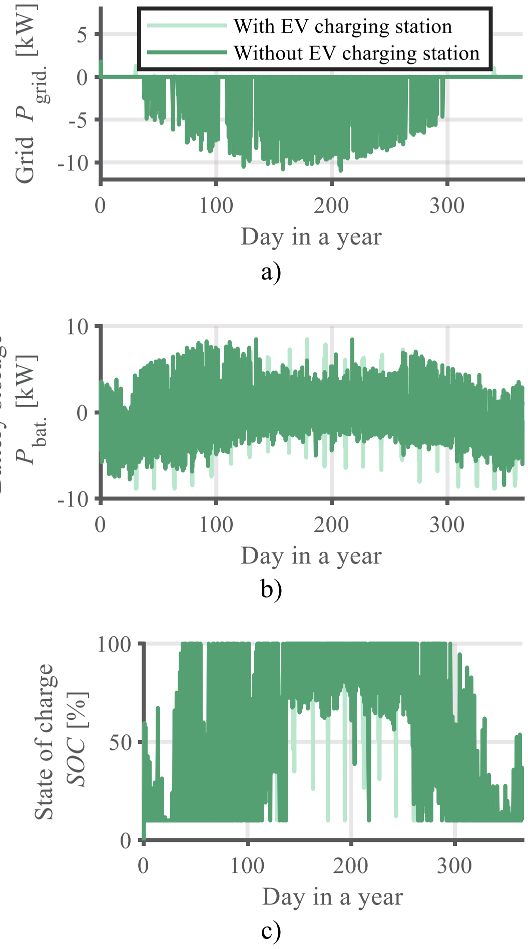

Fig. 8. Power flow profiles between the grid and the battery storage system, and the battery SOC for a consumer with an integrated EV charging station under Scenario 2.

As shown in Figure 8a, electrical energy was imported from the grid only twice, when the battery storage system was unable to supply sufficient energy. In this case, the total electrical energy imported from the grid amounted to only 1,62 kWh over the entire year. With such a charging strategy, the battery storage system is almost always able to provide enough electrical energy to enable near self-sufficient operation and practical independence from the grid. It can be observed that, even during the summer months, the battery SOC rarely drops below 50% of its nominal capacity, except for a few recurring EV charging periods. The operation of the battery storage system remains largely unchanged, as the EV is predominantly charged during daytime hours, allowing direct use of electrical energy generated by the PV system. Since sufficient time is available for charging, the EV charging station operates at a reduced power level of 4 kW, which is significantly more favorable for grid power demand than higher-power charging.

4. Economic analysis

A. Scenario 1

Based on electrical energy consumption, applicable tariff components, and the values of the agreed billing capacities, Figure 9 presents the structure of the electrical energy price for the consumer with the EV charging station included, without a PV system and a battery storage system, under Scenario 1.

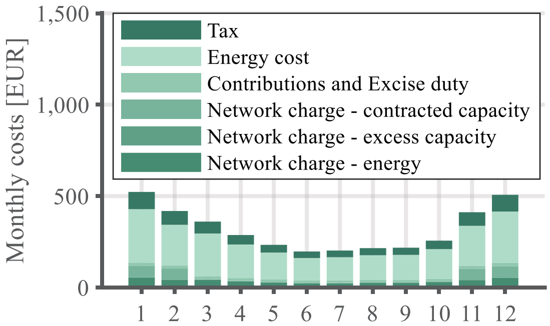

Fig. 9. Electrical energy price structure for a consumer with an integrated EV charging station under Scenario 1, without a PV and battery storage (adjusted contracted power levels consider the EV charging station).

As shown in Figure 9, the electrical energy costs for the consumer with an EV charging station included, without a PV system and a battery storage system, amount to 3,833 EUR when considering the currently applicable tariff components and the adjusted agreed billing capacities. For Scenario 1, the electrical energy costs for the consumer equipped with a PV system, a battery storage system, and an EV charging station were calculated under the credit-based scheme, as shown in Figure 10.

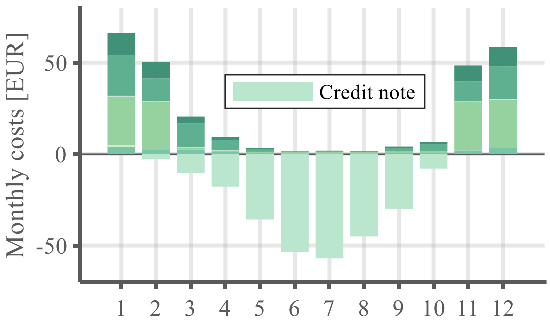

Fig. 10. Electrical energy price structure for a consumer with a PV and battery storage system, and an EV charging station under the credit-based scheme under Scenario 1.

Figure 10 shows that, under the credit-based scheme, the annual electrical energy costs for the consumer equipped with a PV system, a battery storage system, and an EV charging station in Scenario 1 amount to 273 EUR. Revenues from the sale of surplus electrical energy total 260 EUR, resulting in a net annual electrical energy cost of 13 EUR for the consumer under Scenario 1 within the credit-based scheme. Based on the investment costs of the PV and battery storage systems, the payback period for Scenario 1 under the credit support scheme was calculated to be approximately 6 years, as shown in Figure 11.

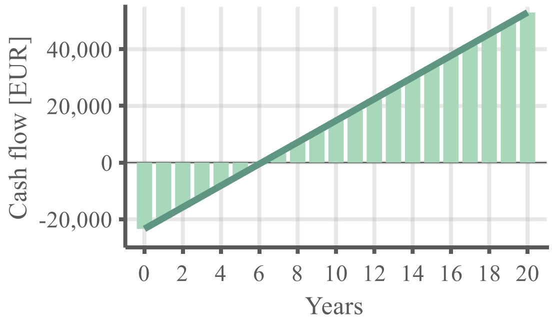

Fig. 11. Investment payback period for PV and battery storage unit system with support scheme credit note under Scenario 1.

B. *Scenario 2*

Based on electrical energy consumption, applicable tariff components, and the values of the agreed billing capacities, Figure 12 presents the structure of the electrical energy price for the consumer with the EV charging station included, without a PV system and a battery storage system, under Scenario 2.

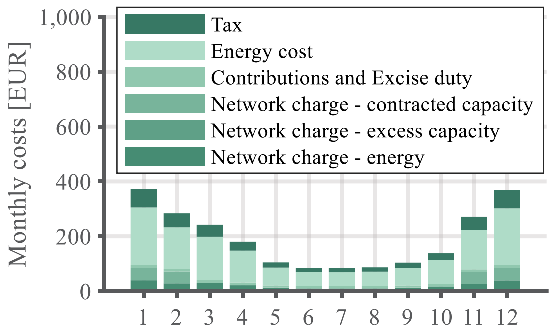

Fig. 12. Electrical energy price structure for a consumer with an integrated EV charging station under Scenario 2, without a PV and battery storage system (adjusted contracted power levels consider the EV charging station).

As shown in Figure 12, the electrical energy costs for the consumer with an EV charging station included, without a PV system and a battery storage system, amount to 2.321 EUR when considering the currently applicable tariff components and the adjusted agreed billing capacities. In addition, for Scenario 2, the electrical energy costs for the consumer equipped with a PV system, a battery storage system, and an EV charging station were also calculated under the credit-based scheme, as shown in Figure 13.

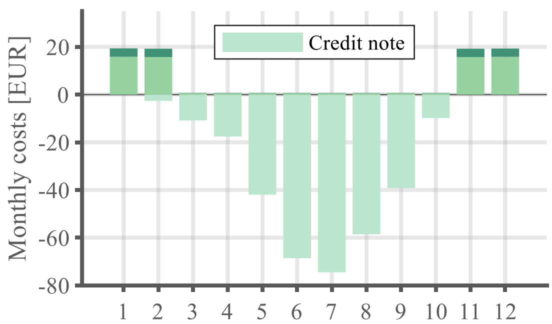

Fig. 13. Electrical energy price structure for a consumer with a PV system, battery storage system, and an EV charging station under the credit note scheme under Scenario 2.

Figure 13 shows that, under the credit-based scheme, the annual electrical energy costs for the consumer equipped with a PV system, a battery storage system, and an EV charging station in Scenario 2 amount to 82 EUR. Revenues from the sale of surplus electrical energy total 324 EUR, resulting in a positive annual balance of 240 EUR for the consumer under Scenario 2 within the credit-based scheme. In addition, the payback period of the investment in the PV system and the battery storage system was also calculated for Scenario 2, amounting to approximately ten years when the credit-based scheme is applied. The payback period for Scenario 2 is shown in Figure 14.

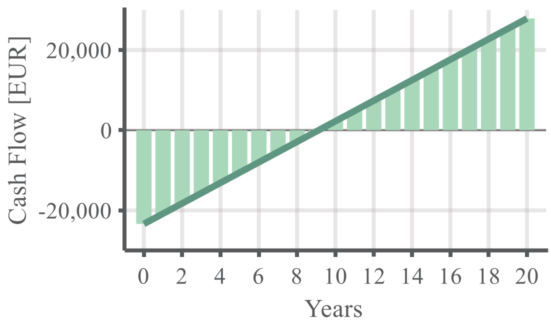

Fig. 14: Investment payback period for PV and battery storage system with support scheme credit note under Scenario 2.

5. Conclusion

This paper explores the economic viability of residential PV and battery storage systems under different EV charging scenarios within the current Slovenian electrical energy billing framework. Using 15-minute household consumption data, the study highlights the strong influence of EV driving intensity and charging behavior on electrical energy consumption, grid interaction, and investment payback periods. The results show that high-mileage EV use substantially increases electrical energy demand and peak power, but when combined with PV and battery storage systems and a credit-based support scheme, near self-sufficiency can be achieved. In this case, the investment payback period is reduced to approximately six years. Conversely, in the low-mileage scenario, daytime charging aligned with PV system electricity production enables very high self-consumption and minimal grid imports, but lower overall electrical energy savings result in a longer payback period of around 10 years. Overall, the analysis confirms that the economic performance of PV and battery storage systems strongly depends on EV usage patterns, charging strategies, and tariff structures. Coordinated EV charging and appropriately sized PV and battery systems are essential for maximizing both economic benefits and grid independence under the existing Slovenian electricity pricing scheme. Future research could therefore focus on evaluating different storage sizing strategies, or changes in EV usage patterns may affect both investment performance and grid interaction in residential prosumer systems. Moreover, future analyses could incorporate subsidy schemes for PV and battery storage system investments. However, such incentives were not included in this study due to their frequent temporal changes and variability, which would reduce the comparability and general validity of the presented results.

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